### Bakeoven Solar Project – DPO Public Hearing Comments

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<td>Fiona</td>
<td>Noonan</td>
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Hi Sarah –

Please find attached the applicant’s written comments and proposed revisions to the DPO, including a comment letter, Attachment 1 (DPO redline), Attachment 2 (figure), and Attachment 3 (supplemental tech memo from Tetra Tech on decommissioning). We are bringing hard copies for ODOE staff and the hearings officer. See you tonight. Thanks, Elaine
February 25, 2019

VIA EMAIL AND HAND DELIVERY

Sarah Esterson
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301

Re: Applicant Comments on Draft Proposed Order for Bakeoven Solar

Dear Sarah:

This letter provides comments by Bakeoven Solar, LLC (“Applicant”) on the Draft Proposed Order on Application for Site Certificate for the Bakeoven Solar Facility, dated January 17, 2020 (“DPO”). Applicant supports the Oregon Department of Energy (“ODOE”) findings that Applicant can safely and responsibly construct and operate the Bakeoven Solar Project (“Facility”). Applicant provides the following comments and revisions to the DPO for the reasons outlined below. A redline copy of the DPO is attached to this letter and provides Applicant’s requested language changes (Attachment 1).

A. Specific Comments and Proposed Revisions

Construction Start Date and Recommended General Standard Condition 1

The construction commencement date should be within five years after the date of Council action, instead of three years. This change is consistent with the information provided under Certificate Expiration (OAR-345-027-0013).

Revegetation Success Criteria and Recommended General Standard Condition 6

For Recommended General Standard Condition 6, Applicant interprets the statement “the certificate holder shall restore vegetation to the extent practicable and shall landscape all areas disturbed by construction” as applying to temporary work areas outside of the solar array fenced areas, which is consistent with statements from the Application for Site Certificate1. Revegetation within the fenced

1 Exhibit B, Section 3.6 Temporary Staging Area, “Temporary staging areas outside the fence will be reclaimed by removing the gravel surface, regrading to match adjacent contours, and reseeding. Staging areas within the fence line will be considered permanent impacts, and reclaimed at the Applicant’s discretion.” Exhibit P, Attachment P-3 Revegetation Plan, “This Revegetation Plan (Plan) describes methods, success criteria, and monitoring and reporting requirements for the restoration and revegetation of areas temporarily disturbed during the construction of the Bakeoven Solar Project (Facility). This Plan does not include areas occupied by permanent Facility components (i.e., the “footprint,” including the fenced solar arrays). The objective of revegetation is to restore temporarily disturbed areas to pre-disturbance conditions.”
areas will be at the discretion of Applicant, consistent with the NPDES 1200-C soil stabilization requirements, and intended for safe operation of the Facility. The DPO concluded that soil erosion will be minimized by the revegetation obligation of Recommended General Standard Condition 6, but Applicant maintains that soil stabilization will be achieved by measures outlined in the project’s NPDES 1200-C rather than Recommended General Standard Condition 6.

Evidence of Organizational Experience and Recommended Organization Expertise Condition 1

Applicant request that Recommended Organizational Expertise Condition 1 be removed because the Energy Facility Siting Council (“EFSC”) has previously issued site certificates to subsidiaries of Avangrid Renewables without this condition (i.e., Montague Wind Power Facility, Klondike III Wind Project, Leaning Juniper II Wind Project.) Applicant’s ability to operate the Facility will be documented annually in its annual report and through on-going compliance efforts as required by the site certificate. A change in corporate structure of Applicant’s parent company is not a good indicator of site certificate compliance or the experience needed to operate the Facility.

Clarification of Stream Setback and Recommended Land Use Condition 1

Applicants seek to clarify a discrepancy in the number of unnamed ephemeral or intermittent streams within the micrositing corridor presented in Exhibit K (Land Use) and the applicability of the 25-foot setback as described in WCLUDO 3.216(A)(2)(a)(3). Exhibit K reported 13 ephemeral and intermittent streams with the micrositing corridor but this was inconsistent with the number of streams report in Exhibit J (Wetlands). As described in Exhibit J, there are 14 ephemeral or intermittent streams within the project boundary, and of those streams, 11 streams are within the micrositing corridor (Table 1). To clarify what streams will receive a 25-foot setback, the Applicant requests that Recommended Land Use Condition 1 be revised to specific the correct number of streams, which is 10 plus Salt Creek.

For reference, Figure 1 depicts the affected streams (Attachment 2).

Wildlife Monitoring Plan Limitations and Recommended Fish and Wildlife Condition 9

Applicant requests that Recommended Fish and Wildlife Habitat Condition 9 be revised to limit post construction facility monitoring to the first phase of the Facility, and not “any phase of the facility.” This change is consistent with the Wildlife Monitoring Plan (WMP), which states, “the goals of this WMP are as follows: ...to determine the estimated bird fatality rates at Phase 1 of the Facility during the first year of operation.” WCLUDO Chapter 19 states, “as appropriate, the permit holder agrees to implement monitoring and mitigation actions that Wasco County determines appropriate after consultation with the Oregon Department of Fish and Wildlife, or other jurisdictional wildlife or natural resource agency.”

Bird fatalities are rare at solar facilities and it appropriate to use the results from the first phase to inform later phase. Oregon Department of Fish and Wildlife (“ODFW”) has reviewed the scope of the WMP (i.e., first phase, first year) and provide the following comment in a letter on the Application for Site Certificate (ASC), “ODFW appreciates the applicant’s willingness to conduct post-construction monitoring to better the local understanding of potential impacts from solar development on local bird and bat species.” Therefore, Applicant believes there is sufficient evidence to modify Recommended Fish and Wildlife Habitat Condition 9 to specify that post construction fatality monitoring is limited to Phase 1 of the Facility.
Noxious Weed Control Plan and Recommended Fish and Wildlife Habitat Condition 2

The Noxious Weed Control Plan included with the ASC is intended to comply with OAR 660-033-0130(38) and “not result in the unabeted introduction or spread of noxious weeds and other undesirable weed species.” Applicant plans to control noxious weeds in a manner to prevent the introduction or spread of noxious but recognizes complete removal of noxious weeds is difficult despite best efforts. Applicant defines success of the weed control as implementation of the Noxious Weed Control Plan.

Habitat Mitigation Plan and Recommended Fish and Wildlife Habitat Condition 3

As described in the Habitat Mitigation Plan (“HMP”), Applicant has proposed a mitigation option using a third-party mitigation provider to achieve greater conservation benefit than a traditional applicant-developed mitigation site. This option (“option 2”) defines a payment to a third-party land trust that includes land purchase, habitat enhancement, monitoring, and a contingency amount to ensure that habitat enhancements are successful. In addition, Applicant has proposed an option for a traditional applicant-developed mitigation site (“option 3”). Applicant will continue to work with ODOE and ODFW on finalizing the HMP prior to construction. Given the ongoing coordination with ODOE and ODFW, Applicant proposes a revision to Recommended Fish and Wildlife Condition 3 to delete the prescriptive language regarding the implementation of option 2 and 3. The specificity of this language raises the possibility of triggering a site certificate amendment depending on the ultimate resolution of the final HMP language. Further, Applicant maintains that any agreement finalized under option 2 is adequate to address the risk associated with the option 2 mitigation pathway. Applicant has partnered with two land trust recommended by ODFW (Western Rivers Conservancy and Deschutes Land Trust) with experience in habitat conservation in Oregon. The past success of these land trust is sufficient evidence to ensure compliance with EFSC’s Fish and Wildlife Standard.

Land Use Findings and Recommended Land Use Condition 9

Table 1 of the DPO provides the applicable approval criteria recommended by the Wasco County Special Advisory Group (“SAG”) and addressed by Applicant in Exhibit K. Applicant proposes refined findings to clarify that EFSC will be making affirmative land use findings for the Facility’s conditional use permit and site plan approval under the applicable approval criteria in the WCLUDO and Applicant will pursue the conditional use permit and site plan approval from the County pursuant to ORS 469.401(3). Applicant will pursue other County non-discretionary and ministerial permits in ordinary course prior to construction, as set forth in Exhibit E. Relatedly, Applicant proposes minor revisions to Recommended Land Use Condition 9 to incorporate the same into the condition language. Applicant recommends addressing the Goal 3 exception under Recommended Land Use Condition 11 given that ODOE is not treating the Goal 3 exception as a permit or approval under ORS 469.401(3).

Land Use Findings and Recommended Land Use Condition 11

Applicant proposes revised findings to address the Facility’s ability to obtain a Goal 3 exception and the process by which the County will implement the EFSC final order and site certificate. Applicant’s suggestions include more specific findings surrounding the application of the EFSC goal exception test and the non-applicability of the ORS 197 goal exception process, including the implementing regulations, whether during EFSC’s review or the County’s implementation of the findings pursuant to ORS 469.504(7).
B. Decommissioning

Applicant requests reconsideration of ODOE’s findings on decommissioning financial assurances because the DPO fails to consider fully Applicant’s proposal presented in the ASC and subsequent submittals. Applicant’s retirement plan and financial assurances presented in Exhibit W of the ASC reflect the economic realities of renewable energy projects and experiences in other jurisdictions, while still providing assurances that Applicant will decommission the Facility at the end of its useful life.

Applicant is proposing the following as an alternate decommissioning strategy, based on the reasons and justifications provided below:

- Calculate the estimated decommissioning and site restoration costs for the Facility;
- At the start of construction, post the full amount of the financial assurance;
- At COD (or in service date), reduce the posted financial assurance to $1;
- At year 20, or earlier if the Facility Power Purchase Agreement (“PAA”) is terminated early, post the full financial assurance minus scrap value for the life of the Facility; and
- Enter into a security interest agreement with EFSC and ODOE prior to construction granting EFSC/ODOE a priority security interest in the scrap value to ensure “first in line” prior ahead of other creditor.

The DPO describes the Applicant’s proposal as placing “extra risk upon the Department, the Council, and the State, with unclear value in return to the Department, Council, and State for accepting that risk,” but this conclusion disregards Applicant’s proposed safeguards. It also dismisses a significant policy factor that EFSC’s practice of requiring posting of financial assurance at the start of construction for newly built renewable energy projects has the effect of raising the cost of renewable energy production and consequently, increasing the prices of renewable energy for consumers. The cost of the financial assurance is built into the PPA and thereby raises the costs of the PPA, which in turn is passed along to the customer. Applicant argues that this is bad policy and warrants reconsideration.

Compared to other jurisdictions, EFSC’s practice of requiring full decommissioning at the start of construction without regards for scrap value for every year of operation results in some of the highest decommission financial assurance amounts, and the most expensive to carry, across the nation. For example, Table 1 lists financial assurances held by Avangrid Renewables through its project subsidiaries, with EFSC’s topping the table.
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Note: Dark green = Oregon EFSC project; Light Green = Oregon County CUP; Yellow = Solar

Table 1 indicates that other jurisdictions have taken an alternate approach to decommissioning and have adjusted decommissioning bonding requirements after recognizing one or more of the following factors: risk of project abandonment is low in the early years of operations, recognized scrap value, accepted alternate formulas for estimated decommissioning costs.

**Delivering Full Posting of the Decommissioning Security to Year 20 is Low Risk**

ODOE and its consultant, Golder, argue that delaying the full posting of the decommissioning security to Year 20 is too high risk. There is considerable evidence in the record to demonstrate otherwise and Applicant argues that ODOE’s findings are not based on substantial evidence. ODOE’s findings also fail to account for today’s market conditions, market demands, and contracting requirements.

Applicant provided the following information to support a conclusion that the risk of project abandonment during the PPA term for the first 20 years of operation is low and acceptable.

- **Solar panel manufactures guarantee energy production for 25+ years.** Warranties provided by solar panel manufactures demonstrate that the useful life of a solar project exceeds 25 years, and there is no reason to abandon facilities early in project life. EFSC may consider this useful life of solar projects as supportive of Applicant’s proposal to delay fully funding the decommissioning security until later in project life, at Year 20.

- **The PPA significantly reduce the likelihood of project abandonment.** A PPA is the legally binding agreement between an energy generation facility and an offtaker entity (offtaker). An offtaker can be a local, regional, or out-of-state electrical utility (e.g., North Wasco PUD, PacifiCorp, Avista) or a commercial end-user (e.g., data centers, industrial facilities). Whether the offtaker is a utility or a commercial end-user, both conduct due diligence before entering into the PPA to ensure reliable power. Such due diligence can include third-party evaluation of the energy resource, ability to deliver energy through the grid to its point of use, ability for the project to secure permits, the ability for the project to obtain financing, and the credit worthiness of the company building the energy generation facility. See OAR 860-089-0010 for example. The PPA defines the amount of energy the offtaker will purchase (total megawatt
hours per year), the duration of the contract (15+ years), the purchase price ($/MWhr), and any ancillary services (firming and shaping of renewable resources). The PPA provides the owner of the energy generating facility with certainty that if the project is build and operated consistent with the PPA, there will be a guaranteed revenue stream for the duration of the PPA. Because of this guaranteed rate of return, the risk of the project owner defaulting during the PPA term is low. The offtaker also has considerable interest in the project’s success over the PPA term, as they are using the renewable energy to serve their retail customers. Therefore, EFSC may consider projects with contracted PPA as unlikely to be abandoned, thereby reducing the risk associated with delayed posting of the decommissioning security to an acceptable level of risk during the PPA period.

- The PPA protects against abandonment due to technology changes. Renewable technology may improve over time, but the PPA obligates the offtaker to buy renewable energy from the project for the duration of the PPA term. Therefore, there is no risk that change in technology would undermine the value of the project during the PPA term.

- The PPA already requires development and operational security during the contract term. In most cases, a PPA requires the project developer/owner to post securities (e.g., letter of credit) tied to the successful development and operation of the project. The development security allows the offtaker to recovery costs if the project is not built or delayed. The operation security allows the offtaker to purchase energy elsewhere if the project fails to deliver energy as outlined in the PPA. The operational security is intended to be punitive and the security amount can exceed the total PPA value. This incentivizes the project owner to operate the project for the duration of the PPA period. EFSC may recognized that the decommissioning security provisions of the site certificate are not the only backstop preventing project abandonment. Again, this is another mechanism of the PPA that ensures that the risk associated with a delayed posting of the decommission security is acceptable because there are existing protections against abandonment.

- Renewable energy projects are in high demand and unlikely to be abandonment. The reality is that the demand for renewable energy projects are in high demand and have a low rate of failure (e.g., Oregon’s RPS, or Washington’s Carbon Free legislation). Renewable energy projects are not exposed to fluctuations in fuel costs like natural gas projects, or regulatory uncertainty like hydro projects. Forecasts on future energy trends stress a reliance on renewable energy, especially if there a price placed on carbon emissions as proposed during the last (and current) legislation session.

- No EFSC project has been abandoned. By definition, EFSC reviews and approves the largest energy projects in Oregon. These projects require significant investment to construct and operate, and if a developer defaults on a project, another developer would look to acquire the project assets and bring the project online. Throughout the energy industry, there is more evidence that renewable projects being resold (e.g., the Sun Edison bankruptcy) than projects being abandoned and requiring decommissioning by the permitting authority. On this basis, applicant argues that the DPO’s position that any hypothetical risk of project abandonment is unacceptable does not correspond to the realities of the commercial renewable energy market.
• **Applicant’s parent company, Avangrid Renewables, has the financial backing and expertise to operate the facility for the full project life.** Avangrid Renewables has a strong credit score and is a publicly traded company, therefore Applicant’s parent company have responsibility to its shareholder to only enter into PPAs where it can be successful. Especially, given the substantial finance penalties that Avangrid Renewables would face for project failure. Avangrid Renewables also partners with banks for financing of project construction – and these banks perform their own independent due diligence to verify that the project can be successful before providing construction financing.

• **Public Utility v. Independent Power Producer = Same Risk.** ODOE is recommending an alternative decommissioning strategy for the Boardman to Hemingway Transmission Line Project, which involves delaying a full posting of the decommissioning security until Year 51 once the facility is in service. A public utility has the ability to get rate recovery, relying on its rate-based customers. Comparatively, an independent power producer, with a long-term PPA, has a guaranteed revenue rather than rate recovery. The difference is rate recovery can be for a longer period than the term of the PPA, however, rate recovery is a settled rate resolved at the public utility commission whereas the PPA terms are fixed once executed.

**Allowing Scrap Value Credit is Low Risk**

Applicant also request that EFSC provide consideration of scrape value in determining the decommissioning security amount for the following reasons.

• **Scrap value credit is an accepted policy in other states and relies on a defined market index.** The record includes evidence and technical analysis describing the use of scrape value credit by other jurisdictions as well as the use of a defined market index for updating scrap value. See the Tetra Tech memorandum included as Attachment 3 for additional discussion.

• **Accounting only for steel in the scrape value credit minimizes risk.** As explained in the Tetra Tech memorandum included as Attachment 3, only steel scrape was included in the scrap valuation, Tetra Tech did not assume an increased credit for nonferrous materials. This ensures that the estimated value is conservative.

• **EFSC/ODOE would have a security interest in the Facility scrape value.** Applicant proposes a condition of approval requiring Applicant to enter into a security agreement with EFSC and ODOE prior to construction to grant EFSC/ODOE an enforceable security interest in the Facility scrape value, granting EFSC/ODOE a “first in line” right if it ever had to draw upon the scrap to decommission the facility. This mechanism ensures that EFSC, ODOE, the State, and its citizens are protected.

• **Wasco County allows for the consideration of scrape value credit.** WCLUDO 19.030(C)(19) specifically states that energy facilities can consider “the cost estimate and financial assurance may take into account salvage value associated with the project.” Applicant encourages that EFSC look to the applicable substantive approval criteria from the WCLUDO to support findings that consideration of scrape value credit. Other jurisdictions across the state also support the use scrap value credit when calculating decommissioning security.
Not only the WCLUDO allow for the consideration of scrape value credit, Wasco County has approved the use of scrap value credit for reducing decommissioning security totals for two renewable energy projects. EFSC should consider past approvals by Wasco County as evidence that an alternative decommissioning method is reasonable and locally acceptable. Wasco County Planning Commission approved the Imperial Wind Project’s (also by Avangrid Renewables) and the Wasco Solar Farm’s (by NuSun Energy) consideration of scrap value, allowing up to 50 percent of scrape value towards decommissioning.

**Substantial Evidence in the Record Refutes the Golder Memo Findings and Conclusions**

Applicant provides the following rebuttal to DPO’s reliance on the Golder memo, which appears to form the basis that ODOE relied when making findings to reject Applicant’s alternative decommissioning method. In addition, Applicant points ODOE back to the record for evidence upon which it can rely to make alternative findings supporting Applicant’s alternative decommissioning method. In short, the Golder’s memo is conclusory, does not consider all the evidence Applicant provided into the record, does not comprehensively analyze the proposed reasoning and findings in Exhibit W, and does not analyze risk. Applicant argues that ODOE should not rely on the Golder memo to support its findings, as it arguably does not amount to substantial evidence.

- **The Golder memo does not assess risk.** The DPO relies on the Golder memos to conclude that there be “significant risk” in accepting Applicant’s proposal; however, an assessment of risk was specifically excluded from Golder’s memo, which says “estimating the chance event probabilities is outside the scope of this technical memorandum.” Therefore, the DPO should not rely on the Golder memo for conclusions on likelihood of project abandonment.

- **The Golder memo had a predetermined outcome and should be disregard.** The DPO states that the scope of Golder’s review was to “review case history and context supporting ODOE’s policy of not allowing scrap value to be applied to decommissioning bond amounts” (emphasis added). This clearly shows that the intent of Golder’s review was to simply reinforce ODOE’s position rather than fairly consider Applicant’s proposal.

- **The Golder memo does not fully evaluate Applicant’s proposal.** The Golder memo does not consider Applicant’s proposal to grant EFSC and ODOE a security interest in scrape value using a security interest agreement (e.g., UCC filing), or Applicant’s willingness to reassess scrap value annually to account for price fluctuations. Nor did Golder consider that Applicant has only applied a minor portion of scrape value towards its decommissioning estimate. The Golder memo relies on out-of-industry examples (e.g., landfills, mines) to conclude that scrap estimates for renewable projects are unreliable. This is not a fair comparison, as Avangrid Renewables has direct experience with multiple jurisdictions accepting scrape value at more than a dozen of its operation facilities. Applicant’s consultant, Tetra Tech, also confirms that it has prepared decommissioning estimates for renewable projects in ten states, and all have accepted scrap value. Golder’s experts do not appear to have direct experience with assessing scrap value or preparing decommission estimates for renewable projects, and Golder fail to mention obvious examples of jurisdictions accepting scrap value towards decommissioning of renewable projects, such as the BLM. The BLM as authorized more than 6,000 MW of solar projects on federal land.

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and has a decommissioning policy that allows for consideration of scrap value. Golder’s oversights and lack of understanding of the renewables industry undermine its conclusions, and should not be used to dismiss Applicant’s proposal.

**Administrative Costs are Overestimated and Inflated**

The cost of managing the decommissioning process would typically fall on the certificate holder and their contractor. The cost estimate prepared for the Facility includes a 5 percent “home office & project management” line item and a 13 percent “contractor overhead and fee” line item for this purpose. Combined costs of approximately 18 percent for these two line items are typical, and include contractor and owner oversight, as well as management activities such as obtaining necessary environmental, transport, and disposal permits; hiring and management of project-specific staff; subcontractor procurement; financial management; and tracking of permit compliance. In the event of a certificate holder default, this cost will be assumed by a replacement contractor selected to perform decommissioning, and this cost is included in the decommissioning estimate. It will not fall on ODOE to perform this level of management and oversight.

In recent years, ODOE has adopted the practice of applying a separate, additional line item to cover their own potential costs should the certificate holder be unable to manage and direct the decommissioning process. This line has been set at an additional 10 percent of the total cost estimate provided by the certificate holder. While it is reasonable to anticipate that ODOE would incur additional costs if they need to step in on behalf of the certificate holder to decommission a facility, 10 percent is excessive. When certificate holder decommissions a project, ODOE will incur costs for compliance oversight; this cost is included in the “administration and project management” line described above.

In the case where the certificate holder is unable to manage the decommissioning process, ODOE would incur additional costs for the following activities: legal processes related to certificate holder insolvency, costs associated with soliciting proposals and executing a contract, and oversight of contractor performance. Applicant estimates that these efforts would require an average of no more than two Full-Time Equivalent (FTE) employees over the duration of the decommissioning process, plus an estimated 6 months for preparation and close-out. In the case of the Facility, the decommissioning process is anticipated to last 10 months, so a reasonable cost for ODOE time would be based on two FTEs for 16 months. Conservatively estimating the full cost of one professional state FTE employee, on average, including overhead and benefits, is $200,000 per year, this amounts to $333,000. In comparison, a flat 10 percent added onto the Facility decommissioning cost estimate for this service would amount to over $2,000,000. Given the actual anticipated level of effort required, this latter amount is excessive and unnecessary. Applicant requests that ODOE reconsider its findings on this point.

**Mandatory Conditions do Not Preclude an Alternate Decommissioning Method**

The mandatory conditions of approval do not prohibit EFSC from adopting an alternate decommissioning method. ODOE has already addressed this legal issue in the Boardman to Hemingway Project, as outlined in the Draft Proposed Order, dated May 22, 2019 (“B2H DPO”) and proposed condition language to address the requirements of the mandatory conditions. Applicant encourages ODOE to look to the B2H DPO for drafting conditions for Bakeoven.
Considerations for EFSC’s Policy Discussion

If EFSC does not agree with the Applicant’s proposed alternate decommissioning method, as described in the above bullets, there are variations EFSC may consider when addressing the presented policy question. Other considerations could include different timing of required decommissioning, the percentage of scrap value considered, use of different scrap indices, or consideration of the useful life of the projects rather than PPA terms.

C. Project Phasing

Applicant wishes to reiterate its plans to build the Facility in a single build-out or in phases, depending on customer or market demands. Applicant proposes revised findings in Section III.C to address the anticipated phasing and the process for pursuing phasing. If needed, the Applicant will seek EFSC’s approval to “split” or partially transfer the site certificate for each phase of development under OAR 345-027-0400. Applicant proposes revised findings in the DPO to inform the public and reviewing agencies of the full build-out potential for the site boundary. Applicant’s current phasing plans are as follows:

Table 2

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As provided in the proposed revised findings, Applicant is not seeking EFSC approval for the phased development set forth in Table 2 but provides the proposed schedule to document that future transfer approvals may be needed to facilitate full Facility build-out.

D. Conclusion

Thank you for your consideration of Applicant’s comments and suggested revisions. Applicant appreciates ODOE’s review of the project and looks forward to working with ODOE on making this project successful.

Sincerely,

Matt Hutchinson

Enclosures

cc: Brian Walsh - Avangrid
    Carrie Konkol – Tetra Tech
    Elaine Albrich - DWT
Land Use Condition 1: Prior to construction of the facility or any phase of the facility, the certificate holder shall demonstrate to the Department and Wasco County through mapping or other engineering drawing that the final facility layout, or layout of any final phase of the facility, complies with the following county setback requirements:

a. 25-foot minimum setback distance from permanent foundations (posts if in concrete, substation, O&M building) to all waterbodies (seasonal or permanent) not identified on any federal, state or local inventory. Waterbodies not identified on a federal, state or local inventory within the micrositing corridor include a portion of Salt Creek (which flows through Dead Dog Canyon) and 10 unnamed ephemeral or intermittent streams.
This technical memorandum provides a discussion in response to the review of Exhibit W of the Bakeoven Solar Project’s (the Facility) Application for Site Certificate performed by Golder, submitted November 5, 2019 to the Oregon Department of Energy (ODOE) (Golder 2019). This technical memorandum focuses on Section 1 of Golder’s review, regarding scrap value of facility components, and provides a subsection by subsection commentary regarding Tetra Tech’s professional opinion to Golder’s review.

Section 1.1 – A Summary of the Councils Current Policy Regarding Scrap Value

ODOE appears to be basing its current policy based on this statement from the Stateline Wind Project Final Order on Amendment #4, as quoted by Golder (2019:2):

> The Department concluded that there was a significant risk that third party creditors or other parties could assert a claim against the scrap or salvage value that might result in that value being unavailable to the State to offset site restoration costs.

As such, the current ODOE policy is based on the concerns Council members had in 2006: that the availability of scrap value offset was at risk due to third party claims, and that the actual value was not in question. It is our opinion that measures can be taken to mitigate this risk while still allowing a valuable commodity to be used to offset a portion of the overall decommissioning cost. Measures

could include a perfected security interest in Facility components, or liens on Facility real estate. ODOE’s cost to implement mitigation measures could be recovered in the ODOE management fee already included in the decommissioning estimate.

Section 1.2 – Fluctuation in Scrap Value

Golder’s review of historical scrap value focused on short-term trends. Tetra Tech understands that to accurately develop a trend that represents the 30-plus year life span of a renewable energy project, the long-term trend is a more appropriate method. As published by SteelBenchmarker (Attachment A), the long-term trend represents a substantial increase in value: from a January 2002 value of $70 a ton, to the January 2020 value of $261 per ton. At the time of Golder’s review, they noted a September 2019 value of $206 per ton (Golder 2019:3). This demonstrates that short-term fluctuations are not accurate in predicting long term trends, as the price is currently $261. Long-term trends clearly show a steady increase in scrap value, and with increasing demand and tightening environmental regulations, Tetra Tech assumes this trend will continue.

Section 1.3 – Practices or Policies Regarding Scrap Value in Other Jurisdictions

All of the examples that Golder cited in their review were unrelated to renewable energy projects (Golder 2019:3-4). For Golder’s review of California’s regulations, the focus was on solid and hazardous waste facilities. For Golder’s review of Alaska and British Columbia, the focus was on mine reclamation projects. For Golder’s review of Alberta, the focus was on waste, hazardous waste, and mine reclamation projects. In reviewing Washington State requirements, there is acknowledgement that scrap value is accepted for renewable energy facilities, but the law cited (denying scrap credit) was for a coal-fired power plant, not a renewable energy facility. We believe that not addressing the differences between renewable and non-renewable facilities indicates an inadequate review of the subject.

The statement in Golder’s summary is that none of the policies reviewed explicitly allowed the use of scrap value, and that some expressly disallowed it (Golder 2019:4). It is our opinion that where expressly disallowed, it is disallowed for facilities that present a great risk of substantial and long-term environmental damage, where future environmental remediation cost can be considerable. The proposed Facility does not have the potential to cause long-term environmental damage and will maintain a non-hazardous condition throughout its life cycle. Furthermore, the absence of a written policy expressly permitting the use of scrap value for renewable energy facilities is not evidence that scrap value credits are not accepted. As an example, the State of New York has published a Solar Guidebook (Attachment B) for decommissioning solar systems. Section 1, para 1.2, lists resale of components in decommissioning estimates. The State of New York does not have a published policy on scrap value, but as evidenced by their guidebook, they allow it. Tetra Tech has developed and updated decommissioning cost estimates in at least 10 states, and without
exception, all allow the use of scrap credit to offset decommissioning costs. These include California, Vermont, New York, South Dakota, Wyoming, Minnesota, Oklahoma, Colorado, Arizona and Virginia. In addition to these states, the Federal Bureau of Land Management, in their Solar Energy Program, Western Solar Plan (BLM 2017), specifically states they will consider salvage value of material when determining bond amount.

Section 1.4 – Recommendation

Tetra Tech does not agree with Golder’s recommendation to not accept scrap value. Golder recommends $100 per ton as a reasonable floor price, which they refer to as the value in November 2008, the beginning of the Great Recession (Golder 2019:4-5). The Great Recession began in December 2007 and ended June 2009. In December 2007, the value was $268 per ton. In June 2009, the value was $195 per ton, and recovered to pre-recession value soon after. Industry standard for demolition contractors is to sell when the market is favorable. During the short-term drops noted by Golder, contractors will typically stage or stockpile material to sell during periods of recovery, effectively treating this material considered more favorably than cash payment due to the possibility of a short term market driven windfall.

Final Observations

Tetra Tech understands ODOE’s reluctance to accept scrap and salvage value in renewable energy decommissioning estimates. It demonstrates a responsible and firm commitment to protect the citizens of Oregon from financial harm. We acknowledge that ODOE has likely been presented with decommissioning estimates that were overly simplistic and optimistic when it comes to the cost required to decommission a facility. Therefore, Tetra Tech takes a very conservative approach to decommissioning estimates, as described in Exhibit W of the Final Application for Site Certificate, and discussed further below.

Two terms that are often used interchangeably are "scrap value" and "salvage value." For calculating credits, Tetra Tech considers salvage value as the value received by selling a product in a secondary market as it was originally designed. We consider salvage a very risky assumption, as a market and future pricing for this material cannot be identified at the time a facility enters construction. Instead, Tetra Tech only assumes credit for scrap value, where the market is mature and established, and long-term trends can easily be determined.

We anticipate that a salvage market will develop in the future, but until that market can be identified and substantiated, we assume it does not currently exist. An example of a potential future salvage market would be the re-sale of solar modules. Tier 1 modules will retain 82–83 percent (Attachment C) of their initial generating capacity at the end of the project’s lifespan, so Tetra Tech

anticipates that at the time of decommissioning, a market will exist for the modules, which will result in additional value available to offset the decommissioning cost. To take the conservative approach a step further, Tetra Tech calculated all scrap as steel scrap, and we do not assume an increased credit for nonferrous metals.

When preparing the estimate for Exhibit W, all tasks and steps in the decommissioning work were clearly detailed and outlined, allowing a reviewer to easily follow the work from start to finish. Scrap value was listed separately by item, and the cost to prepare, load, and ship the scrap was captured separately. Our goal was to provide a clear and accurate estimate, leaving nothing to the reviewer’s interpretation.

While Golder bases their recommendation to not accept scrap value on ODOE’s objective to minimize risk to the State of Oregon (Golder 2019:4-5), Tetra Tech believes that this technical memorandum provides ample justification for the value we have assigned to scrap in the Facility’s decommissioning estimate in Exhibit W, and have provided numerous examples of jurisdictions where scrap value is accepted. Decommissioning a solar facility is a standard clean demolition project, and the sale of recyclable material is standard practice. It is our opinion that the appropriate place to address the risk associated with scrap value is through the Retirement and Financial Assurance Standard (Oregon Administrative Rules 345-022-0050), not by denying the credit for scrap value.
Attachment A –
SteelBenchmarker Scrap Price
SteelBenchmarker™ Scrap Price

USA, delivered to steel plant
(AMM scrap price data, Jan. 2002 - Jan. 2007; SteelBenchmarker data begins Feb. 2007)
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<td>9</td>
<td>3.6%</td>
<td>267</td>
<td>4</td>
<td>1.5%</td>
</tr>
<tr>
<td>20-Dec-19</td>
<td>247</td>
<td>18</td>
<td>7.9%</td>
<td>280</td>
<td>19</td>
<td>7.3%</td>
<td>286</td>
<td>19</td>
<td>7.1%</td>
</tr>
<tr>
<td>13-Jan-20</td>
<td>261</td>
<td>14</td>
<td>5.7%</td>
<td>297</td>
<td>17</td>
<td>6.1%</td>
<td>298</td>
<td>12</td>
<td>4.2%</td>
</tr>
</tbody>
</table>

Notes: ** Steel scrap delivered to steel plant
#1 heavy melting – demolition scrap that is at least ¼” thick. This grade does not include
the heavy “p & s” (plate and structural ) category that includes the very thick scrap items.
Shredded – largely old cars and some appliances – for all but the West Coast (CA, OR & WA).
#1 busheling – new sheet steel scrap.

Prices released on Wednesdays following the 2nd and 4th Mondays of the month at 9:00 AM to Price
Assessment Providers. If a price is not indicated, fewer than ten (10) price inputs were received at that time.
The first price release was for Feb. 12, 2007 for data go to steelbenchmark.com/files/history2.pdf.

For product specifications refer to last page, or go to steelbenchmark.com/specifications.
Attachment B – New York Solar Panel Decommissioning Guidebook
Decommissioning Solar Panel Systems

Information for local governments and landowners on the decommissioning of large-scale solar panel systems.
Section Contents

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   1.2 Estimated Cost of Decommissioning ......... 146

2. Ensuring Decommissioning ......................... 146
   2.1 Financial mechanisms ......................... 147
   2.2 Nonfinancial mechanisms ..................... 148
   2.3 Examples of abandonment and
       decommissioning provisions .................... 148
   2.4 Checklist for Decommissioning Plans ......... 148
Overview

We provide information for local governments and landowners on the decommissioning of large-scale solar panel systems through the topics of decommissioning plans and costs and financial and non-financial mechanisms in land-lease agreements.

As local governments develop solar regulations and landowners negotiate land leases, it is important to understand the options for decommissioning solar panel systems and restoring project sites to their original status.

From a land use perspective, solar panel systems are generally considered large-scale when they constitute the primary use of the land and can range from less than one acre in urban areas to 10 or more acres in rural areas. Depending on where they are sited, large-scale solar projects can have habitat, farmland, and aesthetic impacts. As a result, large-scale systems must often adhere to specific development standards.

1. Abandonment and Decommissioning

Abandonment occurs when a solar array is inactive for a certain period of time.

- Abandonment requires that solar panel systems be removed after a specified period of time if they are no longer in use. Local governments establish timeframes for the removal of abandoned systems based on aesthetics, system size and complexity, and location. For example, the Town of Geneva, NY, defines a solar panel system as abandoned if construction has not started within 18 months of site plan approval, or if the completed system has been nonoperational for more than one year.22

- Once a local government determines a solar panel system is abandoned and has provided thirty (30) days prior written notice to the owner it can take enforcement actions, including imposing civil penalties/fines, and removing the system and imposing a lien on the property to recover associated costs.

Decommissioning is the process for removing an abandoned solar panel system and remediating the land.

- When describing requirements for decommissioning sites, it is possible to specifically require the removal of infrastructure, disposal of any components, and the stabilization and re-vegetation of the site.

1.1 Decommissioning Plans

Local governments may require having a plan in place to remove solar panel systems at the end of their lifecycle, which is typically 20-40 years. A decommissioning plan outlines required steps to remove the system, dispose of or recycle its components, and restore the land to its original state. Plans may also include an estimated cost schedule and a form of decommissioning security (see Table 1).
1.2 Estimated Cost of Decommissioning

Given the potential costs of decommissioning and land reclamation, it is reasonable for landowners and local governments to proactively consider system removal guarantees. A licensed professional engineer, preferably with solar development experience, can estimate decommissioning costs, which vary across the United States. Decommissioning costs will vary depending upon project size, location, and complexity. Table 1 provides an estimate of potential decommissioning costs for a ground-mounted 2-MW solar panel system. Figures are based on estimates from the Massachusetts solar market. Decommissioning costs for a New York solar installation may differ. Some materials from solar installations may be recycled, reused, or even sold resulting in no costs or compensation. Consider allowing a periodic reevaluation of decommissioning costs during the project’s lifetime by a licensed professional engineer, as costs could decrease, and the required payment should be reduced accordingly.

Table 1: Sample list of decommissioning tasks and estimated costs

<table>
<thead>
<tr>
<th>Tasks</th>
<th>Estimated Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Remove Rack Wiring</td>
<td>$2,459</td>
</tr>
<tr>
<td>Remove Panels</td>
<td>$2,450</td>
</tr>
<tr>
<td>Dismantle Racks</td>
<td>$12,350</td>
</tr>
<tr>
<td>Remove Electrical Equipment</td>
<td>$1,850</td>
</tr>
<tr>
<td>Breakup and Remove Concrete Pads or Ballasts</td>
<td>$1,500</td>
</tr>
<tr>
<td>Remove Racks</td>
<td>$7,800</td>
</tr>
<tr>
<td>Remove Cable</td>
<td>$6,500</td>
</tr>
<tr>
<td>Remove Ground Screws and Power Poles</td>
<td>$13,850</td>
</tr>
<tr>
<td>Remove Fence</td>
<td>$4,950</td>
</tr>
<tr>
<td>Grading</td>
<td>$4,000</td>
</tr>
<tr>
<td>Seed Disturbed Areas</td>
<td>$250</td>
</tr>
<tr>
<td>Truck to Recycling Center</td>
<td>$2,250</td>
</tr>
<tr>
<td><strong>Current Total</strong></td>
<td><strong>$60,200</strong></td>
</tr>
<tr>
<td><strong>Total After 20 Years (2.5% inflation rate)</strong></td>
<td><strong>$98,900</strong></td>
</tr>
</tbody>
</table>

2. Ensuring Decommissioning

Landowners and local governments can ensure appropriate decommissioning and reclamation by using financial and regulatory mechanisms. However, these mechanisms come with tradeoffs. Including decommissioning costs in the upfront price of solar projects increases overall project costs, which could discourage solar development. As a result, solar developers are sometimes hesitant to provide or require financial surety for decommissioning costs.

It is also important to note that many local governments choose to require a financial mechanism for decommissioning. Although similar to telecommunications installations, there is no specific authority to do so as part of a land use approval for solar projects (see Table 2). Therefore, a local government should consult their municipal attorney when evaluating financial mechanisms.
The various financial and regulatory mechanisms to decommission projects are detailed below.

### Table 2: Relevant Provisions of General City, Town, and Village Laws Relating to Municipal Authority to Require Conditions, Waivers, and Financial Mechanisms

<table>
<thead>
<tr>
<th>Site Plan Review</th>
<th>General City Law</th>
<th>Town Law</th>
<th>Village Law</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conditions</td>
<td>27-a (4)</td>
<td>274-a (4)</td>
<td>7-725-a (4)</td>
</tr>
<tr>
<td>Waivers</td>
<td>27-a (5)</td>
<td>274-a (5)</td>
<td>7-725-a (5)</td>
</tr>
<tr>
<td>Performance bond or other security</td>
<td>27-a (7)</td>
<td>274-a (7)</td>
<td>7-725-a (7)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Subdivision</th>
<th>General City Law</th>
<th>Town Law</th>
<th>Village Law</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waivers</td>
<td>33 (7)</td>
<td>277 (7)</td>
<td>7-730 (7)</td>
</tr>
<tr>
<td>Performance bond or other security</td>
<td>33 (8)</td>
<td>277 (9)</td>
<td>7-730 (9)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Special</th>
<th>General City Law</th>
<th>Town Law</th>
<th>Village Law</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conditions</td>
<td>27-b (4)</td>
<td>274-b (4)</td>
<td>7-725-b (4)</td>
</tr>
<tr>
<td>Waivers</td>
<td>27-b (5)</td>
<td>274-b (5)</td>
<td>7-725-b (5)</td>
</tr>
</tbody>
</table>

Source: Referenced citations may be viewed using the NYS Laws of New York Online

Excerpts from these statutes are also contained within the "Guide to Planning and Zoning Laws of New York State," New York State Division of Local Governments Services, June 2011: [https://www.dos.ny.gov/lg/publications/Guide_to_planning_and_zoning_laws.pdf](https://www.dos.ny.gov/lg/publications/Guide_to_planning_and_zoning_laws.pdf)

### 2.1 Financial mechanisms

**Decommissioning Provisions in Land-Lease Agreements.** If a decommission plan is required, public or private landowners should make sure a decommissioning clause is included in the land-lease agreement. This clause may depend on the decommissioning preferences of the landowner and the developer. The clause could require the solar project developer to remove all equipment and restore the land to its original condition after the end of the contract, or after generation drops below a certain level, or it could offer an option for the landowner to buy-out and continue to use the equipment to generate electricity. The decommissioning clause should also address abandonment and the possible failure of the developer to comply with the decommissioning plan. This clause could allow for the landowner to pay for removal of the system or pass the costs to the developer.

**Decommissioning Trusts or Escrow Accounts.** Solar developers can establish a cash account or trust fund for decommissioning purposes. The developer makes a series of payments during the project's lifecycle until the fund reaches the estimated cost of decommissioning. Landowners or third-party financial institutions can manage these accounts. Terms on individual payment amounts and frequency can be included in the land lease.

**Removal or Surety Bonds.** Solar developers can provide decommissioning security in the form of bonds to guarantee the availability of funds for system removal. The bond amount equals the decommissioning and reclamation costs for the entire system. The bond must remain valid until the decommissioning obligations have been met. Therefore, the bond must be renewed or replaced if necessary to account for any changes in the total decommissioning cost.

**Letters of credit.** A letter of credit is a document issued by a bank that assures landowners a payment up to a specified amount, given that certain conditions have been met. In the case that the project developer fails to remove the system, the landowner can claim the specified amount to cover decommissioning costs. A letter of credit should clearly state the conditions for payment, supporting documentation landowners must provide, and an expiration date. The document must be continuously renewed or replaced to remain effective until obligations under the decommissioning plan are met.
2.2 Nonfinancial mechanisms

Local governments can establish nonfinancial decommissioning requirements as part of the law. Provisions for decommissioning large-scale solar panel systems are similar to those regulating telecommunications installations, such as cellular towers and antennas. The following options may be used separately or together.

- **Abandonment and Removal Clause.** Local governments can include in their zoning code an abandonment and removal clause for solar panel systems. These cases effectively become zoning enforcement matters where project owners can be mandated to remove the equipment via the imposition of civil penalties and fines, and/or by imposing a lien on the property to recover the associated costs. To be most effective, these regulations should be very specific about the length of time that constitutes abandonment. Establishing a timeframe for the removal of a solar panel system can be based on system aesthetics, size, location, and complexity. Local governments should include a high degree of specificity when defining “removal” to avoid ambiguity and potential conflicts.

- **Special Permit Application.** A local government may also mandate through its zoning code that a decommissioning plan be submitted by the solar developer as part of a site plan or special permit application. Having such a plan in place allows the local government, in cases of noncompliance, to place a lien on the property to pay for the costs of removal and remediation.

- **Temporary Variance/Special Permit Process.** As an alternative to requiring a financial mechanism as part of a land use approval, local governments could employ a temporary variance/special permit process (effectively a re-licensing system). Under this system, the locality would issue a special permit or variance for the facility for a term of 20 or more years; once expired (and if not renewed), the site would no longer be in compliance with local zoning, and the locality could then use their regular zoning enforcement authority to require the removal of the facility.

2.3 Examples of abandonment and decommissioning provisions

The New York State Model Solar Energy Law provides model language for abandonment and decommissioning provisions in the Model Law section of this Guidebook.

The following provide further examples that are intended to be illustrative and do not confer an endorsement of content:

- **Town of Geneva, N.Y., § 130-4(D):** ecode360.com/28823382
- **Town of Olean, N.Y., § 10.25.5:** https://www.cityofOLEAN.org/council/minutes/ccmin2015-04-14.pdf

2.4 Checklist for Decommissioning Plans

The following items are often addressed in decommissioning plans requirements:

- Defined conditions upon which decommissioning will be initiated (i.e., end of land lease, no operation for 12 months, prior written notice to facility owner, etc.).
- Removal of all nonutility owned equipment, conduit, structures, fencing, roads, and foundations.
- Restoration of property to condition prior to solar development.
- The timeframe for completion of decommissioning activities.
- Description of any agreement (e.g., lease) with landowner regarding decommissioning.
- The party responsible for decommissioning.
- Plans for updating the decommissioning plan.
- Before final electrical inspection, provide evidence that the decommissioning plan was recorded with the Register of Deeds.

Questions?

If you have any questions regarding the decommissioning of solar panels, please email questions to cleanenergyhelp@nyserda.ny.gov or request free technical assistance at nyserda.ny.gov/SolarGuidebook. The NYSERDA team looks forward to partnering with communities across the state to help them meet their solar energy goals.
Attachment C – Example Product Data Sheets and Power Output Warranties
LR4-72HIBD
415~435M

High Efficiency
Low LID Bifacial PERC with
Half-cut Technology

10-year Warranty for Materials and Processing;
30-year Warranty for Extra Linear Power Output

-0.45%
30-year Power
Warranty Annual
Power Attenuation
-0.45%

84.95%

Complete System and Product Certifications
IEC 61215, IEC61730, UL1703
ISO 14001: 2004: ISO Environment Management System
TS62147: Guideline for module design qualification and type approval
OHAS 18001: 2007 Occupational Health and Safety

* Specifications subject to technical changes and tests, LONGi Solar reserves the right of interpretation.

Front side performance equivalent to conventional low LID mono PERC:
- High module conversion efficiency (up to 19.4%)
- Better energy yield with excellent low irradiance performance and temperature coefficient
- First year power degradation <2%

Bifacial technology enables additional energy harvesting from rear side (up to 25%)

Glass/glass lamination ensures 30 year product lifetime, with annual power degradation < 0.45%,
1500V compatible to reduce BOS cost

35mm frame design enables easy installation and robust mechanical strength

Solid PID resistance ensured by solar cell process optimization and careful module 90M selection

Reduced resistive loss with lower operating current

Higher energy yield with lower operating temperature

Reduced hot spot risk with optimized electrical design and lower operating current

Note: Due to continuous technical innovation, R&D and improvement, technical data above mentioned may be of modification accordingly. LONGi Solar have the sole right to make such modification at anytime without further notice; Demanding party shall request for the latest datasheet for such as contract need, and make it a consisting and binding part of lawful documentation duly signed by both parties.
LR4-72HIBD 415~435M

**Design (mm)**

- Cell Orientation: S44 (6x4)
- Junction Box: IP68, three diodes
- Output Cable: 4mm², 300mm in length, length can be customized
- Glass: Dual glass
- Frame: Anodized aluminum alloy frame
- Weight: 29.5kg
- Dimension: 2131×1052×35mm
- Packaging: 30pcs per pallet
  - 550pcs per 20GP
  - 600pcs per 40HC

**Mechanical Parameters**

- Operational Temperature: -40°C ~ +65°C
- Power Output Tolerance: ± 1.0%
- Voc and Isc Tolerance: ± 1.0%
- Maximum System Voltage: DC1500V (IEC/L)
- Maximum Series Fuse Rating: 20A
- Nominal Operating Cell Temperature: 25°C ± 2°C
- Safety Class: Class II
- Fire Rating: UL Type 6
- Bifacial: Glazing: 65±5%

**Operating Parameters**

**Electrical Characteristics**

<table>
<thead>
<tr>
<th>Model Number</th>
<th>LR4-72HIBD-415M</th>
<th>LR4-72HIBD-420M</th>
<th>LR4-72HIBD-425M</th>
<th>LR4-72HIBD-430M</th>
<th>LR4-72HIBD-435M</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Testing Condition</strong></td>
<td>STC</td>
<td>NOCT</td>
<td>STC</td>
<td>NOCT</td>
<td>STC</td>
</tr>
<tr>
<td><strong>Maximum Power (Pmax/W)</strong></td>
<td>415</td>
<td>308.6</td>
<td>420</td>
<td>312.3</td>
<td>425</td>
</tr>
<tr>
<td><strong>Open Circuit Voltage (Voc/V)</strong></td>
<td>49.0</td>
<td>45.6</td>
<td>49.2</td>
<td>45.8</td>
<td>49.4</td>
</tr>
<tr>
<td><strong>Short Circuit Current (Isc/A)</strong></td>
<td>10.73</td>
<td>8.69</td>
<td>10.80</td>
<td>8.74</td>
<td>10.86</td>
</tr>
<tr>
<td><strong>Voltage at Maximum Power (Vmp/V)</strong></td>
<td>40.6</td>
<td>37.7</td>
<td>40.8</td>
<td>37.9</td>
<td>41.0</td>
</tr>
<tr>
<td><strong>Current at Maximum Power (Imp/A)</strong></td>
<td>10.23</td>
<td>8.19</td>
<td>10.30</td>
<td>8.25</td>
<td>10.37</td>
</tr>
<tr>
<td><strong>Module Efficiency (%)</strong></td>
<td>18.5</td>
<td>18.7</td>
<td>19.0</td>
<td>19.2</td>
<td>19.4</td>
</tr>
</tbody>
</table>

STC (Standard Testing Conditions): Irradiance 1000W/m², Cell Temperature 25°C, Spectra AM1.5

NOCT (Nominal Operating Cell Temperature): irradiance 800W/m², Ambient Temperature 20°C, Spectra AM1.5, Wind at 1m/S

Electrical characteristics with different rear side power gain (reference to 425W front)

<table>
<thead>
<tr>
<th>Pmax /W</th>
<th>Voc/V</th>
<th>Isc/A</th>
<th>Vmp/V</th>
<th>Imp/A</th>
<th>Pmax gain</th>
</tr>
</thead>
<tbody>
<tr>
<td>446</td>
<td>49.4</td>
<td>11.41</td>
<td>41.0</td>
<td>10.88</td>
<td>5%</td>
</tr>
<tr>
<td>468</td>
<td>49.4</td>
<td>11.95</td>
<td>41.0</td>
<td>11.40</td>
<td>10%</td>
</tr>
<tr>
<td>489</td>
<td>49.5</td>
<td>12.49</td>
<td>41.1</td>
<td>11.92</td>
<td>15%</td>
</tr>
<tr>
<td>510</td>
<td>49.5</td>
<td>13.04</td>
<td>41.1</td>
<td>12.44</td>
<td>20%</td>
</tr>
<tr>
<td>531</td>
<td>49.5</td>
<td>13.58</td>
<td>41.1</td>
<td>12.96</td>
<td>25%</td>
</tr>
</tbody>
</table>

**Temperature Ratings (STC)**

- Temperature Coefficient of Isc: +0.06%/°C
- Temperature Coefficient of Voc: -0.30%/°C
- Temperature Coefficient of Pmax: -0.37%/°C

**Mechanical Loading**

- Front Side Maximum Static Loading: 5400Pa
- Rear Side Maximum Static Loading: 2400Pa
- Hailstone Test: 25mm Hailstone at the speed of 23m/s

**I-V Curve**

---

**Note:** Due to continuous technical innovation, R&D and improvement, technical data above mentioned may be of modification accordingly. LONGI Solar have the sole right to make such modification at anytime without further notice; Demanding party shall request for the latest datasheet for such as contract need, and make it a consisting and binding part of lawful documentation duly signed by both parties.
These double-glass modules assembled with bifacial PERCIUM cells have the capability of converting lights incident on their rear side into electricity on top of what is being generated by the front side, making them the best-performed and the most cost-effective modules in terms of solar energy generation as well as tolerance for harsh environment and extreme weather conditions.

**Superior Warranty**
- 12-year product warranty
- 30-year linear power output warranty

**0.5% Annual Degradation Over 30 years**

**Comprehensive Certificates**
- IEC 61215, IEC 61730
- ISO 9001: 2015 Quality management systems
- ISO 14001: 2015 Environmental management systems
- OHSAS 18001: 2007 Occupational health and safety management systems
- IEC TS 62941: 2016 Terrestrial photovoltaic (PV) modules – Guidelines for increased confidence in PV module design qualification and type approval

**Additional Value From 30-Year Warranty**

---

**390W Bifacial Mono PERC Double Glass Module**

JAM72D09 370-390/BP Series
**OPERATING CONDITIONS**

<table>
<thead>
<tr>
<th></th>
<th>JAM72D09 370-390/BP</th>
<th>JAM72D09 375-390/BP</th>
<th>JAM72D09 380-390/BP</th>
<th>JAM72D09 385-390/BP</th>
<th>JAM72D09 390-390/BP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum System Voltage</td>
<td>1500V DC (IEC)</td>
<td>1500V DC (IEC)</td>
<td>1500V DC (IEC)</td>
<td>1500V DC (IEC)</td>
<td>1500V DC (IEC)</td>
</tr>
<tr>
<td>Operating Temperature</td>
<td>-40°C to +85°C</td>
<td>-40°C to +85°C</td>
<td>-40°C to +85°C</td>
<td>-40°C to +85°C</td>
<td>-40°C to +85°C</td>
</tr>
<tr>
<td>Maximum Series Fuse</td>
<td>20A</td>
<td>20A</td>
<td>20A</td>
<td>20A</td>
<td>20A</td>
</tr>
<tr>
<td>Maximum Static Load,Front*</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
</tr>
<tr>
<td>Maximum Static Load,Back**</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
<td>6400Pa</td>
</tr>
<tr>
<td>NOCT</td>
<td>45±2°C</td>
<td>45±2°C</td>
<td>45±2°C</td>
<td>45±2°C</td>
<td>45±2°C</td>
</tr>
<tr>
<td>Bifaciality*</td>
<td>70±5%</td>
<td>70±5%</td>
<td>70±5%</td>
<td>70±5%</td>
<td>70±5%</td>
</tr>
</tbody>
</table>

*For NexTracker installations static loading performance: front load measure 2400Pa, while back load measures 2400Pa.

**ELECTRICAL CHARACTERISTICS WITH DIFFERENT REAR SIDE POWER GAIN (REFERENCE TO 385W FRONT)**

<table>
<thead>
<tr>
<th>Backside Power Gain</th>
<th>5%</th>
<th>10%</th>
<th>15%</th>
<th>20%</th>
<th>25%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated Max Power(Pmax) [W]</td>
<td>404</td>
<td>424</td>
<td>443</td>
<td>462</td>
<td>481</td>
</tr>
<tr>
<td>Open Circuit Voltage(Voc) [V]</td>
<td>49.11</td>
<td>49.11</td>
<td>49.11</td>
<td>49.21</td>
<td>49.21</td>
</tr>
<tr>
<td>Max Power Voltage(Vmp) [V]</td>
<td>40.33</td>
<td>40.33</td>
<td>40.33</td>
<td>40.43</td>
<td>40.43</td>
</tr>
<tr>
<td>Short Circuit Current(Isoc) [A]</td>
<td>10.59</td>
<td>11.10</td>
<td>11.60</td>
<td>12.11</td>
<td>12.61</td>
</tr>
<tr>
<td>Max Power Current(Imp) [A]</td>
<td>10.02</td>
<td>10.51</td>
<td>10.98</td>
<td>11.43</td>
<td>11.90</td>
</tr>
</tbody>
</table>

*For NexTracker installations static loading performance: front load measure 2400Pa, while back load measures 2400Pa.

**CHARACTERISTICS**

**Current-Voltage Curve**  JAM72D09-380/BP

**Power-Voltage Curve**  JAM72D09-380/BP

**Current-Voltage Curve**  JAM72D09-380/BP

**ELECTRICAL PARAMETERS AT STC**

<table>
<thead>
<tr>
<th>Type</th>
<th>JAM72D09-370/BP</th>
<th>JAM72D09-375/BP</th>
<th>JAM72D09-380/BP</th>
<th>JAM72D09-385/BP</th>
<th>JAM72D09-390/BP</th>
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<tr>
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<td>375</td>
<td>380</td>
<td>385</td>
<td>390</td>
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<tr>
<td>Open Circuit Voltage(Voc) [V]</td>
<td>48.20</td>
<td>48.51</td>
<td>48.81</td>
<td>49.11</td>
<td>49.42</td>
</tr>
<tr>
<td>Maximum Power Voltage(Vmp) [V]</td>
<td>39.41</td>
<td>39.73</td>
<td>40.02</td>
<td>40.33</td>
<td>40.63</td>
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<tr>
<td>Short Circuit Current(Isoc) [A]</td>
<td>9.91</td>
<td>9.97</td>
<td>10.03</td>
<td>10.09</td>
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<tr>
<td>Module Efficiency [%]</td>
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<td>19.0</td>
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<td>Power Tolerance</td>
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<td>Temperature Coefficient of Isc(α_Isc)</td>
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<tr>
<td>Temperature Coefficient of Voc(β_Voc)</td>
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<tr>
<td>Temperature Coefficient of Pmax(γ_Pmp)</td>
<td>-0.370%/°C</td>
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</table>

**STC Irradiance 1000W/m², cell temperature 25°C, AM1.5G**

Remark: Electrical data in this catalog do not refer to a single module and they are not part of the offer.They only serve for comparison among different module types.

The efficiency of the bifacial PERC glass-glass modules at 200W/m² to that at 1000W/m² is 98%.

*Bifaciality=Pmax,rear/Rated Pmax,front

**SPECIFICATIONS**

**MECHANICAL DIAGRAMS**

**Cell**

- Weight: 29.8kg±3%
- Dimensions: 2004±2mm×1000±2mm×30±1mm
- Cable Cross Section Size: 4mm²
- No. of cells: 72(6x12)
- Junction Box: IP68, 3 diodes
- Connector: QC 4.10-35
- Packaging Configuration: 34 Per Pallet

**Grounding holes**

- 6 places

**Mounting holes**

- 8 places

**Draining holes**

- 8 places

**Units: mm**

<table>
<thead>
<tr>
<th>Monting Holes</th>
<th>JAM72D09-370/BP</th>
<th>JAM72D09-375/BP</th>
<th>JAM72D09-380/BP</th>
<th>JAM72D09-385/BP</th>
<th>JAM72D09-390/BP</th>
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<tr>
<td>4 Places for NexTracker</td>
<td>380</td>
<td>48.81</td>
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<td>49.42</td>
<td>40.63</td>
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<td>9.60</td>
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**CHARACTERISTICS**

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<td>0</td>
<td>1000W/m²</td>
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<tr>
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<tr>
<td>600W/m²</td>
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<tr>
<td>400W/m²</td>
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<tr>
<td>200W/m²</td>
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</table>

*For NexTracker installations static loading performance: front load measure 2400Pa, while back load measures 2400Pa.

**Premium Cells, Premium Modules**
GCL-M8/72GDF
Bifacial Dual Glass
Monocrystalline Module
410-435W

435W
Maximum Power Output

19.5%
Maximum Module Efficiency

0~+5W
Power Output Guarantee

GCL Delivers Reliable Performance Over Time

- World-class manufacturer of crystalline silicon photovoltaic modules
- Fully automatic facility and world-class technology
- Tested for harsh environments (salt mist, ammonia corrosion and sand blowing test: IEC 61701, IEC 67716, DIN EN 60068-7-68)
- Long term reliability tests
- 2×100% EL inspection ensuring defect-free modules

Linear Performance Warranty

- 12 Years Product Warranty
- 30 Years Linear Power Warranty

Additional Insurance Backed by Swiss RE

* Please refer to GCL standard warranty for details

* Please refer to GCL for details

Additional choice for large scale ground installation
More evenly distributed soldering points and better reliability and lower hot spot risk
Selected encapsulating material and stringent production process control ensure the product is highly PID resistant and snail trails free
Withstand up to 1500V system voltage effectively reduce BOS cost
Sand blowing test, salt mist test and ammonia test passed to endure harsh environments

Additional safety, Fire class Acertified

1500V

Attachment 3

Preliminary
**Attachment 3**

### Electrical Specification (STC*)

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<thead>
<tr>
<th>Test Condition</th>
<th>Front</th>
<th>Rear</th>
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<tr>
<td>Maximum Power Current</td>
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<tr>
<td>Open Circuit Voltage</td>
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<td>46</td>
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<tr>
<td>Short Circuit Current</td>
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<td>10</td>
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<tr>
<td>Module Efficiency</td>
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<td>18.6</td>
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<tr>
<td>Power Output Tolerance</td>
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</table>

* Irradiance 1000W/m², Module Temperature 25°C, Air Mass 1.5

### Electrical Specification (NOCT*)

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<th>Test Condition</th>
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<td>507.96</td>
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<tr>
<td>Maximum Power Voltage</td>
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<td>36</td>
</tr>
<tr>
<td>Maximum Power Current</td>
<td>8.37</td>
<td>8.37</td>
</tr>
<tr>
<td>Open Circuit Voltage</td>
<td>43.50</td>
<td>43.50</td>
</tr>
<tr>
<td>Short Circuit Current</td>
<td>8.86</td>
<td>8.86</td>
</tr>
</tbody>
</table>

* Irradiance 800W/m², Ambient Temperature 40°C, Wind Speed 1m/s

### Mechanical Data

- Number of Cells: 144 Cells (6x24)
- Dimensions of Module L*W*H (mm): 2130x1048x30mm (83.8x41.2x1.2 inches)
- Weight: 27.5 kg
- Front Side Glass: High transparency solar glass 2.0mm [0.08 inches]
- Back Side Glass: High transparency solar glass 2.0mm [0.08 inches]
- Frame: Silver, anodised aluminium alloy
- IP68 Rated
- Cable: 4.0mm² [0.056 inches²], Portrait 200/200mm (7.87 inches)
- Number of diodes: 3
- Wind/ Snow Load: 2400Pa/5400Pa*
- Connector: MC Compatible

* For more details please check the installation manual of GCLSI

### Temperature Ratings

- Nominal Operating Cell Temperature (NOCT): 43±2°C
- Temperature Coefficient of Voc: -0.3%/°C
- Temperature Coefficient of Isc: -0.2%/°C
- Temperature Coefficient of Pmax: -0.3%/°C

### Maximum Ratings

- Operational Temperature: -40~+85°C
- Maximum System Voltage: 1500V DC
- Max Series Fuse Rating: 20A

### Packaging Configuration

- Module per box: 24 pieces
- Module per 40” container: 520 pieces

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website: [www.gclsi.com](http://www.gclsi.com)  email: gclsisales@gclsi.com

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February 25, 2020

Agenda

Discussion of Applicant’s DPO comments
A. Specific Comments/Proposed Revisions
B. Decommissioning
C. Project Phasing
D. Conclusion

Specific Comments & Proposed Revisions

- Construction Start Date
- Revegetation Success Criteria
- Evidence of Organizational Experience
- Clarification of Stream Setback
- Wildlife Monitoring Plan Limitations
- Weed Control Plan
- Habitat Mitigation Plan
- Land Use Permits and Comp Plan Amendment

Decommissioning

Applicant’s proposal:
1) Calculate the estimate decommissioning and site restoration costs based on final design.
2) At start of construction, post the full amount of the restoration cost estimate.
3) At COD, reduce the posted financial assurance to $1.
4) At year 20, or earlier of the facility’s PPA is terminated early, post the full financial assurance minus scrape value for the remaining life of the facility.
5) Enter into a security interested agreement with EFSC/DOE prior to construction granting EFSC/DOE a priority security interest in the scrap value to ensure “first in line” access ahead of other creditors.
Decommissioning

Variations of Applicant’s Proposal:
EFSC can choose other variations to address perceived risks
1) Approve varying % of estimated scrap value.
2) Upon proof of PPA term, decommissioning security can be required concurrent with the expiration of the PPA.
3) EFSC can delay security until end of useful life of the facility.
4) EFSC can require less than the full cost of decommissioning any time prior to the end of the useful life or PPA term.

Decommissioning

Reasons to accept the Applicant’s proposal.
• Manufacturer’s guarantee useful life of equipment
  ▪ Solar Modules Linear Degradation Rate = 0.05% annually. Efficiency rate ~83% after 25 years.
  ▪ Performance Warranty for 25 to 30 years.
  ▪ Wind Turbines: Turbine OEM model for a 25+ year life (with O&M assumptions)
• Newly built projects are unlikely to be abandoned
  ▪ Wind Projects in the Tehachapi, Altamont, and San Gorgonio Passes have been operating for over 30+
  ▪ Projects are being decommissioned or repowered, but not abandoned. They still have value @30+ yrs

Decommissioning

Executed PPAs provide ample incentive for project owners to continue to operate during the PPA term.
• PPAs are a contractual obligation to deliver power to the customer, typically for 15-25 years.
• A project’s PPA rate and term are embedded in the project’s economics and necessary for construction approval.
• Typical PPAs require operational security during the PPA Term.
  ▪ Average Avangrid Operational PPA security $62k/MW (54M BO)
• Public resources (Dept of Energy, various industry market reports) support term typical terms in PPAs.
• Some executed PPAs are publicly disclosed. (Ex. NV Energy: Gemini PPA $68M in operational security)

Decommissioning

Reasons to accept the Applicant’s proposal (cont’d)
• Renewable energy projects are in high demand
• Repowering is highly probable at the later years extending the operational life of a project (Ex Stateline & Klondike II)
• There is no precedent of an EFSC project being abandoned in the history of projects. (Ex. Stateline, Trojan)
• In the unlikely case of bankruptcy assets will be sold and continue to operate (Ex. Sun Edison/Brookfield acquisition)
• Avangrid has the financial strength to operate the facility.
• ODOE staff has recommended delay in posting B2H security until year 51 and not the full amount.
• IPP PPA vs Rate-basing utility ownership
• Scrap Value
Project Phasing

- Bakeoven Solar will be constructed in phases over time.

<table>
<thead>
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<th>Phase</th>
<th>Size</th>
<th>Year</th>
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</thead>
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<tr>
<td>1</td>
<td>60 MW</td>
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<tr>
<td>2</td>
<td>140 MW</td>
<td>2022</td>
</tr>
<tr>
<td>3</td>
<td>100 MW</td>
<td>2023/2024</td>
</tr>
</tbody>
</table>

- Certificate Holder may seek to “split” site certificate by phase at a future time.

Questions?
Sarah,

I am attaching Avangrid Renewables presentation for tonight’s hearing. I am offering the other points of reference below supportive of our decommissioning information.

Linked below is that Gemini PPA I was referencing. Their Dev Security is $26.75m, stepping up to $74.9m upon PUCN approval. Their Op Security is $68m. If you scroll down to pdf page 189 you’ll find them.


I also found this article from Stoel that might be very handy to reference...look at bullet #3 “Credit Support”


In fact, it is only the rare offtaker that does not insist that the seller provide substantial security for its obligations under the PPA.

There is no universal standard for the amount of security that is required to be posted. In most PPAs, the security is divided into construction period security and security from and after the date the solar plant achieves commercial operation

2018 Wind Technology Report

Hi all,

Please find the attached comment letter received on BSP DPO from Wasco County Planning Department.

Thanks,
Sarah
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====================================================================
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Contributing authors include: Galen Barbose, Naïm Darghouth, Ben Hoen, Andrew Mills, Joe Rand, Dev Millstein, and Seongeun Jeong (Lawrence Berkeley National Laboratory); Kevin Porter and Nicholas Disanti (Exeter Associates); and Frank Oteri (National Renewable Energy Laboratory).
Acknowledgments

For their support of this ongoing report series, the authors thank the entire U.S. Department of Energy (DOE) Wind Energy Technologies Office team. In particular, we wish to acknowledge Patrick Gilman, Rich Tusing, and Valerie Reed. For reviewing elements of this report or providing key input, we also acknowledge: Andrew David (U.S. International Trade Commission); Mike O’Sullivan and Mark Ahlstrom (NextEra); Christopher Namovicz and Richard Bowers (Energy Information Administration); Karin Ohlenforst (Global Wind Energy Council); Lawrence Willey (University of Wyoming); John Hensley and Adam Stern (American Wind Energy Association); and Liz Hartman, Elizabeth Hogan, and Gage Reber (DOE). For providing data that underlie aspects of this report, we thank the Energy Information Administration, Bloomberg New Energy Finance, Wood Mackenzie, Navigant, Global Wind Energy Council, and the American Wind Energy Association. Thanks also to Donna Heimiller and Billy Roberts (NREL) for assistance with the wind project and wind manufacturing maps as well as for assistance in mapping wind resource quality; and Carol Laurie (NREL) and Liz Hartman (DOE) for assistance with layout, formatting, production, and/or communications. Lawrence Berkeley National Laboratory’s contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the DOE under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.
List of Acronyms

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<tr>
<th>Acronym</th>
<th>Full Form</th>
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<tr>
<td>AWEA</td>
<td>American Wind Energy Association</td>
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<td>California Independent System Operator</td>
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<td>COD</td>
<td>commercial operation date</td>
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<td>community choice aggregator</td>
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<td>EDP Renováveis</td>
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<td>GigaWatt</td>
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<td>HTS</td>
<td>Harmonized Tariff Schedule</td>
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<td>independent power producer</td>
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<td>Regional Transmission Organization</td>
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<td>Siemens Gamesa Renewable Energy</td>
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<td>United States Wind Turbine Database</td>
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<td>Western Area Power Administration</td>
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<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
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Executive Summary

Wind power capacity in the United States continued to grow robustly in 2018, supported by the industry’s primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Improvements in the cost and performance of wind power technologies have also driven wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. The magnitude of growth beyond the current PTC cycle remains uncertain, however, given declining tax support, expectations for low natural gas prices, and modest electricity demand growth.

Key findings from this year’s Wind Technologies Market Report—which primarily focuses on land-based, utility-scale wind—include:

installation trends

- Wind power continued at a robust pace in 2018, with 7,588 MW of new capacity added in the United States and $11 billion invested. Supported by favorable tax policy and other factors, cumulative wind power capacity grew to 96,433 MegaWatts (MW). In addition to this newly installed capacity, 1,312 MW of partial wind plant repowering was completed in 2018, mostly involving upgrades to the rotor diameters and major nacelle components of existing turbines in order to access favorable tax incentives, increase energy production with more-advanced technology, and extend project life.

- Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2018, behind solar and natural gas. Wind power constituted 21% of all capacity additions in 2018. Over the last decade, wind represented 28% of all U.S. capacity additions, and an even larger fraction of new capacity in the Interior (56%) and Great Lakes (40%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the West (18%) and Northeast (13%), and considerably less in the Southeast (1%). [See Figure 1 for regional definitions].

- Globally, the United States ranked second in annual wind capacity additions in 2018, but was well behind the market leaders in wind energy penetration. Global wind additions equaled 50,100 MW in 2018, yielding a cumulative total of approximately 590,000 MW. The United States remained the second-leading market in terms of annual and cumulative capacity as well as annual wind generation, behind China. A number of countries have achieved high levels of wind penetration, with wind supplying over 40% of Denmark’s total electricity generation in 2018, and between 20% and 30% in Ireland, Portugal and Germany. In the United States, wind supplied 6.5% of total electricity generation in 2018.

- Texas installed the most capacity in 2018 with 2,359 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation. New utility-scale wind turbines were installed in 20 states in 2018. On a cumulative basis, Texas remained the clear leader, with 24,895 MW of capacity. Notably, the wind capacity installed in Oklahoma, Iowa, and Kansas supplied 31%–36% of all in-state electricity generation in 2018. Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2018, wind penetration (expressed as a percentage of load) was 23.9% in the Southwest Power Pool (SPP), 18.6% in the Electric Reliability Council of Texas (ERCOT), 7.3% in both the Midcontinent Independent System Operator (MISO) and the California Independent System Operator (CAISO), 2.8% in ISO New England (ISO-NE), 2.7% in the PJM Interconnection (PJM), and 2.5% in the New York Independent System Operator (NYISO).

- A record level of wind power capacity entered transmission interconnection queues in 2018; solar and storage also reached new highs in 2018. At the end of 2018, there was 232 GigaWatts (GW) of wind capacity seeking transmission interconnection, representing 36% of all generating capacity in the reviewed queues. In 2018, 92 GW of wind capacity entered interconnection queues, second only to solar capacity additions. Energy storage interconnection requests have also increased in recent years, both for
stand-alone storage and hybrid plants, most-often pairing solar with storage. The Southwest Power Pool, Mountain, and Midwest regions had the greatest quantity of wind in their queues at the end of 2018.

Industry Trends

- **GE and Vestas accounted for 78% of the U.S. wind power market in 2018.** In 2018, GE captured 40% of the U.S. market for turbine installations, edging out Vestas at 38% and followed at a distance by Nordex at 11% and Siemens-Gamesa Renewable Energy (SGRE) at 8%. Vestas was the leading turbine supplier for wind installations worldwide in 2018, followed by Goldwind, SGRE, and GE.

- **The domestic wind industry supply chain was reasonably stable in 2018.** The domestic supply chain for wind equipment faces conflicting pressures, including significant near-term growth, but also strong competitive pressures and an anticipation of reduced demand in the medium term as the PTC is phased out. Domestic wind sector employment reached a new high of 114,000 full-time workers. Although there have been a number of plant closures in recent years, three major turbine manufacturers have domestic manufacturing facilities. Domestic nacelle assembly capability stood at a record 15 GW in 2018, and the United States had the capability to produce blades and towers sufficient for approximately 9.2 GW and 8.9 GW, respectively, of wind capacity annually.

- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports.** The United States is reliant on imports of wind equipment from a wide array of countries, with the level of dependence varying by component. Domestic manufacturing content is highest for nacelle assembly (>85%), towers (75%–90%), and blades and hubs (50%–70%).

- **The project finance environment remained strong in 2018.** Initial concerns over the potential negative impact of the Tax Cuts and Jobs Act on wind project finance in the United States—and on tax equity supply in particular—proved to be largely unfounded. The U.S. wind market raised $6–7 billion of new tax equity in 2018, on par with the four prior years. Tax equity yields declined to around 7% (in unlevered, after-tax terms), while the cost of term debt initially increased, but then returned to around 4% toward the end of 2018. Looking ahead, 2019 and 2020 should continue to be active, given the abundant backlog of turbines that met safe-harbor requirements to qualify for 100% PTC. Post 2020, another reported 10 GW of safe-harbor turbines are available at the 80% PTC, with 6.6 GW of 60% PTC-qualified equipment. Given the safe harbor window in which to bring projects online, these 80%- and 60%-PTC projects might be expected to be online by the end of 2021 and 2022, respectively.

- **Independent power producers own the majority of wind assets built in 2018.** Independent power producers (IPPs) own 80% of the new wind capacity installed in the United States in 2018, with the remaining assets owned by investor-owned utilities (19.9%) and other entities (0.1%).

- **Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant.** Electric utilities continued to be the largest off-takers of wind power in 2018, either owning wind projects (20%) or buying electricity from projects (27%) that, in total, represent 47% of the new capacity installed in 2018. Direct retail purchasers—including corporate off-takers—account for 24%. Merchant/quasi-merchant projects (23%) and power marketers (3%) make up the remainder (with 3% undisclosed).

Technology Trends

- **Average turbine capacity, rotor diameter, and hub height increased in 2018, continuing the long-term trend.** To optimize wind project cost and performance, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2018 was 2.43 MW, up 5% from the previous year and 239% since 1998–1999. The average rotor diameter in 2018 was 115.6 meters, a 2% increase over 2017 and 141% over 1998–1999, while the average hub height in 2018 was 88.1 meters, up 2% over the previous year and 57% since 1998–1999.

- **Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades.** Rotor scaling has been especially significant in recent years. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; in contrast, by
2018, 99% of newly installed turbines featured rotors of at least that diameter. In fact, 87% of newly installed turbines in 2018 featured rotor diameters of greater than or equal to 110 meters, with 30% of turbines having rotors greater than or equal to 120 meters.

- **Turbines originally designed for lower wind speed sites dominate the market, and are being deployed in a range of wind resource conditions.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average “specific power” \(^1\) (in W/m\(^2\)), from 395 W/m\(^2\) among projects installed in 1998–1999 to 230 W/m\(^2\) among projects installed in 2018. The trend toward lower specific power machines slowed in 2018. In general, turbines with low specific power were originally designed for lower wind speed sites.

- **Wind turbines continued to be deployed in somewhat lower wind-speed sites.** Wind turbines installed in 2018 were located in sites with an average estimated long-term wind speed of 7.8 meters per second at a height of 80 meters above the ground. These sites have lower wind speeds than those chosen for deployment in the 2014–2016 period, but they are similar to 2017 and have higher wind speeds than where turbines were installed from 2009 to 2013. Federal Aviation Administration (FAA) data suggest that near-future wind projects will be located in similar wind resource areas as those installed in 2018.

- **Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers are more commonly found in the Great Lakes and Northeast.** Low specific power turbines continue to be deployed in all regions of the United States, and at both lower and higher wind speed sites. The tallest towers (i.e., those above 100 meters) are found in greater relative frequency in the Great Lakes and Northeastern regions and in lower wind speed sites.

- **Wind projects planned for the near future continue the trend of ever-taller turbines.** FAA permit data suggest that near-future wind projects will deploy even taller turbines, with a significant portion (44%) of permit applications in early 2019 over 500 feet (152 meters), whereas the average total height for turbines installed in 2018 was 479 feet (146 meters).

- **The number of wind power projects that employed multiple turbine configurations from a single turbine supplier continued to increase.** More than a third of the larger wind projects built in 2018 utilized turbines with multiple hub heights, rotor diameters, and/or capacities—all supplied by the same original equipment manufacturer (OEM). This development primarily reflects efforts to qualify projects for the full PTC by purchasing the minimum required number of turbines prior to the end of 2016, but may also reflect increasing sophistication with respect to turbine siting and wake effects, coupled with an increasing willingness among turbine suppliers to provide multiple turbine configurations, leading to increased site optimization.

- **Through 2018, twenty-three wind projects have been partially repowered, most of which now feature significantly larger rotors and lower specific power ratings.** From 2017 through 2018, 23 projects were partially repowered, encompassing 2,425 turbines and totaling 3,445 MW before repowering. Of the changes made to these turbines, larger rotors dominated, increasing the average rotor diameter by 8.1 meters, while reducing specific power by 16%, from 357 to 301 W/m\(^2\). The primary motivation for partial repowering has been to re-qualify for the PTC, while at the same time improving operational performance and extending the useful life of the projects.

**Performance Trends**

- **The average capacity factor in 2018 exceeded 40% among wind projects built in recent years, and reached 35% on a fleet-wide basis.** The average 2018 capacity factor among projects built from 2014 to 2017 was 41.9%, compared to an average of 30.8% among all projects built from 2004 to 2011, and 23.8% among all projects built from 1998 to 2001. This apparent improvement among more-recently

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\(^1\) A wind turbine’s specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.
built projects has slowly pushed the cumulative fleet-wide capacity factor higher over time, reaching 35% for the first time in 2018.

- **Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology.** Based on a sub-sample of wind projects built in 2014–2017, average capacity factors in 2018 were highest in the Interior region (43.1%) and lowest in the Northeast (31.3%). Not surprisingly, the regional rankings are roughly consistent with the relative quality of the wind resource in each region. However, they also reflect the degree to which each region has adopted turbines with lower specific power and/or taller towers. For example, the Great Lakes region has thus far adopted these new designs (particularly taller towers) to a larger extent than some other regions, leading to an increase in average regional capacity factors.

- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor.** The decline in specific power has been a major contributor to higher capacity factors, but has been offset to a degree by a tendency—especially from 2009 to 2012, when a cash grant was available in lieu of the PTC—toward building projects at lower-quality wind sites. Controlling for these two influences shows that turbine design changes are driving capacity factors significantly higher over time among projects located in given wind resource regimes.

- **Wind curtailment can differentially impact project performance across sites and regions.** Across all independent system operators (ISOs), wind energy curtailment in 2018 remained modest at around 2.2%. This average, however, masks variation across regions, and even more so by project—e.g., the average curtailment within ERCOT was 2.5% in 2018, but four wind projects totaling nearly 600 MW experienced curtailment of 18–25%. The amount of curtailment is not necessarily directly related to wind energy penetration within a region, as SPP and ERCOT have by far the highest penetration rates but less curtailment than in some other regions with lower penetration rates. Sample-wide capacity factors in 2018 would have been 0.7 percentage points higher nationwide absent curtailment in the ISOs.

- **Temporal variations in wind speed also impact performance.** The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. But for the third year in a row, wind speeds across the continental United States in 2018 were generally close to their long-term averages, both within each region and on average across all regions.

- **Wind project performance degradation may also explain why older projects did not perform as well in 2018.** Capacity factor data suggest some amount of performance degradation, though perhaps only once projects age beyond 9 or 10 years. Though the cause is somewhat uncertain, the apparent decline in capacity factors as projects progress into their second decade could partially explain why older projects—e.g., those built from 1998 to 2001—did not perform as well as newer projects in 2018.

### Cost Trends

- **Wind turbine prices remained well below levels seen a decade ago.** After hitting a low of roughly $800 per kilowatt (kW) from 2000 to 2002, average turbine prices increased to more than $1,600/kW by 2008. Since then, wind turbine prices have steeply declined, despite increases in size. Recent data suggest pricing most-typically in the $700–$900/kW range. These price reductions, coupled with improved turbine technology, have exerted downward pressure on project costs and wind power prices.

- **Lower turbine prices have driven reductions in reported installed project costs.** The capacity-weighted average installed project cost within our 2018 sample stood at $1,470/kW. This is a decrease of nearly $1,000/kW from the peak in average costs in 2009 and 2010, but is roughly on par with the costs experienced in the early 2000s—albeit with much larger turbines and improved performance. Early

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2 All cost figures presented in the report are denominated in real 2018 dollars.
indications from a sample of projects currently under construction suggest that somewhat lower costs are on the horizon, with some developers reporting costs in the $1,100–$1,250/kW range.

- **Installed costs differed by project size and turbine size.** Installed project costs for plants built in 2018 exhibit economies of scale, with costs declining as project size increases, at least at the lower end of the project size range.

- **Installed costs differed by region.** Among projects built in 2018, the Interior of the country was the lowest-cost region, with a capacity-weighted average cost of $1,400/kW. The number of projects installed in 2018 in other regions is limited, but those projects tended to experience higher installed costs, with an average of $1,740/kW; the Northeast was the highest-cost region.

- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, projects installed over the past decade have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first several years of operation. The data suggest that O&M costs have increased as projects age for the older projects in the sample, but generally hold steady with age among those projects installed over the last decade.

### Wind Power Price Trends

- **Wind power purchase agreement prices are at historical lows.** After topping out above $70 per MegaWatt-hour (MWh) for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to below $20/MWh—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from around $57/MWh among contracts executed in 2009 to below $20/MWh in 2017 and 2018. Today’s low PPA prices have been facilitated by the combination of higher capacity factors, declining installed costs and operating costs, and low interest rates documented elsewhere in this report; the PTC has also been a key enabler over time.

- **Recent wind power purchase agreements have been priced in the mid-teens in some cases.** There are a growing number of sub-$20/MWh PPAs. Within our full PPA sample there are 16 projects (all in the Interior region) with levelized pricing below $20/MWh. This subset totals 2,468 MW and sells its output through 22 different PPAs signed since early 2015. The levelized prices of these 22 PPAs range from $9.3/MWh to $19.7/MWh.

- **Despite ultra-low PPA prices, wind faces stiff competition from solar and gas.** The once-wide gap between wind and solar PPA prices has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices. With the support of federal tax incentives, both wind and solar PPA prices are now below the projected cost of burning natural gas in existing gas-fired combined cycle units.

- **The economic competitiveness of wind energy is in part dictated by its grid-system value in wholesale power markets.** Given the location of wind projects and the hourly profile of wind generation, the average wholesale market value of wind has generally declined over the last decade. However, there has been a modest rebound in wind’s wholesale market value over the last two years. Following the sharp drop in wholesale electricity prices (and, hence, wind energy market value) in 2009, average wind PPA prices tended to exceed the wholesale market value of wind through 2012. Continued declines in wind PPA prices brought those prices back in line with the market value of wind in 2013, and wind has generally remained competitive in subsequent years. The market value of wind in 2018 was the lowest in SPP, at $17/MWh, whereas the highest-value market was ISO-NE at $41/MWh.

- **PPA price trends reflect the levelized cost of wind energy.** Regional and nationwide trends in the levelized cost of wind energy (LCOE) closely follow the PPA trends described above—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2018. The lowest LCOEs are found in the Interior region, with an average of $34/MWh for those projects built in 2018, and with
some projects as low as $27/MWh. The national average LCOE of wind project built in 2018 was at an all-time low of $36/MWh. These LCOE estimates exclude the PTC and any state-level incentives.

**Policy and Market Drivers**

- **The federal production tax credit remains one of the core motivators for wind power deployment.** In 2015, Congress passed a five-year extension of the PTC that provides the full PTC to projects that started construction prior to the end of 2016, but that phases out the PTC for projects starting construction in subsequent years (e.g., projects that started construction in 2017 get 80% of the PTC, dropping to 60% and 40% for projects starting construction in 2018 and 2019, respectively). In 2016, the IRS issued Notice 2016-31, allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. According to various sources, 30–70 GW of wind turbine capacity had been qualified for the full PTC by the end of 2016 (presuming commercial operations is achieved by the end of 2020), with another 10 GW qualifying for the 80% PTC (if online prior to the end of 2021) and 6.6 GW for the 60% PTC (if online by the end of 2022).

- **State policies help direct the location and amount of wind power development, but wind power growth is outpacing state targets.** As of May 2019, renewables portfolio standards (RPS) existed in 29 states and Washington, D.C. Of all wind capacity built in the United States from 2000 through 2018, roughly 47% is serving RPS obligations. Among wind projects built in 2018, however, this proportion fell to 19%. Existing RPS programs are projected to require average annual renewable capacity additions of roughly 5 GW/year through 2030.

- **System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that the cost of integrating wind energy into the grid is often below $5/MWh for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. Grid system operators and others continue to implement a range of methods to accommodate increased wind energy penetrations. Transmission additions were limited in 2018, with approximately 1,300 miles of transmission lines coming online. The wind industry has identified 27 near-term transmission projects that, if completed, could support considerable amounts of wind capacity.

**Future Outlook**

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next couple years, before declining, driven by the five-year phased expiration of the PTC. Additionally, improvements in the cost and performance of wind power technologies, which contribute to low power sales prices, will impact near-term additions. Other factors positively influencing demand include corporate wind energy purchases and state-level renewable energy policies. As a result, various forecasts show wind capacity additions increasing in the near term, to 9–12 GW in 2019 and 11–15 GW in 2020. Forecasts for 2021 to 2028, on the other hand, show a downturn, in part due to the PTC phase-out. Expectations for continued low natural gas prices and modest electricity demand growth also put a damper on growth expectations, as do limited transmission infrastructure and competition from natural gas and—increasingly—solar energy. At the same time, the potential for continued cost reductions may enhance the prospects for longer-term growth, as might burgeoning corporate demand for wind energy and continued state RPS requirements. Moreover, new transmission in some regions is expected to open up high-quality wind resources for development. Given these diverse and contrasting underlying potential trends, wind additions—especially after 2020—remain uncertain.
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1 Introduction

Wind power capacity additions in the United States continued at a robust pace in 2018. Recent and projected near-term growth is supported by the industry’s primary federal incentive—the production tax credit (PTC)—having been extended (with a phase-out schedule) through 2019 as well as a myriad of state-level policies. Continued improvements in the cost and performance of wind power technologies have also driven wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. At the same time, the magnitude of growth beyond the current PTC cycle remains uncertain, given declining federal tax support, expectations for continued low natural gas prices, increasing competition from solar, and modest electricity demand growth.

This annual report—now in its thirteenth consecutive year—provides an overview of developments and trends in the U.S. wind power market, with a particular focus on the year 2018. The report begins with an overview of installation-related trends: U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual U.S. states; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into and exports from the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine size, hub height, rotor diameter, specific power, and International Electrotechnical Commission (IEC) Class. After that, the report discusses wind power performance, cost, and pricing. In doing so, it describes trends in project-level capacity factors, wind turbine transaction prices, installed project costs, and operations and maintenance (O&M) expenses. It also reviews the prices paid for wind power through power purchase agreements (PPAs) and how those prices compare to the value of wind generation in wholesale energy markets as well as forecasts of future natural gas prices. Next, the report examines market and policy factors impacting the domestic wind industry, including federal and state policy as well as transmission and grid integration issues. The report concludes with a preview of possible near-term market developments based on the findings of other energy analysts.

Many of these trends vary by state or region, depending in part on the strength of the local wind resource. To that end, Figure 1 superimposes the boundaries of five broad regions on a map of average annual U.S. wind speed at 80 meters above the ground. These five regions will be referenced on many occasions throughout this report, whenever regional breakdowns or analysis is warranted, so they are defined here. Note that any such breakdowns, regional or otherwise, may not always add up to 100% due to rounding.

This edition of the annual report updates data presented in previous editions while highlighting trends and new developments that were observed in 2018. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that exceed 100 kW in size. The U.S. wind power sector is multifaceted, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on distributed wind power, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S.

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3 The regional boundaries shown in Figure 1 have been delineated in an attempt to simultaneously satisfy three goals: have a relative uniformity in average annual wind speed within each individual region, include enough states in each region to enable sufficient wind project sample size for regional breakdowns and analysis, and adhere as closely as possible to traditional regional boundaries.

4 This 100-kW threshold between “smaller” and “larger” wind turbines is applied starting with 2011 projects to better match the American Wind Energy Association’s historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match AWEA’s reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.
Department of Energy (DOE)—the 2018 Distributed Wind Market Report.\(^5\) Additionally, because this report has a historical focus—and because only one offshore wind project is operational in the United States—this report does not address trends in offshore wind power. A companion study funded by DOE that focuses exclusively on offshore wind power is also available—the 2018 Offshore Wind Technologies Market Report.\(^6\)

![Regional boundaries overlaid on a map of average annual wind speed at 80 meters](https://energy.gov/eere/wind/downloads/2018-distributed-wind-market-report)

**Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 80 meters**

Much of the data included in this report were compiled by DOE’s Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Wind Energy Association (AWEA). The Appendix provides a summary of the many data sources. In some cases, the data shown represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. Emphasis should therefore be placed on overall trends, rather than on individual data points. Finally, each section of this report primarily focuses on historical and recent data. With some limited exceptions—including the final section of the report—the report does not seek to forecast wind energy trends.

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2 Installation Trends

Wind power additions continued at a robust pace in 2018, with 7,588 MW of new capacity added in the United States and $11 billion invested

U.S. wind power capacity additions equaled 7,588 MW in 2018, up slightly from 2017 additions and bringing the cumulative total to 96,433 MW (Figure 2). This growth represented $11 billion of investment in new wind power project installations in 2018, for a cumulative investment total of roughly $196 billion since the beginning of the 1980s. Over 80% of the new wind power capacity installed in 2018 is located within the Interior region (as defined in Figure 1).

A new trend is that of partial wind project repowering, in which major components of turbines are replaced in order to access favorable tax incentives, increase energy production with more-advanced turbine technology, and extend project life. In addition to the newly installed wind capacity reported above, 1,312 MW of partial repowerings were completed in 2018 across 10 projects, down from the 2,133 MW of partial repowering across 13 projects completed in 2017. Upgrades and refurbishments often lead to increased rotor diameters and the replacement of major nacelle components, with fewer changes to tower heights and nameplate capacity.

As in previous years, growth was driven in part by continued improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand also played a role.

Figure 2. Annual and cumulative growth in U.S. wind power capacity

As in previous years, growth was driven in part by continued improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand also played a role.

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7 When reporting annual wind power capacity additions, this report focuses on gross capacity additions, and does not consider partial repowering. The net increase in capacity each year can be somewhat lower, reflecting turbine decommissioning, or higher, reflecting partial repowering that increases nameplate capacities. Reported cumulative capacity does include both decommissioning and repowering.

8 All cost and price data are reported in real 2018 dollars.

9 These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

10 The 1,312 MW and 2,133 MW of partially repowered capacity reflect the initial capacity, prior to refurbishment. Any change in capacity from partial repowering is included in the cumulative data but not the annual data reported in Figure 2.
A crucial factor was the PTC, which, in December 2015, was extended for an additional five years—applying to projects that begin construction before January 1, 2020, but with a progressive reduction in the value of the credit for projects starting construction after 2016. Meanwhile, the ability of partially repowered wind projects to access the PTC was the primary motivator for the growth in partial repowering in 2017 and 2018.

*Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2018, behind solar and natural gas*

Wind power has comprised a sizable share of generation capacity additions in recent years. In 2018, it constituted 21% of all U.S. capacity additions and was the third-largest source of new capacity, behind solar and natural gas (Figure 3).11 Wind power’s share of overall annual capacity additions declined slightly in 2018 relative to 2017, largely due to a sizable increase in natural gas capacity additions.

![Figure 3. Relative contribution of generation types in annual capacity additions](image)

Over the last decade, wind power represented 28% of total U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (56%) and Great Lakes (40%) regions (Figure 4; see Figure 1 for regional definitions). Wind power’s contribution to generation capacity growth over the last decade is somewhat smaller—but still significant—in the West (18%) and Northeast (13%), and considerably less in the Southeast (1%).

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11 Data presented here are based on gross capacity additions, not considering retirements or partial repowering. Furthermore, they include only the 50 U.S. states, not U.S. territories.
Globally, the United States ranked second in annual wind capacity additions in 2018, but was well behind the market leaders in wind energy penetration

Global wind additions equaled roughly 50,100 MW in 2018: approximately 90% of which was land-based, with the remainder offshore wind. This figure is below the 53,500 MW in 2017 and below the record of 63,800 MW added in 2015. With its 7,588 MW representing 15% of new global installed capacity in 2018, the United States continued to maintain its second-place position behind China (Table 1). Cumulative global capacity grew by nearly 10% and totaled approximately 590,000 MW at the end of the year (GWEC 2019),12 with the United States accounting for 16% of global capacity—a distant second to China by this metric. The United States also remains in second place, behind China, in annual wind electricity generation.

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12 Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2019) but are updated, where necessary, with the U.S. data presented here. Some disagreement exists among these data sources and others.
Table 1. International Rankings of Wind Power Capacity: Land-based and Offshore

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>China</td>
<td>21,855</td>
<td>210,247</td>
</tr>
<tr>
<td>United States</td>
<td>7,588</td>
<td>96,433</td>
</tr>
<tr>
<td>Germany</td>
<td>3,371</td>
<td>59,312</td>
</tr>
<tr>
<td>India</td>
<td>2,191</td>
<td>35,129</td>
</tr>
<tr>
<td>Brazil</td>
<td>1,939</td>
<td>23,531</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>1,901</td>
<td>20,964</td>
</tr>
<tr>
<td>France</td>
<td>1,565</td>
<td>15,309</td>
</tr>
<tr>
<td>Mexico</td>
<td>929</td>
<td>14,707</td>
</tr>
<tr>
<td>Sweden</td>
<td>720</td>
<td>12,816</td>
</tr>
<tr>
<td>Canada</td>
<td>566</td>
<td>9,959</td>
</tr>
<tr>
<td>Rest of World</td>
<td>7,493</td>
<td>91,466</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>50,118</strong></td>
<td><strong>589,872</strong></td>
</tr>
</tbody>
</table>

Sources: GWEC (2019, updated via personal communication); AWEA WindIQ for U.S.

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 5 presents data on a subset of countries, focusing on those with greater levels of total wind power capacity. Wind penetration exceeded 40% in Denmark in 2018, and was between 20% and 30% in Ireland, Portugal, and Germany. In the United States, wind supplied 6.5% of total electricity generation in 2018 (see Table 2 for additional details).
Texas installed the most capacity in 2018 with 2,359 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation

New utility-scale wind turbines were installed in 20 states in 2018. Texas once again installed the most new wind capacity of any state, adding 2,359 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity—included Iowa, Colorado, Oklahoma, Nebraska, Kansas, and Illinois.

On a cumulative basis, Texas remained the clear leader, with 24,895 MW installed at the end of 2018—almost three times as much as the next-highest state (Iowa, with 8,421 MW). In fact, Texas has more wind capacity than all but four countries (including the United States). States distantly following Texas in cumulative installed capacity include Iowa and Oklahoma (both with more than 8,000 MW), as well as California and Kansas (both with more than 5,000 MW). Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2018, with 26 of these above 500 MW, 19 above 1,000 MW, 12 above 2,000 MW, and 11 above 3,000 MW.

![Figure 6. Location of wind power development in the United States](image)

Note: Numbers within states represent MegaWatts of cumulative installed wind capacity and, in brackets, annual additions in 2018.

Some states have reached high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2018 divided by total in-state electricity generation and by in-state electricity sales in 2018. Electric transmission networks enable most states to both import and export power in real time, and states do so in varying amounts. Denominating in-state wind generation as both a proportion of in-state generation and as a proportion of in-state sales is relevant, but both should be viewed with some caution given varying amounts of imports and exports. As a fraction of in-state generation, Kansas leads the list, with 36.4% of electricity generated in the state coming from wind, followed by Iowa, Oklahoma, North Dakota, and South Dakota. As a fraction of in-state sales, North Dakota is the leading state, with 53.5%
of the electricity sold in the state being met by wind, followed by Kansas, Oklahoma, and Iowa (all above 40%). Fourteen states have achieved wind penetration levels of 10% or higher when expressed as a percentage of generation, whereas 15 states have reached this threshold when expressed as a percentage of sales.

### Table 2. U.S. Wind Power Rankings: The Top 20 States

<table>
<thead>
<tr>
<th>State</th>
<th>Installed Capacity (MW)</th>
<th>2018 Wind Generation as a Percentage of:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>In-State Generation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Texas</td>
</tr>
<tr>
<td>Texas</td>
<td>2,359</td>
<td>24,895</td>
</tr>
<tr>
<td>Iowa</td>
<td>1,120</td>
<td>8,421</td>
</tr>
<tr>
<td>Colorado</td>
<td>600</td>
<td>8,072</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>576</td>
<td>5,840</td>
</tr>
<tr>
<td>Nebraska</td>
<td>558</td>
<td>5,653</td>
</tr>
<tr>
<td>Kansas</td>
<td>543</td>
<td>4,861</td>
</tr>
<tr>
<td>Illinois</td>
<td>529</td>
<td>3,778</td>
</tr>
<tr>
<td>California</td>
<td>330</td>
<td>3,703</td>
</tr>
<tr>
<td>Indiana</td>
<td>200</td>
<td>3,213</td>
</tr>
<tr>
<td>New York</td>
<td>158</td>
<td>3,155</td>
</tr>
<tr>
<td>North Dakota</td>
<td>148</td>
<td>3,076</td>
</tr>
<tr>
<td>Ohio</td>
<td>113</td>
<td>2,317</td>
</tr>
<tr>
<td>Montana</td>
<td>105</td>
<td>1,987</td>
</tr>
<tr>
<td>Minnesota</td>
<td>90</td>
<td>1,972</td>
</tr>
<tr>
<td>New Mexico</td>
<td>51</td>
<td>1,904</td>
</tr>
<tr>
<td>Michigan</td>
<td>44</td>
<td>1,732</td>
</tr>
<tr>
<td>South Dakota</td>
<td>41</td>
<td>1,488</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>21</td>
<td>1,369</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>2</td>
<td>1,019</td>
</tr>
<tr>
<td>Alaska</td>
<td>1</td>
<td>973</td>
</tr>
<tr>
<td>Rest of U.S.</td>
<td>0</td>
<td>700</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>7,588</strong></td>
<td><strong>96,433</strong></td>
</tr>
</tbody>
</table>

*Note: Based on 2018 wind and total generation and retail sales by state from EIA’s Electric Power Monthly.*

*Sources: AWEA WindIQ, EIA*

Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2018, wind penetration (expressed as a percentage of load) was 23.9% in the Southwest Power Pool (SPP), 18.6% in the Electric Reliability Council of Texas (ERCOT), 7.3% in both the Midcontinent Independent System Operator (MISO) and the California Independent System Operator (CAISO), 2.8% in ISO New England (ISO-NE), 2.7% in the PJM Interconnection (PJM), and 2.5% in the New York Independent System Operator (NYISO).

**A record level of wind power capacity entered transmission interconnection queues in 2018; solar and storage also reached new highs in 2018**

One testament to the amount of developer and purchaser interest in wind energy is the amount of wind power capacity working its way through the major transmission interconnection queues across the country. Figure 7 provides this information over the last five years for wind power and other resources aggregated across 37 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.¹³ These data should be interpreted with caution: placing a project in the

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¹³ The queues surveyed include PJM, MISO, NYISO, ISO-NE, CAISO, ERCOT, SPP, Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and a large number of other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of over 80% of the U.S. total. Figures 7 and 8 only include projects that were
interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built (often, fewer than 25% of projects are subsequently built).

Even with this important caveat, the amount of wind capacity in the nation’s interconnection queues still provides at least some indication of the amount of planned development. At the end of 2018, there were 232 GW of wind power capacity in the interconnection queues reviewed for this report—a sizable increase from the 180 GW in the same queues just one year earlier and more than at any point since the end of 2011. In fact, a record level of wind power capacity entered interconnection queues in 2018 (at least since 2009, when Berkeley Lab started collecting queue data)—92 GW in total, exceeding the previous record of 81 GW in 2017. Wind was not the only technology to reach a new record in 2018, however, as solar additions outpaced wind, at 133 GW. Storage additions have also increased in recent years. Moreover, for 2018, hybrid plants that include storage are also presented. As shown, 20% of the solar capacity in interconnection queues at the end of 2018 has been proposed as hybrid plants paired with storage, whereas only 2% of the wind capacity is paired with storage. Overall, wind represented 36% of all capacity in the sampled queues, compared to 44% for solar, 13% for natural gas, and 4% for stand-alone storage.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with the largest amounts in SPP (25%), the Mountain region (16%), the Midwest (16%), ERCOT (11%), and PJM (10%). Smaller amounts are found in the Northwest (7%), ISO-NE (7%), NYISO (6%), and California (3%), with the Southeast currently having no wind projects in the sampled queues. The PJM, Mountain, and Midwest regions experienced especially large annual additions in 2018.
As additional measures of the near-term development pipeline, ABB (2019) estimates that, as of May 2019, approximately 49 GW of wind power capacity could be characterized in one of three ways: (a) under construction or in site preparation (10 GW); (b) in development and permitted (16 GW); or (c) in development with a pending permit and/or regulatory applications (23 GW). These totals are approximately 10 GW higher than at the same time last year. AWEA (2019b) reports that more than 39 GW of wind power capacity was under construction or at an advanced stage of development at the end of the first quarter of 2019. EIA (2019b) identifies nearly 22 GW of planned additions for 2019 and 2020 combined.
3 Industry Trends

**GE and Vestas accounted for 78% of the U.S. wind power market in 2018**

Of the 7,588 MW of wind installed in 2018, GE Wind supplied 40% (3,011 MW), with Vestas coming in second (2,886 MW, 38% market share), followed more distantly by Nordex (866 MW, 11% market share) and Siemens Gamesa Renewable Energy (SGRE, 630 MW, 8% market share) (Figure 9). Of the 7,588 MW of wind installed in 2018, GE Wind supplied 40% (3,011 MW), with Vestas coming in second (2,886 MW, 38% market share), followed more distantly by Nordex (866 MW, 11% market share) and Siemens Gamesa Renewable Energy (SGRE, 630 MW, 8% market share) (Figure 9). Other suppliers included Goldwind (171 MW), Vensys (23 MW), and Emergya Wind Technologies (1 MW). GE and Vestas have dominated the U.S. market for some time, with SGRE and—more recently—Nordex vying for third.

![Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2018](image)

The black line in Figure 9 shows the number of turbine manufacturers serving more than 1% (by capacity) of the U.S. market in each year. As shown, the base of turbine suppliers expanded from just four original equipment manufacturers (OEMs) in 2005 to nine from 2008 to 2011 and twelve in 2012. Since 2012, however, the U.S. turbine market has been dominated by just a handful of OEMs—a trend that may continue in the future due to consolidation among OEMs. For example, the Nordex/Acciona merger took effect in April 2016 (in Figure 9, their combined operations are reported starting in 2016), while Siemens Wind Power and Gamesa consolidated their operations in April 2017 (and are combined in Figure 9 starting in 2017).

According to the Global Wind Energy Council (GWEC), Vestas was the leading supplier of turbines worldwide in 2018, followed by Goldwind, SGRE, and GE. On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with eight of the top fifteen spots in the ranking. To date, however, the growth of Chinese turbine manufacturers has been primarily based on sales to the Chinese market. GE is the only U.S.-based utility-scale turbine manufacturer playing a role in the global supply of large wind turbines.

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14 Market share is reported in MW terms and is based on project installations in the year in question.
The domestic wind industry supply chain was reasonably stable in 2018

The wind industry’s domestic supply chain continues to deal with conflicting pressures: a surge in near-term expected growth from new installations and partial repowering, but also strong competitive pressures and expected reduced demand in the medium-term as the PTC is phased out. As a result, though some manufacturers increased the size of their U.S. workforce in 2018, overall growth has moderated.

Figure 10 presents a non-exhaustive list of approximately 140 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2018, focusing on the utility-scale wind market. Figure 11 segments those facilities by the type of component they primarily supply.

No new wind-related manufacturing facilities opened in 2018, as illustrated in Figure 11. However, two new facilities were announced and are expected to be online by the end of 2019. In August 2018, Betz Industries announced plans to build a new facility in Michigan near the company’s existing headquarters that will manufacture iron castings for multiple industries including wind energy. The facility is expected to open in 2019 and employ up to 45 workers at full capacity. Additionally, RMC Advanced Technologies—a subsidiary of Sigma Industries—announced the acquisition of a new facility in Tennessee that will produce composite parts used by the wind energy industry. The facility is expected to open in 2019 and employ 50 when operating.

The data on manufacturing facilities presented here differ from those presented in AWEA (2019a) due, in part, to methodological differences. For example, AWEA includes data on a large number of smaller component suppliers that are not included in this report; the figure presented here also does not include research and development and logistics centers, or material suppliers. As a result, AWEA (2019a) reports a much larger number of wind-related manufacturing facilities.
at capacity. Meanwhile, at least four existing wind turbine or component manufacturing facilities were consolidated, closed, or stopped serving the industry in 2018 (The Gear Works, Creative Foam, Danfoss Drives, and ZF). In addition, in late 2017, MFG Wind announced that it would be closing its blade manufacturing facility in Aberdeen, South Dakota, though the company has since adjusted the timeframe for the closure and will keep the facility open through 2020.

![Number of wind turbine and component manufacturing facilities in the United States](image)

**Figure 11. Number of wind turbine and component manufacturing facilities in the United States**

Notwithstanding the recent supply chain consolidation and slow additions of new facilities, there remain a large number of domestic manufacturing facilities. Additionally, multiple manufacturers either expanded their workforce in 2018 to meet demand (e.g., Vestas, Broadwind, LM Wind Power), or began or completed expansions of existing facilities (e.g., LM Wind Power, Timken).

Figure 10 also highlights the spread of turbine and component manufacturing facilities across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already-established large-scale OEMs. However, even states that are relatively far from major wind markets have manufacturing facilities. For example, most states in the Southeast have wind manufacturing facilities despite the limited number of wind projects in that region. Workforce considerations, transportation costs, and state and local incentives may be some of the factors that drive location decisions.

In 2010, nine out of the eleven wind turbine OEMs with the largest shares of the U.S. market owned at least one domestic manufacturing facility (Acciona, Clipper, DeWind, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas). Since that time, a number of these facilities have closed, reflecting the increased concentration of the U.S. wind industry among the top OEMs, long-term demand uncertainty, mergers among OEMs, and a desire to consolidate production at centralized facilities overseas to gain economies of scale. Even with a consolidated market, however, three major OEMs that serve the U.S. wind industry—GE, Vestas, and SGRE—had one or more operating manufacturing facilities in the country at the end of 2018. In contrast, 14 years ago in 2004, there was only one active OEM (GE) assembling nacelles domestically.¹⁶

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¹⁶ Nacelle assembly is defined here as the process of combining the multitude of components included in a turbine nacelle, such as the gearbox and generator, to produce a complete turbine nacelle unit.
An additional note of interest from 2018 was the continued entry of new composite producers into the U.S. market. Though not tracked within the wind turbine and component manufacturing and assembly facilities dataset otherwise reported here, composites are used in the manufacturing of some wind turbine components. In 2018, Exel Composites acquired Diversified Structural Composites of Erlanger, Kentucky to gain North American manufacturing capacity, and SKAPS Industries acquired Matrix Composites in Henderson, Kentucky. Additionally, SKAPS announced that it would invest $5 million for upgrades and hire 20 workers. Both of these facilities will supply composite materials for U.S. wind energy component manufacturers.

In aggregate, domestic turbine nacelle assembly capability—defined here as the maximum annual nacelle assembly capability of U.S. plants if all were operating at full utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, fell to roughly 10 GW in 2015, and then rose to a record 15 GW in 2018 (Figure 12; AWEA 2019a). In addition, AWEA (2019a) reports that U.S. manufacturing facilities have the capability to produce 11,400 individual blades (~9.2 GW if using average sized turbines) and 3,700 towers (~8.9 GW) annually. Figure 12 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future new installations (see Chapter 9, “Future Outlook”). It demonstrates that domestic manufacturing capability for blades, towers, and nacelle assembly is reasonably well balanced against historical market demand. Modest growth in domestic blade and tower manufacturing capability or additional imports may be necessary to fulfill the total anticipated demand of blades and towers in the coming two years, however, especially when also considering expected demand from partial wind project repowering. Given the anticipated decline in wind power capacity additions as the PTC phases out, domestic manufacturing capability may exceed supply needs starting in 2021.

Notes: Data on blade and tower manufacturing capability are only available from 2012 to 2018. Forecasted annual wind power capacity additions from 2019 through 2022 includes simple average, minimum, and maximum value from analyst projections.


Figure 12. Domestic wind manufacturing capability vs. U.S. wind power capacity installations
Fierce competition throughout the supply chain has caused many manufacturers to execute cost-cutting measures. Nonetheless, the profitability of turbine OEMs has generally declined in the most recent years, following several years of recovery from a low point in 2012 (Figure 13). Moreover, with recent and near-term expected growth in U.S. wind installations, wind-related job totals in the United States reached a new all-time high in 2018, at 114,000 full-time workers, an 8% boost from 2017 (AWEA 2019a). These 114,000 jobs include, among others, those in construction, development and transportation (~45,500), manufacturing and supply chain (~24,000), and operations and maintenance (~21,000).

**Figure 13. Turbine OEM global profitability over time**

*Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports*

The U.S. wind sector is reliant on imports of wind equipment, though the level of dependence varies by component. Some components have a relatively high domestic share, whereas others remain largely imported. These trends are revealed, in part, by data on wind equipment trade from the U.S. Department of Commerce. Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating

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17 Figure 13 only reports data for those OEMs that are “pure-play” wind turbine manufacturers, or that otherwise report profitability just for their wind business. Although it is one of the largest turbine suppliers in the U.S. market, GE is not included because it is a multi-national conglomerate that does not report segmented financial data for its wind turbine division. Figure 13 depicts both EBIT (i.e., “earnings before interest and taxes,” also referred to as “operating profit”) and EBITDA (i.e., “earnings before interest, taxes, depreciation, and amortization”) margins.

18 See the Appendix for further details on data sources and methods used in this section, including the specific trade codes considered.
sets and nacelles (i.e., nacelles with blades, nacelles without blades, and, in some cases, other turbine components internal to the nacelle) as well as imports of other select turbine components shipped separately from the generating sets and nacelles. The turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (as well as generator parts), and blades and hubs.

Import estimates should be viewed with particular caution because the underlying data used to produce Figure 14 are based on trade categories that are not all exclusive to wind. Some of the import estimates shown in Figure 14 therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. The error bars in Figure 14 account for uncertainty in these assumed fractions. In 2012 and 2013, all trade categories shown were either specific to or largely restricted to wind power, and therefore no error bars are shown. After 2013, only nacelles (when shipped alone) are included in a trade category that is not largely exclusive to wind and thus the error bars shown for 2014 through 2018 only reflect the uncertainty in nacelle imports (and, in some cases, other turbine components internal to the nacelle shipped under this trade category). More generally, as noted earlier, Figure 14 does not show comprehensive data on the import of all wind equipment, as not all such equipment is clearly identified in trade categories. The impact of this omission on import and domestic content is discussed later.

As shown, the estimated imports of tracked wind-related equipment into the United States increased substantially from 2006 to 2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then plummeting in 2013 with the simultaneous drop in U.S. wind installations. From 2014 through 2018, imports of wind-related turbine equipment generally followed U.S. wind installation trends, bouncing back from the low of 2013. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind installations

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19 Wind turbine components such as blades, towers, and generators are included in the data on wind-powered generating sets and nacelles if shipped in the same transaction. Otherwise, these component imports are reported separately.

20 The trade code for tower imports is also not entirely exclusive to wind, but is believed to be dominated by wind since 2011. We assume that 100% of imports from this trade category, since 2011, represent wind equipment.
(shown textually on the x-axis of Figure 14), and changes in wind turbine prices. Because imports of wind turbine component parts occur in additional, broad trade categories different from those included in Figure 14, the data presented here understate the aggregate amount of wind equipment imports.

Figure 15 shows the total value of selected, tracked wind-specific imports to the United States in 2018, by country of origin, as well as the main “districts of entry”\(^{21}\): Forty-four percent of the import value in 2018 came from Asia (led by China), 35% from Europe (led by Spain), and 20% from the Americas (led by Mexico). The principal districts of entry were Houston-Galveston, Texas (32%), Port Arthur, Texas (10%), and Great Falls, Montana (8%).

![Figure 15. Summary map of tracked wind-specific imports in 2018: countries of origin and U.S. districts of entry](image)

Looking behind the import data in more detail and focusing on those trade codes that are largely exclusive to wind equipment, Figure 16 shows a number of trends over time in the origin of U.S. imports of wind-powered generating sets, tubular towers, wind blades and hubs, and wind generators and parts.

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\(^{21}\) The trade categories included here are all of the wind-specific import categories for 2018, inclusive of towers, which is believed to be primarily related to wind (see the Appendix for details), and so the 2018 total import volume considered in Figure 15 differs from that in Figure 14. As noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included in this analysis; additionally, in the case of nacelles without blades, the trade code is not exclusive to wind and so related imports are not included in Figure 15 (though they are estimated in Figure 14). As such, the data presented in Figure 15 understate the aggregate amount of wind equipment imports into the United States. Note also that “districts of entry,” as used here, refers to, in some cases, multiple points of entry located in the same geographic region; goods may arrive at districts of entry by land, air, or sea.
For wind-powered generating sets, the primary source markets from 2005 to 2018 have been Europe and, to a lesser extent, Asia, with leading countries often being those that have been home to the major international turbine manufacturers such as Denmark, Spain, Japan, India, and Germany. In 2018, imports of wind-powered generating sets were dominated by Spain and Germany, though the total import value was relatively low (at
The share of imports of tubular towers from Asia was over 80% in 2011 and 2012 (almost 50% was from China), with much of the remainder from Canada and Mexico. From 2013 to 2018, not only did the total import value decline relative to earlier years, but there were almost no imports from China and Vietnam from 2013 to 2015—likely a result of the tariff measures that were imposed on wind tower manufacturers from these countries. Tower imports in 2018 came from a mix of countries from Asia (principally South Korea, Indonesia, and Vietnam), Europe (principally Spain), and North America (principally Canada). With regard to blades and hubs, Asia (principally China) has been the dominant source market since 2016, the European share has been relatively stable, and imports from the Americas have decreased from over 65% in 2013 to under 20% in 2018. Finally, the import origins for wind-related generators and generator parts were distributed across a number of Asian, European, and North American countries; in recent years, the role of Asian imports has decreased, while North American imports (especially from Mexico) have increased.

Because trade data do not track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between imported and domestic content. The trade data also do not allow for a precise estimate of the domestic content of specific turbine components. Nonetheless, based on those data, Table 3 presents rough estimates of the domestic content for a subset of the major wind turbine components used in new (and repowered) U.S. wind projects in 2018. As shown, domestic content is relatively strong for large, transportation-intensive components such as towers and blades. Nacelle assembly also has high domestic content, wherein domestic and imported component are assembled into complete nacelles on U.S. soil.

<table>
<thead>
<tr>
<th></th>
<th>Towers</th>
<th>Blades &amp; Hubs</th>
<th>Nacelle Assembly</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>75%–90%</td>
<td>50%–70%</td>
<td>&gt; 85% of nacelle assembly</td>
</tr>
</tbody>
</table>

These figures, however, understate the wind industry’s reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured in Table 3, including wind equipment (such as mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing). For example, an interview-based approach to estimating domestic content that was conducted in 2012 revealed that domestic content was relatively high for blades, towers, nacelle assembly and nacelle covers at that time, supporting the results depicted in Table 3. However, the domestic content of most of the equipment internal to the nacelle—much of which is not tracked in wind-specific trade data—was considerably lower, often well below 20%.

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22 Since 2014, some nacelles could be imported under a different trade category that is not exclusive to wind equipment, and so are not reported in the figure. As such, trends in imports of wind-powered generating sets before 2014 might be expected to differ from those shown in 2014 and after.
23 In 2016, the Department of Commerce decided to reduce the anti-dumping duties to zero for a single company, which led to an increase in tower imports from Vietnam.
24 On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting domestic fraction would be slightly higher than that presented here.
25 The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.
The project finance environment remained strong in 2018

Initial concerns over the potential negative impact of the Tax Cuts and Jobs Act (which became law in late-December 2017) on wind project finance in the United States have proven to be largely unfounded. In particular, an anticipated reduction in the supply of tax equity due to the lower corporate tax rate (which reduces the tax liability of tax equity investors)\(^26\) failed to materialize, as larger profits generally outweighed the lower tax rate, leaving overall tax capacity largely unchanged (Norton Rose Fulbright 2019). As a result, the market remained active in 2018, continuing to finance the backlog of 100% PTC-qualified equipment.

For example, roughly $6–$7 billion in third-party tax equity was committed in 2018 to finance new wind projects and partial repowerings—this dollar amount is roughly on par with the amount of tax equity raised in each of the previous four years. Partnership flip structures\(^27\) remained the dominant tax equity vehicle, with indicative tax equity yields closing out the year around 7% on an after-tax unlevered basis (Figure 17).

![Figure 17. Cost of 15-year debt and tax equity for utility-scale wind projects over time](https://www.theice.com/iba)

On the debt side, banks continued to focus more on shorter-duration loans (7–10 year mini-perms remained the norm\(^28\)), though a number of banks are reportedly willing to lend for as long as 15 or even 18 years in some

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\(^{26}\) The lower corporate tax rate also reduces the value of depreciation (or expensing) and interest deductions (and under the new law, interest deductions may be further limited if a company's net interest expense exceeds 30% of its adjusted taxable income).

\(^{27}\) A “partnership flip” is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own part of the project. Initially, allocations of tax benefits are skewed heavily in favor the tax equity partner (which is able to efficiently monetize the tax benefits), but eventually “flip” in favor of the project sponsor partner once the tax benefits have been largely exhausted. Cash is also allocated between the partners, with one or more “flip” events, but in recent years has been increasingly directed toward the project sponsor to the extent possible, in order to support back leverage or dividend payments to YieldCo investors.

\(^{28}\) A “mini-perm” is a relatively short-term (e.g., 7–10 years) loan that is sized based on a much longer tenor (e.g., 15–17 years) and therefore requires a balloon payment of the outstanding loan balance upon maturity. In practice, this balloon payment is often paid from the proceeds of refinancing the loan at that time. Thus, a ten-year mini-perm might provide the same amount of leverage as a 17-year fully amortizing loan but with refinancing risk at the end of ten years. In contrast, a 17-year fully amortizing loan would be repaid entirely through periodic principal and interest payments over the full tenor of the loan (i.e., no balloon payment required and no refinancing risk).
cases (Norton Rose Fulbright 2019). As shown in Figure 17, all-in interest rates on benchmark 15-year debt moved higher through much of 2018, but then dropped back down to near 4% toward the end of 2018 as the Federal Reserve paused its multi-year string of 25 basis point rate hikes and shifted to more of a neutral stance, causing both the base rate and swap rates to decline (in concert with bank margins).

With two more years (2019 and 2020) in which to finance and build 100% PTC safe-harbored projects, the market should remain active in the near-term. Post-2020, roughly 10 GW of projects have reportedly qualified for 80% of the PTC’s nominal value, while at least 6.6 GW have reportedly qualified for 60% of the PTC’s nominal value by starting construction by the end of 2018 (Froese 2019). Given the four-year safe harbor window in which to bring PTC-qualified projects online, these 80%- and 60%-PTC projects might be expected to be online by the end of 2021 and 2022, respectively (see Table 4, later, for details on the PTC phase-out).

**Independent power producers own the majority of wind assets built in 2018**

Independent power producers (IPPs) own 6,073 MW or 80% of the 7,588 MW of new wind capacity installed in the United States in 2018 (Figure 18, right pie chart). Investor-owned utilities (IOUs)—namely MidAmerican (817 MW) and Public Service Company of Colorado (600 MW)—installed a total of 1,509 MW (20%). Publicly owned utilities (POUs) own just 2 MW of the new wind power capacity brought online in 2018. Finally, 4 MW of capacity falls into the “other” category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers). Of the cumulative installed wind power capacity at the end of 2018 (Figure 18, left chart), IPPs own 83% and utilities own 15% (13% IOU and 2% POU), with the remaining 2% falling into the “other” category.

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**Figure 18. Cumulative and annual (2018) wind power capacity categorized by owner type**

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29 Many of the “other” projects, along with some IPP- and POU-owned projects, might also be considered “community wind” projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. According to AWEA (2019a), 65 MW (2%) of 2018 wind capacity additions qualified as community wind projects.
Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant.

Electric utilities continued to be the largest off-takers of wind power in 2018 (i.e., ‘users’ of wind to serve load) (Figure 19, right pie chart), either owning wind projects (20%) or buying the electricity from wind projects (27%) that, in total, represent 47% of the new capacity installed last year (with the 47% split between 34% IOU and 12% POU). On a cumulative basis, utilities own (15%) or buy (48%) power from 63% of all wind power capacity installed in the United States (with the 63% split between 43% IOU and 20% POU, with the POU category including community choice aggregators (CCAs)).

Source: Berkeley Lab estimates based on AWEA WindIQ

Figure 19. Cumulative and annual (2018) wind power capacity categorized by power off-take arrangement

Merchant/quasi-merchant projects accounted for 23% of all new 2018 capacity and 23% of cumulative capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracts and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period30) rather than being locked in through a long-term PPA. Most of these projects are located within ERCOT in Texas, though there are some merchant/quasi-merchant projects within other markets, including PJM, MISO, SPP, and NYISO.

Direct retail purchasers of wind power, including a diverse and growing set of corporate and non-corporate off-takers, are supporting 1,794 MW or 24% of the new wind power capacity installed in the United States in 2018 (up from 10% of new capacity installed in 2015, but the same share as in both 2016 and 2017). Direct retail sales should continue to represent a sizable market in coming years, based on AWEA (2019a) estimates that 49% of all wind PPAs that were executed in 2018 were with non-utility purchasers (compared to 40% in 2017, 39% in 2016, 52% in 2015, and 18% for 2014—not all of which have yet achieved commercial operations).

Power marketers were very active throughout the first decade of this century following the initial wave of electricity market restructuring, but their influence has waned in recent years: just 3% of 2018 and 6% of cumulative wind power capacity in the United States sells to power marketers, down from more than 20%.

30 Hedges are often structured as a “fixed-for-floating” power price swap—a purely financial arrangement whereby the wind power project swaps the “floating” revenue stream that it earns from spot power sales for a “fixed” revenue stream based on an agreed-upon strike price. For some projects, the hedge is structured in the natural gas market rather than the power market.
(cumulative) in the early 2000s. Power marketers are defined here to include commercial intermediaries that purchase power under contract and then resell that power to others.\textsuperscript{31}

Finally, just 17 MW of the wind power additions in 2018 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.\textsuperscript{32}

\textsuperscript{31} These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.

4 Technology Trends

Average turbine capacity, rotor diameter, and hub height increased in 2018, continuing the long-term trend

The average nameplate capacity of the newly installed wind turbines in the United States in 2018 was 2.43 MW, up by 239% since 1998–1999 and by 5% over 2017 (Figure 20). The average hub height of turbines installed in 2018 was 88.1 meters, up 57% since 1998–1999 and 2.4% over the previous year. Average rotor diameters have increased at a more rapid pace than hub heights over the long term. The average rotor diameter of wind turbines installed in 2018 was 115.6 meters, up 141% since 1998–1999, and 2.3% over the previous year; this translates to a 479% growth in rotor swept area relative to 1998–1999. Trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.

Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height for land-based wind projects

Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades

As indicated in Figure 20, and as detailed in Figure 21 through Figure 23, increases in nameplate capacity and rotor diameter have outpaced growth in average hub height over the last two decades. That said, there is evidence over the last two years of some increased emphasis on hub height scaling.
Starting with turbine nameplate capacity, Figure 21 presents not only the trend in average nameplate capacity (as also shown earlier, in Figure 20) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines had largely held steady from 2011 through 2015, but has since grown. While it took just six years (2000–2005) for MW-class turbines to almost totally displace sub-MW-class turbines, it took another seven years (2006–2012) for multi-MW-class turbines (i.e., 2 MW and above) to gain nearly equal market share with MW-class turbines. In 2018, 2.0–2.5 MW turbines were the largest share (43% market share), but the shares of 2.5–3 MW and 3+ MW turbines grew significantly (to 33% and 18% in 2018, respectively, versus 9% and 14% in 2017).

Sources: AWEA WindIQ, USWTDB

Figure 21. Trends in turbine nameplate capacity

The average hub height of wind turbines had held roughly constant from 2011 through 2016, but saw increases in 2017 and 2018 (Figure 22). 80-meter towers have dominated the market since 2006. However, 90+ meter towers started to penetrate the market in 2011, and in 2018 had a 47% market share. Although we saw the emergence of towers taller than 100 meters as early as 2007, that segment peaked (at least temporarily) in 2012 when 16% of newly installed turbines were taller than 100 meters. From 2012 through 2017, only 1% or less of newly installed turbines in each year featured towers that tall, but 2018 saw a slight increase to 2%, 90-100 meter towers, though, have seen nearly continuous market share gains since their first appearance in 2011. In 2018, 45% of the market used 90–100 meter towers, up from 37% in 2017. The locations and wind resource conditions of these and other tall-tower installations are shown in more detail in Figure 28 and Figure 29.

The movement toward larger-rotor machines has dominated the industry for some time, with OEMs progressively introducing larger-rotor options for their standard offerings and introducing new turbines that feature larger rotors. As shown in Figure 23, this increase has been especially apparent since 2009, with further growth in 2018. In 2009, no turbines employed rotors that were 100 meters in diameter or larger, while in 2018 99% of newly installed turbines featured such rotors. Rotor diameters of 110 meters or larger started penetrating the market in 2012; in 2018, they had an 87% market share. Turbines with rotor diameters over 120 meters continued their recent growth, reaching 30% market share in 2018.
Figure 22: Trends in turbine hub height

Figure 23: Trends in rotor diameter
Turbines originally designed for lower wind speed sites dominate the market, and are being deployed in a range of wind resource conditions

The growth in the average swept area (in m²) of rotors has been especially rapid over the last two decades, outpacing growth in average nameplate capacity (in W). This has resulted in a decline in the average “specific power” (in W/m²) among the U.S. turbine fleet over time, from 395 W/m² among projects installed in 1998–1999 to 230 W/m² among projects installed in 2018 (Figure 24). The trend toward lower specific power machines slowed in 2018, however, due in part to increased use of IEC Class 2/3 over Class 3 turbines.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites, intended to maximize energy capture in areas where large rotor machines would not be placed under excessive physical stress due to high or turbulent winds. As suggested in Figure 24 and as detailed in the next section, however, such turbines are now in widespread use in the United States—even in sites with relatively high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.

![Figure 24. Trends in turbine specific power](image)

Sources: AWEA WindIQ, USWTDB

Another indication of the increasing prevalence of machines initially designed for lower wind speeds is revealed in Figure 25, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3). Additionally, a significant portion of the turbines installed in recent years have been Class S-2, S-2/3, or S-3, which fall
outside the standard IEC rating for those classes for one reason or another as specified by the turbine design (and are depicted with hash marks in Figure 25).35

The U.S. wind market has recently been dominated by IEC Class 3 turbines, though 2018 witnessed a modest reemergence of Class 2/3 turbines. Since 2013, Class 1, 1/2 and 2 turbines have made up less than 20% of the market and, in 2018, these three classes summed to only 8% of new installations.

Moreover, Class 2, 2/3, and 3 turbine technology has not remained stagnant. Figure 26 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class, matching the average specific power line shown in Figure 24) and also the average specific power ratings of Class 2, 2/3, and 3 (i.e., medium and lower wind speed) turbines installed in the United States. Through 2011, the progressively lower specific power of Class 2 turbines, which dominated the market, drove the overall decline in fleet-wide specific power. Since 2012, the continued drop in fleet-wide specific power has been spurred on by both the penetration of Class 3 and Class 2/3 machines, and by the lower specific powers of all three classes. In 2018, all three classes saw modest but multi-point decreases in specific power from 2017 levels (Class 3: 217 to 213 W/m²; Class 2/3: 247 to 244 W/m²; and Class 2: 273 to 264 W/m²), though fleet-wide the decrease was just one point, 231 to 230 W/m². This difference is explained by the increase in penetration of Class 2/3 turbines in 2018 (see Figure 25), which have a higher average specific power than Class 3 machines.

35 The IEC Class S-2, S-2/3, or S-3 turbines are almost all manufactured by GE Wind. For example, GE rates its 1.7-103 turbine, with a 1.7 MW capacity and a 103-meter rotor diameter, as S-3, indicating that it most closely resembles an IEC Class 3 turbine. Similarly, it rates its 2.0-116 and 2.3-116 models as Class S-3. Others include GE 1.85-87 and GE 2.5-116 (S-2/3), and GE 2.4-107 (S-2). All of the “S” turbines are included in the reported IEC class using their closest class.
Wind turbines continued to be deployed in somewhat lower wind-speed sites

Figure 27 shows the long-term average wind resource for wind turbine installations by year. The figure depicts both the long-term site-average wind speed (in meters per second) at 80 meters for turbines installed that year (right scale) and an index of wind resource quality also at 80 meters (left scale).36

Wind turbines installed in 2018 are located—on average—in sites with an estimated long-term average 80-meter wind speed of 7.8 meters per second (m/s). This represents a slightly higher average wind speed than the previous year, but lower than for those turbines installed from 2014 to 2016. Federal Aviation Administration (FAA) data on not-yet-built “pending” and “proposed” turbines suggest that projects installed in the near future will likely have average wind speeds similar to those of recently installed projects.37 Trends in the wind resource quality index—which represents estimates of the gross capacity factor for each turbine location, indexed to the 1998–1999 installations—are similar. They show a general decline in resource quality for turbines installed through 2011, an increase from 2012 to 2014, and then a decline since then.

Several factors could have driven these observed trends in average site quality. First, the increased availability of low-wind-speed turbines that feature higher hub heights and a lower specific power may have enabled the economic build-out of lower-wind-speed sites over time. Second, transmission constraints (or other siting

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36 The wind resource quality index is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. A single, common wind-turbine power curve is used across all sites and timeframes, and no losses are assumed. We index the values to those projects built in 1998–1999. Further details are found in the Appendix.

37 “Pending” turbines are those that have received a “No Hazard” determination by the FAA and are not set to expire for another 18 months, while “proposed” turbines will also not expire in 18 months but have not yet received any determination. Pending and proposed turbines may not all ultimately be built. However, analysis of past data suggests that FAA pending and proposed turbines offer a reasonable proxy for turbines built in subsequent years.
constraints, or even just regionally differentiated wholesale electricity prices) may have, over time, increasingly focused developer attention on those projects in their pipeline that have access to transmission (or higher-priced markets, or readily available sites without long permitting times) even if located in somewhat lower wind resource sites. The build-out of new transmission (the completion of major transmission additions in West Texas in 2013, for example), however, may at times have offered the chance to install new projects in more energetic sites. Other forms of federal and/or state policy could also play a role. For example, wind projects built in the four-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Many projects availed themselves of this opportunity and, because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers also seized this limited opportunity to build out the less-energetic sites in their development pipelines. Finally, state policies sometimes motivate in-state or in-region wind development in lower wind resource regimes. As RPS policies have become a less-dominant driver of incremental wind additions in recent years (Barbose 2018), however, economic forces have focused new capacity additions in the Interior region of the country.

Sources: AWEA WindIQ, USWTDB, AWS Truepower, Berkeley Lab

**Figure 27. Wind resource quality by year of installation at 80 meters**

Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers are more commonly found in the Great Lakes and Northeast

One might expect that the increasing market share of turbines designed for lower wind speeds would be due to a movement by developers to deploy turbines in lower wind speed sites. There is some evidence of this movement historically (see Figure 27), but it is clear in Figure 28 and Figure 30 that turbines originally designed for lower wind speeds have been deployed in all regions of the United States, in both lower and higher wind speed sites.

Figure 28 presents the percentage of turbines installed in four wind resource quality groups that have one or more of the following three attributes: (a) relatively higher hub height, (b) relatively lower specific power, and (c) relatively higher IEC Class. It focuses solely on turbines installed in the 2016–2018 time period.

Taller towers (i.e., 90 meters and above) saw higher market share during the 2016–2018 period in sites with lower wind speeds. This is likely largely due to the fact that such towers are most economical when deployed
at sites with higher-than-average wind shear (i.e., greater increases in wind speed with height); such sites are prevalent in the Great Lakes and Northeast as shown in Figure 29. That notwithstanding, all regions are seeing increasing tall tower usage.

Lower specific power machines (i.e., under 250 W/m²) installed over this three-year period have been regularly deployed in all resource regimes including at sites with very high wind speeds, though there is some drop-off in the deployment of lower specific power turbines as wind speed increases. Figure 30 shows the prevalence for these low specific power machines in all regions of the country though with higher incidence in the Great Lakes and Interior regions. Turning to IEC Class, we see a somewhat similar story. Specifically, Class 3 and Class 2/3 machines are well-distributed across all wind regimes.

![Diagram]

**Estimated Wind Resource Quality at 80 Meters**

*Note: See the Appendix for details on how wind resource quality at each individual project site is estimated.*

**Sources:** AWEA WindIQ, USWTDB, AWS Truepower, Berkeley Lab

**Figure 28. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality**

The specific locations of tall tower and low specific power installations, as shown in Figure 29 and Figure 30, rarely overlap. In fact, no U.S. wind projects yet feature both very tall towers (>100m) and very low specific power (<200 W/m²), and only 27% of installations with either very tall towers or very low specific power have, respective, “relatively” low specific power (200 to 250 W/m²) or “relatively” tall towers (90 to 100 m). It therefore appears that—thus far—wind developers have tended to trade-off between the two options. It may be that tall towers and low specific power turbines are viewed as, in part, substitutes for increased capacity factors, with diminishing returns in pursuing both simultaneously. Additionally, there may be concerns about the loading on longer blades that occur at the higher wind speeds common with taller towers, or a general desire to stay under the FAA 500 foot “soft cap” highlighted later. Finally, transportation limitations may, in some cases, preclude the longer blades that might otherwise be used in these installations.
Figure 29: U.S. map of cumulative tall tower installations

Figure 30: U.S. map of cumulative low specific power installations
In combination, these findings demonstrate that low specific power and Class 3 and 2/3 turbines, originally designed for lower wind speed sites, have established a strong foothold across the nation and over a wide range of wind speeds. Taller towers, meanwhile, are increasingly being deployed across a wider diversity of sites, though still with a tendency toward lower wind-speed areas in the Great Lakes and Northeast regions. Thus far, wind developers have not tended to deploy lower specific power and tall tower machines simultaneously.

**Wind projects planned for the near future continue the trend of ever-taller turbines**

FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications are reported in Figure 31. The median tip height is shown, along with the 25th and 75th percentiles and the percentage of applications involving turbines over 500 feet (approximately 152 meters) at tip height.

From 2002 through 2016, less than 5% of permit applications included turbines with a total height over 500 feet, growing to 14% for applications in 2017, 39% in 2018, and 44% in 2019 (through late-May 2019). Similarly, although the medians approach 500 feet through 2019, the 75th percentile of 2018 and 2019 applications-to-date are 600 feet tall (183 meters). Note that these data represent total turbine height, not hub height, and therefore include the combined effect of both tower and rotor size. Additionally, turbine heights reported in FAA permit applications can differ from what is ultimately installed.38

![Figure 31. Total turbine heights proposed in FAA applications, over time](image)

The move toward turbines with total heights of over 500 feet is significant. There is anecdotal evidence that developers may have historically perceived a “soft cap” at 500 feet. Although the FAA may require a public comment period for any turbine proposed for higher than 499 feet, perhaps causing some developers to want to stay under that tip height, there are otherwise no height limitations imposed by the FAA.39 The recent growth

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38 Historically, the FAA permit datasets have strongly conformed to subsequent actual installations on average, providing some confidence that the projected trends shown in the FAA permit data will come to pass.

in applications with turbines above 500 feet suggests that developers anticipate continued scaling in hub heights and rotor diameters, breaking through this earlier perceived “soft cap.”

As shown in Figure 32, the height of the greater than 500 feet turbines is not distributed normally, and nor are those turbines distributed evenly across regions. The majority of the proposed tall turbines fall between 590 and 610 feet (~183 meters), but other accumulations exist at 500 feet (~152 meters), 660 feet (~201 meters), and 680 feet (~207 meters). These figures compare to an average total height for turbines installed in 2018 of 479 feet (146 meters). Most of the proposed tall turbines are intended for the Interior region, where the majority of all wind project installations reside. The tallest of these proposed tall turbines, however, would be located in the Great Lakes region, consistent with past tall-tower data reported earlier in Figure 29.

Note: Categories include turbines up to and including the height shown (e.g., 530 are turbines >520 and <=530 feet).

Source: Federal Aviation Administration

The number of wind power projects that employed multiple turbine configurations from a single turbine supplier continued to increase

Among those wind projects built in 2018 that contained at least six turbines, 35% used multiple turbines with different hub heights, rotor diameters and/or capacities—all supplied by the same OEM—continuing a trend started in 2016. As shown in Figure 33, this relatively high degree of intra-OEM turbine specialization within individual projects had not previously been prevalent in the U.S. market before 2016, with 2012 being the next highest year at 13%. Most of these turbines, in the 2016–2018 period, differed by all three of the major characteristics: hub height, rotor diameter, and capacity rating.

While there are multiple possible explanations for this recent trend, the most likely involves how developers commonly qualify projects for the PTC—e.g., by ordering a modest subset of the required number of turbines prior to the applicable construction-start deadline (in order to incur at least 5% of total project costs, per IRS guidance), and then months later ordering the balance of required turbines, which by then might feature different characteristics. Related, some of this trend may simply reflect unused, leftover turbines from earlier procurements being deployed in current projects. A final possibility is that there could be increasing
sophistication with respect to intra-project turbine siting and wake effects optimization, coupled with an increasing willingness among OEMs to provide multiple turbine configurations.

Figure 33. Percent of larger projects employing multiple turbine configurations from a single OEM

Through 2018, twenty-three wind projects have been partially repowered, most of which now feature significantly larger rotors and lower specific power ratings

The trend of partial wind project repowering that largely began in 2017 continued through 2018, and involved replacing major components of turbines to increase energy production with more-advanced turbine technology, extend project life, and access favorable tax incentives. In 2017 and 2018, 23 projects were partially repowered (13 in 2017; 10 in 2018), encompassing 2,425 turbines (1,319 in 2017; 1,106 in 2018) and totaling 3,445 MW (before the partial repowering; 2,133 MW in 2017; 1,312 MW in 2018). Most of the 2017 retrofitted turbines were GE (85%), with the GE share dropping to 47% in 2018. The remainder were SGRE turbines (15% in 2017; 48% in 2018) and, in 2018, Vestas (2%) and Bonus (4%). Retrofitting occurred in Texas and Iowa in 2017, and expanded to five states in 2018: Iowa, North Dakota, New Mexico, Oklahoma, and Texas. Retrofitted projects ranged in age from 8 to 17 years old; the median age was 12 years.

Installing longer blades has been common among these retrofits: 100% of the 2017 turbines and 48% of 2018 turbines involved longer blades, with a mean increase in rotor diameter of 8.1 meters over the two years, as shown in Figure 34. A much smaller number of retrofits included changes to hub height (0% in 2017; 12% in 2018) or nameplate capacity (8% in 2017; 9% in 2018), resulting in an average increase in hub height of just 1.3 meters and in nameplate capacity of just 0.01 MW. With the relatively small change in capacity but the larger change in rotor diameter, these retrofits drove a 16% decrease in average specific power, from 357 W/m² to 301 W/m². Interestingly, in 2018, 423 retrofitted turbines (38%) totaling 320 MW of capacity (24%) saw no change to hub height, rotor diameter, or nameplate capacity. Also unique in 2018, 529 turbines saw a change in manufacturer: 167 Bonus and 362 Vestas turbines were re-labeled SGRE turbines, after the retrofit.
Finally, in 2018, portions of two projects (38 turbines totaling 67.8 MW in Texas) were decommissioned and replaced with new towers, blades, and nacelles—‘full’ repowering as opposed to ‘partial.’ This full repowering is expected to accelerate in the coming years, as turbines installed in the late 1990s and early 2000s age.
5 Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors. The full data sample consists of 965 wind projects built between 1998 and 2017 totaling 86,217 MW (97% of nationwide installed wind capacity at the end of 2017). Excluded from this assessment are older projects installed prior to 1998. In addition, fourteen projects totaling more than 1.4 GW that were either partially or fully repowered in 2018 are excluded from the 2018 capacity factor sample, given that they were at least partly offline during a portion of the year.

The chapter is divided into six subsections: the first presents raw capacity factor data, both by project age and fleet-wide; the second explores variations in capacity factor by region and state; the third focuses on the influence of turbine design and site characteristics; the fourth discusses the impact of wind power curtailment; the fifth examines temporal variations in the wind resource; and the sixth analyzes the possibility of performance degradation over time. A Text Box highlights performance enhancements from projects that were partially repowered in 2017. Unless otherwise noted, all capacity factors in this chapter are reported on an as-observed and unadjusted basis (i.e., after any losses from curtailment, less-than-full availability, wake effects, ice or soil on blades, etc.). In two cases—when looking for performance degradation over time, and when exploring the impact of repowering—we make adjustments for inter-annual variability in the wind resource.

The average capacity factor in 2018 exceeded 40% among wind projects built in recent years, and reached 35% on a fleet-wide basis

Figure 35 shows both individual project and average capacity factors in 2018, broken out by commercial operation date. Projects built in 2018 are excluded, as full-year performance data are not yet available for those projects. From left to right, Figure 35 shows an increase in weighted-average 2018 capacity factors when moving from projects installed in the 1998–2001 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011 show little if any improvement in average capacity factors recorded in 2018. This pattern of stagnation is broken by projects installed in 2012–2013, and even more so by those that achieved commercial operations in 2014–2017. The average 2018 capacity factor among projects built from 2014 to 2017 was 41.9%, compared to an average of 30.8% among all projects built from 2004 to 2011, and 23.8% among all projects built from 1998 to 2001. This apparent improvement in capacity factor among more-recently built projects is impacted by several factors that are explored later, including project location and the quality of the wind resource at each site, turbine scaling and design, and performance degradation over time.

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40 Capacity factor is a measure of the actual energy generated by a project over a given timeframe (typically annually) relative to the maximum possible amount of energy that could have been generated over that same timeframe if the project had been operating at full capacity the entire time.

41 Although some performance data for wind power projects installed in 2018 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2017, often focusing on 2018 capacity factors for those projects.

42 Focusing on capacity factors in a single year, 2018, controls (at least loosely) for time-varying influences such as the degree of wind power curtailment or inter-annual variability in the strength of the wind resource. But it also means that the absolute capacity factors shown in Figure 35 may not be representative over longer terms if 2018 was not a representative year in terms of curtailment or the strength of the wind resource (though as noted later, 2018 was a fairly average wind year overall).

43 The 2018 capacity factor of projects that were built in 2017 may be biased low, due to possible first-year “teething” issues, as projects may take a few months to achieve normal, steady-state production after first achieving commercial operations.
Figure 35 presents data on essentially the same sample of projects built from 1998–2017, but organized in a different way: the blue bars show the average sample-wide capacity factor in each calendar year among a progressively larger cumulative sample each year. Viewed this way, we would expect to see a gradual improvement in capacity factor over time, as the advancements in turbine design (e.g., reductions in specific power, increases in tower height) that have driven the dramatic trend seen above in Figure 35 take longer to infiltrate and influence the overall fleet. In general, the data appear to support this trend, with somewhat higher capacity factors in more recent years—reaching 35% for the first time in 2018. But there is also considerable year-to-year variability in the data, driven in part by two factors—wind energy curtailment and inter-year variability in the strength of the wind resource—that are discussed below.
Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology

The project-level spread in capacity factors shown in Figure 35 is enormous, with capacity factors in 2018 ranging from a minimum of 20% to a maximum of 52% among those projects built in 2017. (This spread is even wider for projects built in earlier years.) Some of the spread in project-level capacity factors—for projects built in 2017 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 37 shows the regional variation in capacity factors in 2018 (using the regional definitions shown in Figure 1, earlier) based on the sample of wind power projects built from 2014 through 2017—a 4-year period that Figure 35 shows to be relatively stable in terms of the nationwide average capacity factors.
Four of the five regions have a rather limited sample, due to the fact that 85% of the total capacity installed from 2014 to 2017 was located in the Interior region. Nonetheless, generation-weighted average capacity factors appear to be highest in the Interior region (43.1%) and the lowest in the Northeast (31.3%), with the Southeast (33.0%), Great Lakes (35.8%), and West (36.6%) falling in between.\footnote{Care should be taken in extrapolating these results, given the relatively small sample size in some regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2018.} Even within these regions, however, there is still considerable spread.

Figure 38 includes data on the full sample of projects built from 1998 through 2017, but breaks things down further by showing average state-level capacity factors in 2018. The overall range runs from 17%–43%, with a notable amount of variation even among states within the same region.
As shown earlier in Chapter 4, the rate of adoption of turbines with taller towers and lower specific power ratings has varied by region. For example, Figure 29 (earlier) shows a greater preponderance of tall towers in the Great Lakes and Northeast regions than elsewhere, while Figure 30 shows lower specific power turbines being most prevalent in the Great Lakes and Interior regions. The relative degree to which projects in each region have employed these turbine design options (which is driven, in part, by the wind resource conditions in each region) influences, to some extent, their capacity factors shown in Figure 37 and Figure 38.

**Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor**

The trends in average capacity factor by commercial operation date seen in Figure 35 can largely be explained by several underlying influences described in Chapter 4 and shown again in Figure 39. First, there has been a trend toward progressively lower specific power and higher hub heights. Second, there was a progressive build-out of lower-quality wind resource sites through 2012, followed by deployment at more energetic sites thereafter. Finally, as shown later, project age itself could be a fourth driver, given the possible degradation in performance among older projects.

The first two of these influences—the decline in average specific power and the increase in average hub height among more recent turbine vintages—have already been well-documented in Chapter 4. They are shown again in Figure 39 in index form, relative to projects built in 1998–1999 (with specific power shown in the inverse, to correlate with capacity factor movements). All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. Meanwhile, at sites with positive wind shear, increasing turbine hub heights can help the rotor to access higher wind speeds. Counterbalancing the decline in specific power and the increase in hub height, however, has been
a tendency to build new wind projects in lower-quality resource areas, especially among projects installed from 2009 through 2012 as shown by the wind resource quality index in Figure 39. This trend reversed course in 2013 and 2014, and has largely held steady since then, though with a dip in 2017 and 2018.

Note: In order to have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

Source: Berkeley Lab

Figure 39. 2018 capacity factors and various drivers by commercial operation date

In Figure 39, the significant improvement in average 2018 capacity factors from among those projects built in 1998–2001 to those built in 2004–2005 is driven by both an increase in hub height and a decline in specific power, despite a shift toward somewhat-lower-quality wind resource sites. The stagnation in average capacity factors that subsequently persists through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. Finally, the sharp increase in average capacity factors among projects built after 2011 is driven by a steep reduction in average specific power coupled with a marked improvement in the quality of wind resource sites. (Average hub height increased modestly over this period.) Looking ahead to 2019, projects with commercial operation dates in 2018 could possibly record higher capacity factors on average than those built in 2017, in light of a slight reduction in average specific power coupled with an uptick in average hub height, while average site quality held steady.

45 As described earlier relating to Figure 27 (with further details found in the Appendix), estimates of wind resource quality are based on site estimates of gross capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. We index the values to those projects built in 1998–1999.
46 The text immediately preceding Figure 27 lists several possible explanations for the buildout of less-energetic sites from 2009 to 2012, including the availability of the Section 1603 grant.
To help disentangle the primary and sometimes competing influences of turbine design evolution and wind resource quality on capacity factor, Figure 40 controls for each. Across the x-axis, projects are grouped into four different categories, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As one would expect, projects sited in higher wind speed areas generally realized higher capacity factors in 2018 than those in lower wind speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range realized significantly higher capacity factors in 2018 than those in a higher specific power range.

As a result, it is clear that turbine design changes (specifically, lower specific power, but also, to a lesser extent, higher hub heights) are driving realized capacity factors higher among projects located within a given wind resource regime. This finding is further illustrated in the side bar on this page, as well as in Figure 41, which again groups projects into the same four different categories of wind resource quality, and then reports average realized 2018 capacity factors by commercial operation date within each category. As before, projects sited in higher wind speed areas have, on average, higher capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been an improvement in capacity factors over time, by commercial operation date. In other words, the fleet-wide improvement in capacity factors by project vintage shown above in Figure 35 is seen across all four wind resource bins, and is not simply a result of shifting toward more-energetic sites over time (in fact, Figure 27 and Figure 39 above show the opposite—i.e., that the wind industry has generally built out less-energetic sites over time).

First wave of partial repowering demonstrates higher capacity factors from lower specific power

Nine projects totaling 2.2 GW partially repowered their turbines in 2017, increasing rotor size in all nine cases and boosting turbine capacity in two of the nine cases (all nine projects re-used the existing towers, resulting in no change to hub height).

For each of these projects, the figure below shows the increase in capacity factor in 2018 (relative to the 4-year average from 2013 to 2016; 2017 is omitted) as a function of the reduction in average specific power (itself a reflection of increased blade length). Not surprisingly, those projects that reduced specific power the most generally saw the largest boost in capacity factor.

Note: All capacity factor data used in this graph are corrected for inter-annual variability in the wind resource (see Appendix for normalization methodology).

Within this chapter, these nine projects are omitted from all graphs in 2017 (the year in which the partial repowering occurred) as well as from most graphs in 2018 (due to difficulties in appropriately characterizing their vintage), with the exception of both Figure 36 and Figure 40, where vintage is not a consideration.

47 The figure only includes those data points representing at least three projects in any single resource-year pair. In years where insufficient sample size prohibits the inclusion of a data point (e.g., in 2013), dashed lines are used to interpolate from the prior year to the subsequent year.
Note: See the Appendix for details on how the wind resource quality at each individual project site is estimated.
Source: Berkeley Lab

**Figure 40.** Calendar year 2018 capacity factors by wind resource quality and specific power: 1998-2017 projects

**Figure 41.** Calendar year 2018 capacity factors by commercial operation date and wind resource quality

Source: Berkeley Lab
**Wind curtailment can differentially impact project performance across sites and regions**

Curtailment of wind project output results from transmission inadequacy and other forms of grid and generator inflexibility. For example, over-generation can occur when wind generation is high but transmission capacity is insufficient to move excess generation to other load centers, or thermal generators cannot feasibly ramp down any further or quickly enough. This can push local wholesale power prices negative, thereby potentially triggering curtailment for economic reasons.

Curtailment might be expected to increase as wind energy penetrations rise, though as shown in Figure 42, this has not always been the case. For example, the Southwest Power Pool (SPP) has the highest wind penetration rate of any of the ISOs shown in Figure 42, yet just 1.3% of potential wind energy generation within the SPP region was curtailed in 2018—down from 2.8% in 2017, and below the curtailment levels in several other ISOs with much lower wind penetration rates.

Moreover, in areas where curtailment has been particularly acute in the past—principally in Texas—steps taken to address the issue have significantly reduced curtailment, even as wind penetration has increased. For example, Figure 42 shows that just 0.5% of potential wind energy generation within the main Texas grid (ERCOT) was curtailed in 2014, down sharply from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. This decline in curtailment corresponds to the significant build-out of new transmission serving West Texas (collectively referred to as the Competitive Renewable Energy Zone upgrades), most of which were completed by the end of 2013. Since 2014, however, wind penetration has continued to increase in ERCOT, and so too has wind curtailment, rising to an average of 2.5% in 2018.48

![Figure 42. Wind curtailment and penetration rates by ISO](image)

**Figure 42. Wind curtailment and penetration rates by ISO**

Though SPP and ERCOT have by far the highest wind penetration rates, other ISOs are also experiencing wind curtailment to varying degrees. The California Independent System Operator (CAISO) and PJM both

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48 This 2.5% ERCOT-wide average masks a long tail on the distribution of individual project-level curtailment, with 11 projects (totaling nearly 1.4 GW) curtailed more than 10% and four of those projects (totaling nearly 600 MW) curtailed 18%–25% in 2018.
experienced only negligible wind curtailment in 2018, but curtailment was more significant within the Midcontinent Independent System Operator (MISO), ISO New England (ISO-NE) and the New York Independent System Operator (NYISO) at 4.2%, 2.8% and 1.7%, respectively. The overall wind power curtailment rate in 2018 across all seven regions shown in Figure 42 was 2.2%. Curtailment rates for all regions include both “forced” (i.e., required by the grid operator for reliability reasons) and “economic” (i.e., voluntary as a result of wholesale market prices) curtailment.

Obviously, wind power curtailment reduces capacity factors. Sample-wide capacity factors in 2018 would have been on the order of 0.7 percentage points higher nationwide absent curtailment in just these seven ISOs.\(^{49}\)

**Temporal variations in wind speed also impact performance**

The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. Figure 43 shows national and regional indices of the historical inter-annual variability in the wind resource among the U.S. fleet over time.\(^{50}\) Though inter-annual variation has, at times, exceeded +/-20% at the regional level, geographical averaging has enabled nationwide variation to remain within +/-10%. More recently, for the third year in a row, wind speeds across the continental United States in 2018 were generally close to their long-term averages, both within each region and on average across all regions (separate data presented by AWS Truepower (2019) tells a similar story).

\(^{49}\) The seven ISOs included in Figure 42 collectively contributed 84% of total U.S. wind generation in 2018. The estimated pre-curtailment sample-wide capacity factor would have been even higher if comprehensive curtailment data were available for all areas of the country.

\(^{50}\) These indices estimate changes in the strength of the average region- or fleet-wide wind resource from year to year and are constructed from ERA5 reanalysis wind speed data for individual project locations by applying applicable wind turbine power curves and then aggregating up to the region or fleet level (see the Appendix for more details). Note that these indices of inter-annual variability differ from the AWS Truepower wind resource quality data presented elsewhere, in that the former show variability from year to year across the entire region or fleet, while the latter focuses on the multi-year long-term average wind resource at specific wind project sites.
Wind project performance degradation may also explain why older projects did not perform as well in 2018

One final variable that could be influencing the apparent improvement in capacity factors in 2018 among more recent projects is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998 to 2001—may have performed worse in 2018 than more recent projects simply due to their relative age. Figure 44 explores this question by graphing both median (with 10th and 90th percentile bars) and capacity-weighted average “weather-normalized” (i.e., to correct for inter-annual variability in the strength of the wind resource) capacity factors over time. Here, time is defined as the number of full calendar years after each individual project’s commercial operation date (COD), and each project’s capacity factor is indexed to 100% in year two in order to focus solely on changes to each project’s capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base, rather than year 1, to reflect the initial production ramp-up period that is commonly experienced by wind projects as they work through and resolve initial “teething” issues during their first year of operations.

Figure 44 suggests some amount of performance degradation, though perhaps only once projects age beyond 9 or 10 years. Potential drivers of any such degradation might include a change in how projects are operated once they age beyond the 10-year PTC window, less-rigorous maintenance protocols following the expiration of warranties and initial service agreements, and/or more frequent component failures and downtime as equipment ages. All of these potential drivers are, in turn, affected by the terms and conditions embedded within power purchase agreements (PPAs)—e.g., whether the PPA includes an availability and/or performance guarantee. Whatever the cause, the decline in capacity factors as projects age could partially explain why, for example, in Figure 36 the sample-wide capacity factors in 2000 and 2001 exceeded 31.5%, while in Figure 35 the projects built in 2000–2001 posted average capacity factors of just 24% in 2018.

![Figure 44. Post-COD changes in capacity factors over time suggest performance degradation](image)

Although these suppositions surrounding Figure 44 are intriguing and worthy of further study, a number of caveats are in order. First, the sample is not the same in each year. The sample shrinks as the number of post-COD years increases, and is increasingly dominated by older projects using older turbine technology that may not be representative of today’s turbines. Second, as with all figures presented in this chapter, turbine decommissioning is accounted for by adjusting the nameplate project capacity as appropriate over time (all the...
way to zero if a project is fully decommissioned), such that each figure, including Figure 44, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity of the overall project. Similarly, repowered projects are considered to be new projects in the year in which the repowered capacity comes online.

Taken together, Figure 35 through Figure 44 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.
6 Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally operations and maintenance (O&M) costs. Sample size varies among these different datasets, and is therefore discussed in each section of this chapter.

**Wind turbine prices remained well below levels seen a decade ago**

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Further cost decreases occurred in 2018, with wind turbines sold at price points similar to the early 2000s.

Figure 45 depicts wind turbine transaction prices from a variety of sources: (1) Vestas, SGRE, and Nordex, on those companies’ global average turbine pricing, as reported in corporate financial reports; (2) BNEF (2018a) and MAKE (2018), on those companies’ turbine price indices by contract signing date; and (3) 122 U.S. wind turbine transactions totaling 30,780 MW announced from 1997 through 2018, as previously collected by Berkeley Lab. Wind turbine transactions can differ in the services included (e.g., whether towers are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices. Most of the prices and transactions reported in the figure are inclusive of towers, and delivery to the site.

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51 Sources of turbine price data for these 122 transactions vary, and include financial and regulatory filings, as well as press releases and news reports. Most of the transactions include turbines, towers, delivery to site, and limited warranty and service agreements, but the precise content of many of the individual transactions is not known.
After hitting a low of roughly $800/kW from 2000 to 2002, average wind turbine prices increased by more than $800/kW through 2008, rising to an average of greater than $1,600/kW. This increase in turbine prices was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth; and increased costs for turbine warranty provisions (Moné et al. 2017).

Since 2008, wind turbine prices have steeply declined, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher (Moné et al. 2017) as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 45, data signal average pricing in the range of $700/kW to $900/kW.

Overall, these figures suggest price declines of roughly 50% since 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and, in some cases, more favorable terms for turbine purchasers (e.g., more-stringent performance guarantees). These turbine price trends have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights are improving capacity factors and further reducing wind power prices. At the same time, it is important to acknowledge that this downward trend is compared to a 2008 peak in the market in terms of turbine pricing, and that looking back farther in time, turbine prices have only recently fallen back to where they were in the early 2000s.

**Lower turbine prices have driven reductions in reported installed project costs**

Berkeley Lab also compiles data on the total installed cost of wind projects in the United States, including data on 44 projects completed in 2018 totaling 5,676 MW, or 75% of the wind power capacity installed in that year. In aggregate, the dataset (through 2018) includes 975 completed wind power projects in the continental United States totaling 82,975 MW and equaling roughly 86% of all wind power capacity installed at the end of 2018. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.

As shown in Figure 46, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs peaked in 2009/2010, with declines since that time. It is not surprising that changes in average installed project costs would lag behind changes in average turbine prices, as this reflects the normal passage of time between when a turbine supply agreement is signed (the announcement date in Figure 45) and when those turbines are actually installed and commissioned (the commercial operations date in Figure 46).

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52 Although our sample size in the 1980s and 1990s is relatively sparse compared to more recent years, for the most part, the individual project-level data and capacity-weighted averages for projects built in the 1980s and 1990s are consistent with average cost data for a subset of those years reported by the California Energy Commission (1988) and Gipe (1995).
In 2018, the capacity-weighted average installed project cost within our sample stood at roughly $1,470/kW. This is down nearly $1,000/kW or 40% from the average reported costs in 2009 and 2010, but is roughly on par with the installed costs experienced in the early 2000s. All of the lowest-cost projects in recent years are located in the Interior region, which dominates the sample and where average costs have fallen by more than $1,000/kW since 2010. Early indications from a limited sample of 14 projects (totaling 2.9 GW) currently under construction and anticipating completion in 2019 suggest that capacity-weighted average installed costs in 2019 will be slightly lower than in 2018, with some developers reporting costs in the $1,100–$1,250/kW range.

**Installed costs differed by project size and turbine size**

Installed costs exhibit economies of scale, which are especially evident when moving from small- to medium-sized projects. Figure 47 shows that among the sample of projects installed in 2018, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 20–50 MW range. Economics of scale continue, though to a lesser degree, as project size increases beyond 50 MW.
Another way to look for economies of scale is by turbine size, on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines. Figure 48 explores this relationship and finds mixed results. On a $/kW basis, projects using larger turbines (in the 2–2.5 MW and 2.5–3 MW bins) do appear to be progressively less-expensive on average than projects using smaller turbines (of between 1.5 and 2 MW). But, the trend ends with projects using turbines of 3 MW or larger—partly due to a number of single-turbine projects using 3 MW turbines installed in 2018 at the same $5,000/kW cost.53

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53 Notwithstanding these small, single-turbine projects using large turbines, in general there is likely to be some correlation between turbine size and project size, at least at the low end of the range of each. As such, Figure 47 and Figure 48 could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size. The same challenges exist when considering regional differences in costs, as the largest projects tend to be built in the lowest-cost Interior of the country—making it difficult to discern the degree to which cost differences are determined by project size or region.
**Installed costs differed by region**

As intimated earlier in Figure 46, regional differences in average project costs are also apparent and may occur due to variations in labor costs, development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2018, Figure 49 breaks out project costs among four of the five regions defined in Figure 1.54 The Interior region—which tends to feature larger projects on flatter terrain—was the lowest-cost region on average, with an average cost of $1,400/kW, while the Northeast—which tends to feature smaller projects on complex terrain—was the highest-cost region in 2018.55 Two of the four regions have very limited sample size, so extrapolations based on these data should be treated with care. Nonetheless, outside of the Interior region, the average cost in 2018 was $1,740/kW.

![Diagram showing installed wind power project costs by region: 2018 projects](source: Berkeley Lab)

Figure 50 shows two histograms that present the distribution of installed project costs among 2018 projects, in terms of both number of projects and capacity. Most of the projects—and most of the low-cost projects—are located in the Interior region, where the distribution is centered on the $1,300–$1,400/kW bins. Projects in other regions generally have higher costs (a number of the high-cost projects shown in the left half of the figure are not visible in the right half because their capacity is very small).

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54 For reference, the 96,433 MW of wind installed in the United States at the end of 2018 is apportioned among the five regions shown in Figure 1 as follows: Interior (68%), West (15%), Great Lakes (11%), Northeast (5%), and Southeast (1%). The remaining installed U.S. wind power capacity is located in Hawaii, Alaska, and Puerto Rico and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

55 Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 49.
Operations and maintenance costs varied by project age and commercial operations date

Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over time (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 168 installed wind power projects in the United States, totaling 14,709 MW and with commercial operation dates of 1982 through 2017. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects and so may not be broadly representative. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the wind project, as well as rent. Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers’ compensation insurance, are generally not included. As such, Figure 51 and Figure 52 are not representative of total operating expenses for wind power projects; the last paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow should be taken only as indicative of potential overall trends. Note finally that the available data are presented in $/kW-year terms, as if O&M represents only a fixed cost. In fact, O&M costs are in part variable and in part fixed; expressing O&M costs in units of $/MWh yields qualitatively similar results to those presented in this section.

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56 The vast majority of the recent data derive from FERC Form 1, which uses the Uniform System of Accounts to define what should be reported under “operating expenses”—namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. Though not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under “electric plant” accounts rather than maintenance accounts.
Figure 51 shows project-level O&M costs by commercial operation date. Here, each project’s O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2018, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2017, only year 2018 data are available, and that is what is shown. Many other projects only have data for a subset of years during the 2000–2018 timeframe, so each data point in the chart may represent a different averaging period within the overall 2000–2018 timeframe. The chart highlights the 83 projects, totaling 11,062 MW, for which 2018 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 51 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2018 O&M costs for the 24 projects in the sample constructed in the 1980s equal $72/kW-year, dropping to $60/kW-year for the 37 projects installed in the 1990s, to $29/kW-year for the 65 projects installed in the 2000s, and staying at $29/kW-year for the 42 projects installed since 2010. This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs...
generally increase as turbines age, component failures become more common, and manufacturer warranties expire, and (2) projects installed more recently, with larger turbines, more sophisticated designs and servicing, and more-mature technology may experience lower overall O&M costs on a $/kW-year basis.

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 52 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale, which reportedly can be significant (BNEF 2018b, Wiser et al. 2019). Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially.

With these limitations in mind, Figure 52 shows an upward trend in project-level O&M costs as projects age, at least among the oldest projects in our sample—i.e., those built from 1998 to 2005—although the sample size after year 4 is relatively limited for these earliest projects. Projects built in 2006 or after, on the other hand, do not show a consistent trend in costs with project age. Figure 52 also shows that projects installed more recently have had, in general, lower O&M costs than those installed in earlier years (1998–2005), at least for the first 12 years of operation, with little difference in observed costs between the sample of projects built from 2006 to 2011 and those built from 2012 to 2017.

As indicated previously, the data presented in Figure 51 and Figure 52 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a company that owned more than 5.2 GW of U.S. wind project assets at the end of 2018 (all of which have been installed since 2000), indicate markedly higher total operating costs. Specifically, EDPR (2019) reported total operating expenses of

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61 Some of the projects installed most recently may still be within their turbine manufacturer warranty period, and/or may have partially capitalized O&M service contracts within their turbine supply agreement. In either case, reported O&M costs would be artificially low.
$59/kW-year for its North American portfolio in 2018—twice the ~$29/kW-year average O&M cost reported above for the 107 projects in the Berkeley Lab data sample installed since 2000. Similarly, a U.S. wind industry survey of total operating costs shows that these expenses for recently installed projects are anticipated to average between $33/kW-year and $59/kW-year, with a mid-point of ~$44/kW-year (Wiser et al. 2019).

The disparity between total operating costs and those costs reported in the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, EDPR breaks out its total U.S. operating costs in 2018 ($59/kW-year) into three categories: supplies and services, which “includes O&M costs” ($34/kW-year); personnel costs ($12/kW-year); and other operating costs, which “mainly includes operating taxes, leases, and rents” ($12/kW-year). Among these three categories, the $34/kW-year for supplies and services is probably closest in scope to the Berkeley Lab data. The recent wind industry survey noted, meanwhile, demonstrates that turbine O&M is expected to constitute less than half of total operating costs (Wiser et al. 2019).

62 Though not entirely clear, EDPR’s reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed. Also, at the end of 2018, EDPR’s North American portfolio consisted of 5,242 MW of wind and 90 MW of PV in the United States, along with 30 MW of wind in Canada and 200 MW of wind in Mexico. Hence, reported North American operating costs are neither entirely U.S.-based nor entirely for wind.
7 Wind Power Price Trends

Earlier sections documented trends in capacity factors, wind turbine prices, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices presented in this chapter. In general, higher-cost and/or lower-capacity-factor projects will require higher PPA prices, while lower-cost and/or higher-capacity-factor projects can have lower PPA prices.

Berkeley Lab collects data on wind PPA prices, resulting in a dataset that currently consists of 448 PPAs totaling 42,018 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2019 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs), and most of them have a utility as the counterparty.63

Except where noted, PPA prices are expressed throughout this chapter on a levelized basis over the full term of each contract, and are reported in real 2018 dollars.64 Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.65 Whenever they are broken out by time, the date on (or year in) which the PPA was signed or executed is used, as that date provides the best indication (i.e., better than commercial operation date) of market conditions at the time. Finally, because the PPA prices in the Berkeley Lab sample are reduced by the receipt of state and federal incentives (e.g., the levelized PPA prices reported here would be at least $15/MWh higher without the PTC, ITC, or Treasury Grant66) and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. That said, we loosely estimate the levelized cost of energy for a large sample of U.S. wind projects in a later text box.

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to solar PPA prices and future natural gas prices, and compared to past wholesale energy and capacity market value. In addition, REC prices are presented in a subsequent text box.

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63 Though we do have pricing details for some PPAs with corporate off-takers, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a “contract for differences” with the corporate off-taker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through traditional sources, like regulatory filings). Though only a minor omission historically, this distinction could limit our sample more severely in the future if corporate off-take agreements remain popular.

64 Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 35 years, with 20 years being by far the most common (at 56% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.

65 Generation weighting is based on the empirical project-level performance data analyzed earlier in this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. In cases where there is not enough operational history to establish a “steady-state” pattern of performance, we used discretion in estimating appropriate weights (to be updated in the future as additional empirical data become available).

66 The estimated levelized PPA price impact of $15+/MWh is different from the PTC’s 2018 face value of $24/MWh for several reasons. First, the PTC is a 10-year credit, whereas most PPAs are for longer terms (e.g., 20 years). Second, the PTC is a tax credit, and must be converted to pre-tax equivalent terms before being compared to PPA prices. Finally, the presence of the PTC constrains financing choices for many wind project owners and drives up the project’s weighted average cost of capital. In other words, if not for the PTC, projects could be financed more cheaply; this difference in the weighted average cost of capital with and without the PTC erodes some of the PTC’s value (for more information, see Bolinger (2014)).
Wind power purchase agreement prices are at historical lows

Figure 53 plots contract-level levelized wind power purchase agreement (PPA) prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region.\textsuperscript{67} This trend is particularly evident in the Interior region, which tends to dominate the overall sample, particularly in recent years. As a result of its low average project costs and high average capacity factors shown earlier in this report, the Interior region also tends to be the lowest-priced region over time.\textsuperscript{68}

![Figure 53. Levelized wind PPA prices by PPA execution date and region (full sample)](image)

Note: Area of “bubble” is proportional to contract nameplate capacity
Source: Berkeley Lab

Figure 54 provides a smoother look at the time trend nationwide and regionally (for just the Interior region and all other regions combined) by averaging the individual levelized PPA prices shown in Figure 53 by year. After topping out above $70/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to below $20/MWh—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline remains substantial, from an average of $57/MWh among contracts executed in 2009 to below $20/MWh in 2017 and 2018. Across all other regions, average PPA prices have been higher.

\textsuperscript{67} Roughly 99% of the contracts that are depicted in Figure 48 are from projects that are already online. For the most part, only the most recent contracts in the sample are from projects that are not yet online.

\textsuperscript{68} Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region’s physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market influences.
The trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent projects, as documented in Chapter 5. Scaling has also enabled reductions in operating costs, as described in Chapter 6. This combination of declining CapEx and OpEx and improved performance—along with historically low interest rates (as shown earlier in Figure 17)—has driven wind PPA prices to today’s record-low levels.

Recent wind power purchase agreements are priced in the mid-teens in some cases

Other sources (e.g., LevelTen Energy 2019) have noted recently signed or offered wind PPAs that are priced significantly below $20/MWh—in some cases in the low-to-mid teens per MWh. Although we have yet to see data on many of these contracts, within our full current sample there are 16 projects (all in the Interior region) totaling 2,468 MW that sell their output through 22 different PPAs signed since early 2015, all with levelized pricing below $20/MWh. Figure 55 focuses only on wind PPA prices signed since 2014, to more-readily show these sub-$20/MWh PPAs. The levelized prices of these 22 PPAs range from $9.3/MWh to $19.7/MWh. Contract terms range from 15–35 years, with an average of 23.5 years.
Despite ultra-low PPA prices, wind faces stiff competition from solar and gas

Figure 56 plots wind PPA prices against utility-scale solar PPA prices on a levelized basis since 2008 (the dashed blue and gold lines show the generation-weighted average wind and solar PPA prices in each year, respectively). Although the gap between wind and solar PPA prices was quite wide a decade ago, that gap has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices.\(^69\)

The figure also shows that wind PPA prices—and, more recently, utility-scale solar PPA prices—have been competitive with the projected fuel costs of gas-fired combined cycle generators over time. Specifically, the black dash markers show the 20-year levelized fuel costs (converted from natural gas to power terms at an assumed heat rate of 7.5 MMBtu/MWh) from then-current EIA projections of natural gas prices delivered to electricity generators.\(^70\) Supported by federal tax incentives, the generation-weighted average levelized wind and solar PPA prices within our contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units.

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\(^{69}\) The solar PPA prices are sourced from Berkeley Lab’s “Utility-Scale Solar” report series (utilityscalesolar.lbl.gov).

\(^{70}\) For example, the black dash marker in 2008 shows the 20-year levelized gas price projection from Annual Energy Outlook 2008, while the black dash in 2019 shows the same from Annual Energy Outlook 2019 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh). The assumed heat rate is intended to reflect an average among the existing fleet of combined cycle generators, rather than the current best-in-class, which might be closer to 6.0-6.5 MMBtu/MWh. Price expectations reflected in NYMEX natural gas futures contracts might differ from the EIA projections used here, but the NYMEX futures strip extends only 12-13 years, compared to the 20-year term used in the figure.
Figure 56. Levelized wind and solar PPA prices and levelized gas price projections

Rather than levelizing the wind PPA prices and gas price projections, Figure 57 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) from PPAs executed in 2016–2018 against the EIA’s latest projections of just the fuel costs of natural gas-fired generation. As shown, the median and generation-weighted average wind PPA prices from contracts executed in the past three years are consistently below the low end of the projected natural gas fuel cost range, while the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall within the overall range by 2025.

Sources: Berkeley Lab, Energy Information Administration

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71 The fuel cost projections come from the EIA’s Annual Energy Outlook 2019 publication, and increase from around $3.27/MMBtu in 2019 to $5.34/MMBtu (both in 2018 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (which start at roughly 8.0 MMBtu/MWh in 2019 and gradually decline to roughly 6.7 MMBtu/MWh by 2050).
Figure 57. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 57 also hints at the long-term value that wind power might provide as a “hedge” against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could ultimately be lower or much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

The economic competitiveness of wind energy is in part dictated by its grid-system value in wholesale power markets

In many regions of the country, wind energy participates in organized wholesale electricity markets for energy and, where available, capacity. In some cases, wind projects directly bid into those markets, and earn the prevailing market price. In other cases—especially when a PPA is in place—the wind energy purchaser will schedule the wind energy into the market, paying the wind project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price.

In either instance, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, the link is direct and affects the revenue of the plant. In the case of wind projects sold under a PPA, on the other hand, the pre-negotiated PPA price establishes plant revenue and, depending of the specifics of the PPA, pricing may or may not be linked to wholesale market prices. In this latter case, however, the revenue earned or that would have been earned by the sale of wind in the wholesale market still reflects the underlying market value of that wind—but in this case, for the purchaser, in the form of an avoided cost. This is because wholesale electricity prices reflect the timing of when energy is cheap or expensive and embed the cost of transmission congestion and losses. A purchaser could, in theory, obtain power from the wholesale market instead of from a wind project. A wind project’s estimated revenue were it participating in the wholesale market therefore reflects costs avoided by the purchaser of wind under a PPA. This (potential) revenue—or value—can be segmented into “energy” market value and, where capacity markets or requirements exist, “capacity” value.
Wholesale energy prices vary over time, and by location. Overall, these prices have fallen over the last decade, in large measure due to the decline in the price of natural gas (Wiser et al. 2017), though gas prices rebounded somewhat in both 2017 and 2018. Moreover, because wind power deployment is sometimes concentrated in areas with limited transmission capacity, wholesale energy prices at the local pricing nodes to which wind plants interconnect are often suppressed. Even absent transmission constraints, wind plants push local wholesale energy prices lower when wind output is high. More generally, the temporal profile of wind output is not always well aligned with system needs, potentially further reducing the energy market value of wind generation. Some of these tendencies apply equally well to wind’s capacity value, which is impacted by the cost of capacity but also by regional rules that define the credit that wind receives for providing capacity. In sum, these trends suggest that the wholesale energy and capacity value of wind may have declined over time, and may in general be somewhat lower than the energy and capacity market value of other generation sources.

Figure 58 estimates the historical wholesale energy and capacity market value of wind across a number of different regions of the country. Specifically, we estimate the energy market value of wind using plant-level hourly wind output profiles and real-time hourly wholesale energy pricing patterns at the nearest pricing node (i.e., locational marginal prices, LMPs). Plant-level capacity values are estimated based on the relevant capacity price or cost for the region in question, and local rules for wind’s capacity credit. Energy and capacity are summed for each plant, and plant-level total value estimates are then averaged to estimate regional values. As a result, the analysis considers the output profile of wind, the location of wind, and how those characteristics interact with local wholesale energy and capacity prices and rules, ultimately yielding an estimate of the revenue that would have been earned had wind sold its output at the hourly LMP and also considering any available capacity-based revenue. The figure then contrasts those wholesale market value estimates for wind with nationwide generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) based on the years in which the PPAs were executed. The comparison between market value estimates and PPA prices is relevant in as much as PPA prices reflect the cost of wind, whereas wholesale energy market value reflects a portion of the value of that wind generation.

These estimates show that the wholesale market value of wind has generally declined over the last decade and varies by region, but that there has been a modest rebound in value over the last two years as gas prices have trended upward. With the sharp drop in wholesale electricity prices and therefore market value of wind in 2009, average wind PPA prices tended to well-exceed the wholesale market value of wind from 2009 to 2012. With continued declines in wind PPA prices, however, those prices reconnected with the market value of wind in 2013 and have remained generally in competitive territory in subsequent years. This suggests that—with the help of the PTC, which reduces PPA prices—wind power developers and off-takers are successfully contracting at levels that are generally comparable in terms of both cost and value, with a number of recent wind PPAs coming in at a discount relative to wholesale market value estimates.

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72 The Appendix provides additional details on the methods used to estimate the wholesale energy and capacity value of wind.
Note: Hourly wind output profiles and wholesale prices are not available for all historical years for all regions; as such, estimates of the wholesale value of wind are not available for all years for all regions.

Sources: Berkeley Lab, ABB, ISOs

**Figure 58. Regional wholesale market value of wind and average levelized long-term wind PPA prices over time**

Because many of the regional wholesale market value estimates are in a similar range, it is difficult to discern individual regional data points in Figure 58. Accordingly, Figure 59 presents these estimates of wind’s wholesale market value, by region, but only for the latest year—2018. The figure also disaggregates the market value estimates into their constituent parts: energy and capacity. The average market value of wind in 2018 was the lowest in SPP ($17/MWh), ERCOT ($18/MWh) and MISO ($22/MWh), whereas the highest-value market was ISO-NE ($41/MWh). Energy value represented the largest share of the total, with capacity value varying widely regionally and being considerably lower in absolute magnitude.
Finally, Figure 60 presents the 2018 market value estimates at a project level. These estimates span a wide range, from a low of $6/MWh to a high of $73/MWh, with a weighted average of $22/MWh. The figure also illustrates the variability that exists in market value within each region, with areas facing transmission congestion and high wind penetrations experiencing lower market value. Higher market value estimates are found in uncongested areas, areas with higher average wholesale prices, and areas where wind output profiles are more-correlated with electricity demand.
**Important Note:** Notwithstanding the above comparisons, neither the wind prices nor wholesale market value estimates (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind (and solar) PPA prices with wholesale value and natural-gas cost estimates in this manner are the following:

- Wind (and solar) PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by virtue of any financial incentives provided to thermal generation and its fuel production. Wholesale electricity prices may also not fully account for the health and environmental costs of various generation technologies, and for other societal concerns such as fuel diversity, fuel security, and resilience.

- Wind (and solar) PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs, and may not fully reflect capital and fixed operating costs.

- Wind and solar PPA prices—once established—are fixed and known. The estimated wholesale market value of wind represents historical values, whereas future natural gas prices are uncertain. Said another way, levelized wind (and solar) PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale value estimates are pertinent to just the specific historical years evaluated, and future natural gas prices reflect uncertain forecasts.

In short, comparing levelized long-term wind PPA prices with either yearly estimates of the wholesale market value of wind or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one’s goal is to account fully for the costs and benefits of wind energy relative to other generation sources. Nonetheless, these comparisons still provide some sense for the short-term competitive environment facing wind energy, and convey how those conditions have shifted over time.
REC prices in RPS compliance markets remained low in 2018

Wind power sales prices presented in this report reflect bundled sales of both electricity and RECs; excluded are projects that sell RECs separately from electricity, thereby generating two sources of revenue. REC markets are fragmented in the United States, but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis.

The figures below present indicative data of spot-market REC prices in both compliance and voluntary markets. Clearly, spot REC prices have varied substantially, both over time and across states, though prices within regional power markets (New England and PJM) are linked to varying degrees.

REC prices in most compliance markets remained relatively low in 2018, reflecting an over-supply relative to current RPS demand. In New England, REC prices continued their slide of the past several years, falling from roughly $15/MWh at the end of 2017 to $5/MWh by year-end 2018. In PJM, REC prices in most states (DE, MD, NJ, PA, OH) rebounded slightly from the prior year, but still remained well below the pricing levels seen in 2014–2015, varying within a range of roughly $5/MWh to $8/MWh over the course of 2018. The two other PJM states shown (DC and IL) have less restrictive eligibility rules than other states in the region, and thus saw even lower REC prices, ranging from $1/MWh to $3/MWh in 2018. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas remained below $1/MWh throughout the year, reflecting sustained over-supply, while prices for voluntary RECs sourced from the Western United States remained at just under $3/MWh over the course of the year.

Notes: Data for compliance markets focus on “Class I” or “Tier I” RPS requirements; these are the requirements for more-preferred resource types or vintages and are therefore the markets in which wind would typically participate. Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded.

Source: Marex Spectron.
In a competitive market, bundled long-term PPA prices can be thought of as reflecting the levelized cost of energy (LCOE) reduced by the levelized value of any incentives received (e.g., the PTC). Hence, as a first-order approximation, LCOE can be estimated simply by adding the levelized value of incentives received to the levelized PPA prices. LCOE can also be estimated more directly from its components, however, and Berkeley Lab has data on both the installed cost and capacity factor of 76.5 GW of wind power projects installed from 1998 through 2017, representing 86% of all capacity built over that period. Here we use those data, in conjunction with time-varying estimates of both operational and financing costs (the latter assuming no PTC), to estimate the LCOE of wind energy over time and by region, in real 2018 dollars. One benefit of this “bottom up” approach to estimating LCOE is that it relies on a large sample of project-level installed cost and performance data, covering more projects than the Berkeley Lab PPA sample.

Based on a variety of data sources (including discussions with industry experts), total operational expenses are assumed to fall from a levelized cost of $82/kW-year in 1998 to $61/kW-year by 2003, $52/kW-year by 2010, and $43/kW-year by 2018 (and are interpolated linearly between these years). The weighted average cost of capital assumes a 65%:35% debt-to-equity ratio (possible in the absence of the PTC), with the cost of debt varying over time based on historical changes in the 20-year swap rate and bank spread, while the cost of equity holds steady at 10%. We assume that project life increases linearly from 20 years for all projects built before 2013 to 25 years for all projects built after 2016. We assume standardized tax rates (a combined federal and state tax rate of 40% for all projects built prior to 2018’s reduction in the corporate federal tax rate, and 27% thereafter), 5-year accelerated depreciation, and 2% annual inflation. For capacity factors, we use an average of available project-level data; as such, projects installed in 1998 may have 20 years of data to average, whereas projects installed in 2017 will have just one year. For 5.7 GW of projects built in 2018 (that have not yet been operating for a full year) for which we have installed cost estimates, we assume that capacity factors match the average capacity factor of projects built in the same region from 2015 to 2017.

The figure depicts the resulting generation-weighted average LCOE values over time, nationwide and by region (regional results are only shown for years in which there is at least 20 MW of project sample). Regional LCOE values span a wide range, but regional and nationwide trends closely follow the PPA price trends shown earlier—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2018. The lowest LCOEs are found in the Interior region, with a 2018 average of $34/MWh and with some projects as low as $27/MWh; looking back in time, these are the lowest wind LCOEs on record. On a nationwide basis, the average LCOE for projects built in 2018 is at an all-time low—$36/MWh.
8 Policy and Market Drivers

The federal production tax credit remains one of the core motivators for wind power deployment

Various policies at both the federal and state levels, as well as federal investments in wind energy research and development (R&D), have contributed to the expansion of the wind power market in the United States. At the federal level, the most impactful policy incentives in recent years have been the PTC (or, if elected, the ITC) and accelerated tax depreciation.

Initially established in 1994 (via the Energy Policy Act of 1992—see Table 4), the PTC provides a 10-year, inflation-adjusted credit that stood at $24/MWh in 2018. The historical impact of the PTC on the wind industry is illustrated by the pronounced lulls in wind additions in the years (2000, 2002, 2004, 2013) during which the PTC lapsed, as well as by the increased activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 2).

In December 2015, via the Consolidated Appropriations Act of 2016 (see Table 4), Congress passed a five-year extension of the PTC (as well as the ITC, which wind projects can elect to receive in lieu of the PTC). To qualify, projects must begin construction before January 1, 2020. Moreover, in 2016 the IRS issued Notice 2016-31, which allows four years for project completion after the start of construction, without the burden of proving continuous construction. This guidance lengthened the “safe harbor” completion period from the previous term of two years.

In extending the PTC, Congress established a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC phases down in 20%-per-year increments for projects starting construction in 2017 (80% PTC value), 2018 (60%), and 2019 (40%). Under the current schedule, projects that commence construction in 2020 and after will no longer receive the PTC.

Developers reportedly qualified a significant amount of new wind turbine capacity for the full PTC by starting construction (as per the IRS safe harbor guidelines) prior to the end of 2016. Chadbourne & Parke (2017) reported two such estimates of PTC-qualified capacity—30–58 GW and 40–70 GW—while consultant MAKE pegged the number at 45 GW (Recharge 2017). Notwithstanding this large volume of turbines that will be deployed through 2020 (within the four-year safe harbor window), an additional 10 GW of wind capacity was reportedly qualified for 80% of the PTC by the end of 2017, with yet another 6.6 GW qualified in 2018 for the 60% PTC (Froese 2019).

A second form of federal tax support for wind is accelerated tax depreciation, which historically has enabled wind project owners to depreciate the vast majority of their investments over a five- to six-year period for tax purposes. Even shorter “bonus depreciation” schedules have been periodically available, since 2008, and the December 2017 tax reform legislation allows both new and used equipment to be fully expensed (i.e., equivalent to 100% bonus depreciation) in the year of purchase; historically, however, the wind industry has not opted to fully utilize such bonus depreciation measures.

The continued near-term availability of federal tax incentives underpins recent low-priced power purchase agreements for wind energy, and is a significant contributor to the ongoing surge in wind capacity additions. As discussed earlier, the tax reform legislation passed in December 2017 seems unlikely to substantially impact wind development during the current PTC cycle. The PTC phase-out, on the other hand, imposes risks to the industry’s competitiveness in the mid- to long-term.
Table 4. History of Production Tax Credit Extensions

<table>
<thead>
<tr>
<th>Legislation</th>
<th>Date Enacted</th>
<th>Start of PTC Window</th>
<th>End of PTC Window</th>
<th>Effective PTC Planning Window (considering lapses and early extensions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ticket to Work and Work Incentives Improvement Act of 1999</td>
<td>12/19/1999</td>
<td>7/1/1999</td>
<td>12/31/2001</td>
<td>24 months</td>
</tr>
<tr>
<td>American Taxpayer Relief Act of 2012</td>
<td>1/2/2013</td>
<td>1/1/2013</td>
<td>Start construction by 12/31/2013</td>
<td>12 months (in which to start construction)</td>
</tr>
<tr>
<td>Tax Increase Prevention Act of 2014</td>
<td>12/19/2014</td>
<td>1/1/2014</td>
<td>Start construction by 12/31/2014</td>
<td>2 weeks (in which to start construction)</td>
</tr>
<tr>
<td>Consolidated Appropriations Act of 2016</td>
<td>12/18/2015</td>
<td>1/1/2015</td>
<td>Start construction by 12/31/2016</td>
<td>12 months to start construction and receive 100% PTC value</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Start construction by 12/31/2017</td>
<td>24 months to start construction and receive 80% PTC value</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Start construction by 12/31/2018</td>
<td>36 months to start construction and receive 60% PTC value</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Start construction by 12/31/2019</td>
<td>48 months to start construction and receive 40% PTC value</td>
</tr>
</tbody>
</table>

Notes: Although the table pertains only to PTC eligibility, the American Recovery and Reinvestment Act of 2009 enabled wind projects to elect a 30% investment tax credit (ITC) in lieu of the PTC starting in 2009. While it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase-out schedule as the PTC, as noted in the table: from 30% to 24% to 18% to 12%). Section 1603 of the same law enabled wind projects to elect a 30% cash grant in lieu of either the 30% ITC or the PTC; this option was only available to wind projects that were placed in service from 2009 to 2012 (and that had started construction prior to the end of 2011), and was widely used during that period. Finally, beginning with the American Taxpayer Relief Act of 2012, which extended the PTC window through 2013, the traditional “placed in service” deadline was changed to a more-lenient “construction start” deadline, which has persisted in the two subsequent extensions. The IRS initially issued safe harbor guidelines providing projects that meet the applicable construction start deadline up to two full years to be placed in service (without having to prove continuous effort) in order to qualify for the PTC. In May 2016, the IRS lengthened this safe harbor window to four full years.

Source: Berkeley Lab
State policies help direct the location and amount of wind power development, but wind power growth is outpacing state targets

As of May 2019, mandatory RPS programs existed in 29 states and Washington, D.C. (Figure 61). In recent years, a sizeable contingent of states have increased their RPS targets, in many cases to levels ranging from 50% to 100% of retail electricity sales. Since the beginning of 2018 and through May 2019, six states (California, Connecticut, Massachusetts, New Jersey, New Mexico, and Nevada) and Washington, D.C. have enacted legislation increasing their RPS targets. In addition to the RPS policies shown in Figure 61, several states—including California, New Mexico, and Washington—have also adopted 100% zero-carbon electricity standards or goals.

Notes: The figure does not include mandatory RPS policies established in U.S. territories or non-binding renewable energy goals adopted in U.S. states and territories. Note also that many states have multiple sub-requirements or “tiers” within their RPS policies, though those details are not summarized in the figure.

Source: Berkeley Lab

Figure 61. State RPS policies as of May 2019

Of all wind power capacity built in the United States from 2000 through 2018, Berkeley Lab estimates that roughly 47% is delivering RECs to load-serving entities with RPS obligations. In recent years, however, the role of state RPS programs in driving incremental wind power growth has diminished, at least on a national basis; 19% of U.S. wind capacity additions in 2018 is estimated to serve RPS targets. Outside of the wind-rich Interior region, however, RPS requirements continue to form a strong driver for wind growth, with 63% of 2018 wind capacity additions in those regions serving RPS demand.

In aggregate, existing state RPS policies will require 570 terawatt-hours of RPS-eligible electricity by 2030, at which point RPS requirements in most states will have reached their maximum percentage targets. Based on the mix and capacity factors of resources currently used or contracted for RPS compliance, this equates to a

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73 The data and analysis reported in this section largely derives from Barbose (2018), with some updates to include 2019 data.
74 Although not shown in Figure 55, mandatory RPS policies also exist in a number of U.S. territories, and non-binding renewable energy goals exist in a number of U.S. states and territories.
total of around 167 GW of RPS-eligible generation capacity needed to meet RPS demand in 2030. Of that total, Berkeley Lab estimates that existing state RPS programs will require roughly 60 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2018. This equates to an average annual build-rate of roughly 5.0 GW per year, only a portion of which will be wind. By comparison, over the past decade, U.S. wind power capacity additions averaged 7.2 GW per year, and total U.S. renewable capacity additions averaged 13.1 GW per year.

In addition to state RPS policies, utility resource planning requirements—primarily in Western and Midwestern states—have motivated wind power additions in recent years. So has voluntary customer demand for “green” power (O’Shaughnessy et al. 2018). State renewable energy funds provide support (both financial and technical) for wind power projects in some jurisdictions, as do a variety of state tax incentives. Finally, some states and regions have enacted carbon reduction policies that may help to support wind power development. For example, the Northeast’s Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy has been operational for a number of years, and California’s greenhouse gas cap-and-trade program commenced operation in 2012, although carbon pricing in these programs has generally been too low to drive significant wind energy growth.

System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain

Wind energy output is variable and often the areas with the greatest wind speeds are distant from electricity load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues impact the pace of wind power deployment. Worldwide experience in operating power systems with wind energy highlights the critical role of system flexibility, defined as the characteristics of a power system that facilitate effective management of variability and uncertainty (IEA 2019).

Figure 62 provides a selective listing of estimated wind integration costs at various levels of wind capacity penetration, from studies completed from 2003 through 2018, and grouped by region of the United States. While studies differ in how they define integration costs, the impacts assessed typically include any additional balancing costs associated with managing increased forecast errors and balancing reserves. These integration costs were not included in the earlier analysis of the market value of wind, which only accounted for the time-varying generation profile and the location of wind in the system. Some of the integration cost studies reported in Figure 62 also include an estimate of the difference in the value of wind with a time-varying profile compared to a more conventional dispatch profile, thereby potentially overlapping with the market value

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75 Berkeley Lab’s projections of new renewable capacity required to meet each state’s RPS requirements assume different combinations of renewable resource types for each RPS state. Those assumptions are based, in large part, on the actual mix of resources currently used or under contract for RPS compliance in each state or region.

76 Berkeley Lab’s estimate of required renewable capacity additions is derived by first estimating incremental renewable generation needed to meet RPS requirements in 2030, relative to available supplies as of year-end 2018. These estimates are performed on a utility-by-utility basis for regulated states, and on a regional basis for restructured states within regional REC markets. These estimates account for the ability of load-serving entities to bank excess RECs for compliance in future years, including any specific banking limitations in individual states. From the incremental renewable generation needs for each state, the corresponding capacity additions are estimated based on the mix and capacity factors of resources currently used or contracted for RPS compliance. This analysis ignores several complexities that could result in either higher or lower incremental capacity needs, including retirements of existing renewable capacity (which would result in higher incremental RPS needs) and the possibility that resources currently serving renewable energy demand outside of RPS requirements (e.g., voluntary corporate procurement) might become available for RPS demand in the future (which would result in lower incremental RPS needs).

77 See, e.g., https://resourceplanning.lbl.gov/login.php

78 See, e.g., https://www.dsireusa.org/

79 See, e.g., https://www.rggi.org/

80 See, e.g., https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm
results presented earlier. The wind integration costs in these studies do not, however, include any costs associated with incremental transmission or the lower capacity contribution of wind, costs that are sometimes included in other integration cost estimates and that are partially captured in the market value estimates presented earlier (e.g., Heptonstall et al. 2017, BP 2018).

Integration costs estimated by the studies reviewed are near or below $5/MWh in all of the regions shown, except the non-California portion of the Western Electricity Coordinating Council (WECC), for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the power is delivered. Studies in the non-California portion of WECC are all focused on individual utilities that also act as balancing authorities, with responsibility to maintain a balance between supply and demand at all times. These studies tend to find higher integration costs, though, with limited exceptions, integration costs estimated by the studies reviewed are still below $10/MWh. Even in the non-California portion of WECC, however, some recent studies find relatively low integration costs. Overall, the results of these studies show that costs tend to increase with wind penetration levels, and tend in general to be lower when balancing areas are larger. Other variations in estimated costs are due, in part, to differences in methods, definitions of integration costs, power system and market characteristics, fuel price assumptions, wind output forecasting details, and the degree to which thermal plant cycling costs are included.

Notes: All studies categorized as WECC (Non-CA) are from individual utilities within WECC. Studies in California and ERCOT are all regional. Many of the studies in the Eastern Interconnect (inclusive of those in MISO and SPP) are regional, but some are from individual utilities. Studies that assessed multiple wind energy penetrations using a common methodology are depicted with connecting lines.

Sources: Additional details on the studies included in this review, and therefore represented in the figure, can be found in the data file associated with this report, downloadable from: https://emp.lbl.gov/wind-technologies-market-report

**Figure 62. Integration costs at various levels of wind power capacity penetration**

Beyond these studies, system operators and planners continue to make progress integrating wind into the power system with new records for instantaneous wind penetration hit each year, including SPP reaching an instantaneous wind penetration of over 70% in April 2019. SPP is developing products to better manage uncertainty in order to minimize manual adjustments by system operators, focusing on uncertainty in the 30-minutes to 3-hour period (SPP 2019). MISO has found that incorporating the ability to dispatch wind resources
in the MISO markets improves congestion management, almost entirely eliminating manual curtailment of wind (Potomac Economics 2018). MISO also found that it needed to better incorporate the technical characteristics of wind turbines into wind energy forecasts, however, as a severe cold snap demonstrated that wind turbines often shut down in especially low temperatures (Potomac Economics 2019a). Finally, system operators continue to examine issues arising from wind generators not naturally contributing inertia to the system and displacing synchronous generators that do (e.g., Matevosyan 2018). An increase in ancillary service requirements in ERCOT in 2018 was primarily due to the need to ensure adequate online inertia (Potomac Economics 2019b).

The best wind resources are often located far from load centers, and so transmission is also particularly important for wind power. Transmission additions were limited in 2018, with approximately 1,300 miles of transmission lines coming online (see Figure 63). The decline since the peak in 2013 is, in part, due to the completion of the Texas CREZ lines in 2013. As of March 2019, FERC (2019b) finds that another 6,300 miles of new transmission (or upgrades) are proposed to come online by April 2021, with 2,200 miles of those lines having a higher probability of completion.

Source: FERC monthly infrastructure reports

Figure 63. Miles of transmission projects completed, by year and voltage

Eight transmission projects that may support wind energy were completed in 2018. In addition, AWEA (2019a) has identified a large number additional near-term transmission projects that, if completed, could support considerable amounts of wind capacity (see Figure 64).
Transmission lines completed in 2018

- 345 kV
- 765 kV

Planned AC
Transmission Lines

- 345 kV
- 362 kV
- 500 kV

Planned HVDC
Transmission Lines

- 320 kV
- 400 kV

Source: AWEA (2019a)

**Figure 64. Transmission line activity: completed in 2018, and planned for near future**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bay Lake (North Appleton to Morgan)</td>
<td>2019</td>
</tr>
<tr>
<td>MVP 5</td>
<td>2018</td>
</tr>
<tr>
<td>Hobico-Chra Draw</td>
<td>2018</td>
</tr>
<tr>
<td>MVP 16</td>
<td>2018</td>
</tr>
<tr>
<td>MVP 12</td>
<td>2018</td>
</tr>
<tr>
<td>Rush Creek</td>
<td>2018</td>
</tr>
<tr>
<td>Windspade II</td>
<td>2018</td>
</tr>
<tr>
<td>China Draw-Phantom-Roadrunner</td>
<td>2021</td>
</tr>
<tr>
<td>Daniels Park - Mules to Parsons</td>
<td>2019</td>
</tr>
<tr>
<td>Daniels Park - Smoky Hill to Daniels Park</td>
<td>2019</td>
</tr>
<tr>
<td>Empire State Connector</td>
<td>2023</td>
</tr>
<tr>
<td>Gateway Central</td>
<td>2022</td>
</tr>
<tr>
<td>Gateway South</td>
<td>2021</td>
</tr>
<tr>
<td>Gateway West</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Grain Belt Express</td>
<td>2023</td>
</tr>
<tr>
<td>Lamar - Frontier Range</td>
<td>2023</td>
</tr>
<tr>
<td>Leopold-Coby</td>
<td>-</td>
</tr>
<tr>
<td>Minnesota Links</td>
<td>2019</td>
</tr>
<tr>
<td>MVP 11</td>
<td>2019</td>
</tr>
<tr>
<td>MVP 4</td>
<td>2019</td>
</tr>
<tr>
<td>MVP 5</td>
<td>2023</td>
</tr>
<tr>
<td>MVP 6</td>
<td>2019</td>
</tr>
<tr>
<td>MVP J</td>
<td>-</td>
</tr>
<tr>
<td>Nebraska Transmission Line</td>
<td>2021</td>
</tr>
<tr>
<td>New England Clean Energy Connect</td>
<td>2022</td>
</tr>
<tr>
<td>New England Clean Power Link</td>
<td>2022</td>
</tr>
<tr>
<td>North Allwood Loop</td>
<td>2019</td>
</tr>
<tr>
<td>Plains &amp; Eastern</td>
<td>2020</td>
</tr>
<tr>
<td>South Plains - Ogalala to Abilene</td>
<td>2021</td>
</tr>
<tr>
<td>South Plains Abilene to Wadsworth</td>
<td>2021</td>
</tr>
<tr>
<td>SunZa Southwest</td>
<td>2020</td>
</tr>
<tr>
<td>TransWest Express</td>
<td>2023</td>
</tr>
<tr>
<td>Two-Vineyards Hobbs</td>
<td>2020</td>
</tr>
<tr>
<td>Western Spirit</td>
<td>2020</td>
</tr>
</tbody>
</table>
9 Future Outlook

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next couple years, before declining, driven by the five-year extension of the PTC and the progressive reduction in the value of the credit over time. Additionally, near-term additions are impacted by improvements in the cost and performance of wind power technologies, which contribute to low power sales prices. Factors impacting wind energy demand also include corporate wind energy purchases and state-level renewable energy policies.

Among the forecasts for the domestic market presented in Figure 65, expected capacity additions increase from 9–12 GW in 2019 to 11–15 GW in 2020 (BNEF 2019, Wood Mackenzie 2019, Navigant 2019, IHS 2019, GWEC 2019). Forecasts for 2021 to 2028, on the other hand, show a downturn in additions in part due to the PTC phase-out. Expectations for continued low natural gas prices and modest growth in electricity demand also put a damper on growth expectations, as do limited transmission infrastructure and competition from other resources (natural gas and—increasingly—solar, in particular) in certain regions of the country. At the same time, declines in the price of wind energy over the last decade have been substantial, helping to improve the economic position of wind even in the face of challenging competition. The potential for continued advancements and cost reductions enhances the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state policies supportive of wind energy. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse and contrasting underlying potential trends, wind power additions, especially after 2021, remain uncertain.


In 2015, the DOE published its Wind Vision report (DOE 2015), which analyzed a scenario in which wind energy reaches 10%, 20%, and 35% of U.S. electric demand in 2020, 2030, and 2050, respectively. Actual and projected wind additions from 2014 through 2020 (60 GW, in total) are greater than the pathway envisioned in the DOE report (54 GW). Projected growth from 2021 through 2028 (45 GW), however, is well below the Wind Vision pathway (90 GW). As discussed in the DOE Wind Vision (2015), and as further suggested by these comparisons, achieving 20% wind energy by 2030 and 35% by 2050 would likely require efforts that go...
beyond business-as-usual expectations. Mai et al. (2017) specifically explore the role of wind technology advancement, finding that aggressive continued cost reductions will be necessary to achieve the Wind Vision deployment pathway absent substantial changes in policy or market conditions.
References


Navigant. 2019. Personal communication with Bruce Hamilton. May.


Appendix: Sources of Data Presented in this Report

Installation Trends
Data on wind power additions and repowering in the United States (as well as certain details on the underlying wind power projects) are sourced largely from AWEA (2019a). Annual wind power capital investment estimates derive from multiplying wind power capacity data by weighted-average capital cost data (provided elsewhere in the report). Data on non-wind electric capacity additions come from ABB’s Velocity database, except that solar data come from Wood Mackenzie Power & Renewables.

Global cumulative (and 2018 annual) wind power capacity data are sourced from GWEC (2019) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Wind energy penetration is compiled by AWEA (2019a).

The wind project installation map was created by NREL, based (in part) on AWEA’s WindIQ project database. Wind energy as a percentage contribution to statewide electricity generation and consumption is based on EIA data for wind generation divided by in-state total electricity generation or consumption in 2018.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO or utility. Only projects that were active in the queue, but not yet built or with a signed interconnection agreement, at the end of the years specified are included. Suspended projects are not included.

Industry Trends
Turbine manufacturer market share data are derived from the AWEA WindIQ project database, with some processing by Berkeley Lab.

Information on wind turbine and component manufacturing comes from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on recent U.S. nacelle assembly capability come from AWEA (2019a), as do data on U.S. tower and blade manufacturing capability. The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports (where necessary, focusing only on the wind energy portion of each company’s business).

Data on U.S. imports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. Census Bureau, and obtained from the U.S. Census’s USA Trade Online data tool (https://usatrade.census.gov/). The analysis of the trade data relies on the “customs value” of imports as opposed to the “landed value” and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report.
Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis

<table>
<thead>
<tr>
<th>HTS Code</th>
<th>Description</th>
<th>Years applicable</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>8502.31.0000</td>
<td>wind-powered generating sets</td>
<td>2005–2018</td>
<td>includes both utility-scale and small wind turbines</td>
</tr>
<tr>
<td>7308.20.0000</td>
<td>towers and lattice masts</td>
<td>2006–2010</td>
<td>not exclusive to wind turbine components</td>
</tr>
<tr>
<td>7308.20.0020</td>
<td>towers - tubular</td>
<td>2011–2018</td>
<td>mostly for wind turbines</td>
</tr>
<tr>
<td>8501.64.0020</td>
<td>AC generators (alternators) from 750 to 10,000 kVA</td>
<td>2006–2011</td>
<td>not exclusive to wind turbine components</td>
</tr>
<tr>
<td>8501.64.0021</td>
<td>AC generators (alternators) from 750 to 10,000 kVA for wind-powered generating sets</td>
<td>2012–2018</td>
<td>exclusive to wind turbine components</td>
</tr>
<tr>
<td>8412.90.9080</td>
<td>other parts of engines and motors</td>
<td>2006–2011</td>
<td>not exclusive to wind turbine components</td>
</tr>
<tr>
<td>8412.90.9081</td>
<td>wind turbine blades and hubs</td>
<td>2012–2018</td>
<td>exclusive to wind turbine components</td>
</tr>
<tr>
<td>8503.00.9545</td>
<td>parts of generators (other than commutators, staters, and rotors)</td>
<td>2006–2011</td>
<td>not exclusive to wind turbine components</td>
</tr>
<tr>
<td>8503.00.9546</td>
<td>parts of generators for wind-powered generating sets</td>
<td>2012–2018</td>
<td>exclusive to wind turbine components</td>
</tr>
<tr>
<td>8503.00.9560</td>
<td>machinery parts suitable for various machinery (including wind-powered generating sets)</td>
<td>2014–2018</td>
<td>not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category [81]</td>
</tr>
</tbody>
</table>

Some trade codes are exclusive to wind, whereas others are not. Assumptions are made for the proportion of wind-related equipment in each of the non-wind-specific HTS trade categories. These assumptions are based on: an analysis of trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with USITC and wind industry experts; USITC trade cases; and import patterns in the larger HTS trade categories. The assumptions reflect the rapidly increasing imports of wind equipment from 2006 to 2008, the subsequent decline in imports from 2008 to 2010, and the slight increase from 2010 to 2012. To account for uncertainty in these proportions, a ±10% variation is applied to the larger trade categories that include wind turbine components for all HTS codes considered, except for nacelles and other wind equipment shipped under 8503.00.9560—a range of ±50% of the total estimated wind import value is applied for HTS code 8503.00.9560.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from the Intercontinental Exchange, BNEF, and Norton Rose Fulbright. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of AWEA’s WindIQ project database.

Wind Turbine Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, specific power, and IEC Class was compiled by Berkeley Lab within the United States Wind Turbine Database (USWTDB) based on information provided by AWEA, turbine manufacturers, standard turbine specifications, the FAA, web searches, and other sources. The data include projects with turbines greater than or equal to 100 kW that began operation in 1998 through 2018. Some turbines have not been rated within a formal numerical IEC Class, but are instead designated as Class “S-2,” “S-2/3,” or “S-3” for special. These turbines were recoded to their respective

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\[81\] This was effective in 2014 as a result of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blades—which are essential to wind-powered generating sets as defined in the HTS.
numerical class for purposes of analysis but are also reported separately where appropriate. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA “Obstacle Evaluation / Airport Airspace Analysis (OE/AAA)” data containing prospective turbine locations and total proposed heights were used to estimate future technology trends. Any data with expiration dates between March 31, 2019 and September 30, 2020 were categorized as either “pending” turbines (for those that already had received an evaluation of “no hazard”) or “proposed” turbines (for those that were still being evaluated). For Figure 32, no distinction regarding either expiration dates or hazard evaluations was made—instead, all permit applications in the OE/AAA file were used and were binned based on their submission year.

**Performance, Cost, and Pricing Trends**

Wind project performance data were compiled overwhelmingly from two main sources: FERC’s Electronic Quarterly Reports and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT, MISO, PJM, NYISO, SPP, ISO-New England, and CAISO.

The following procedure was used to estimate the quality of the wind resource in which wind projects are (or are planned to be) located. First, within the USWTDB, the location of individual wind turbines and the year in which those turbines were (or are planned to be) installed were identified using FAA Digital Obstacle (i.e., obstruction) files and FAA OE/AAA files, combined with Berkeley Lab and AWEA WindIQ data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from the average mapped 80-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites) and assuming no losses. To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100% assigned in that period. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the “lower” category includes all projects or turbines with an estimated gross capacity factor of less than 40%; the “medium” category corresponds to ≥40%–45%; the “higher” category corresponds to ≥45%–50%; and the “highest” category corresponds to ≥50%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 52,115 turbines of the 52,830 installed from 1998 through 2018 in the continental United States (i.e., nearly 99%). Roughly 80% of the 715 turbines that are not mapped are more than twelve years old.

The relative strength of the average “fleet-wide” wind resource from year to year is estimated based on weighting each operational project-level wind resource (or “wind index”) by its share of the total operational fleet-wide capacity for the particular year. For each individual wind plant, an annual wind index is calculated as the ratio of a particular year’s predicted capacity factor to the long-term average predicted capacity factor (with the long-term average calculated from 1998-2018). Site-level available wind resources are calculated for each hour of each year based on ERA5 reanalysis wind speed data for each plant’s location. ERA5 has a horizontal resolution of ~30 km × 30 km. Site-specific estimated wind speeds (with the geographic resolution previously noted) are interpolated between ERA5 model heights to the corresponding representative hub-height for each wind project. Hourly wind speeds at each project are then converted to wind power by applying project-specific power curves. Power curves are based on the set of turbine-specific power curves reported by thewindpower.net, which provides power curves for more than 750 separate turbines. Although many projects contain only a single type of turbine, some projects contain multiple turbine types. For the latter projects, a turbine power curve is selected that most closely matches the average turbine capacity, rotor diameter, and specific power across the project. The wind indices are calculated without accounting for wake, electrical, or
other losses, or curtailment, and are based only on the ERA5 wind speeds. These indices are used to represent changes in the wind resource from one year to the next, and reflect the ERA5-based strength of the total potential wind resource given the types of turbines that are deployed at each site. Note that these data and indices are used to characterize year-to-year variations in the strength of the wind resource, whereas AWS Truepower estimates are used to characterize the strength of the site-specific long-term annual average wind resource. We use AWS Truepower estimates for the latter need due to their higher geographic resolution.

Historical U.S. wind turbine transaction prices were, in part, compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. Additional data come from Vestas, SGRE and Nordex corporate reports, BNEF, and MAKE Consulting.

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, EIA Form 860, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, Windpower Monthly magazine, AWEA’s Wind Energy Weekly, the DOE and Electric Power Research Institute Turbine Verification Program, Project Finance magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively; for projects installed from 2013 through 2016, EIA Form 860 data are used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not all equally credible, less emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer greater insight. Only cost data from the contiguous lower-48 states are included.

Wind project O&M costs come primarily from two sources: EIA Form 412 data from 2001 to 2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. A small number of data points are suppressed in the figures to protect data confidentiality.

Wind PPA price data are based on multiple sources, including prices reported in FERC’s Electronic Quarterly Reports, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs.

To calculate the historical wholesale energy market value of wind we match estimated hourly wind generation profiles to hourly nodal real-time wholesale prices. As described in more detail below, we also calculate the capacity value at each plant, based on the modeled wind profiles and ISO-specific rules for wind’s capacity credit and ISO-zone-specific capacity prices. We calculate the average $/MWh energy and capacity value for each plant and year. We estimate the ISO-level average value by weighting plant-level value estimates by plant capacity. To calculate the average energy and capacity $/MWh value, we calculate the numerator based on actual hourly generation after curtailment but calculate the denominator based on the total generation without curtailment. We account for curtailment only in the numerator so that increased levels of curtailment will reduce the average $/MWh value. The MWh, in this case, reflect potential wind generation before curtailment. Note that public data do not broadly exist for hourly wind output profiles at the plant level. Consequently, we leverage the ERA5-based modeled wind generation estimates described earlier. However, when developing energy value estimates we adjust plant-level ERA5-based generation estimates for curtailment and apply a bias correction process. The resulting generation estimates incorporate publicly available information on actual generation as well as site-specific ERA5 modeled wind speeds. One exception to this process is for plants located in ERCOT. ERCOT provided high time resolution records of plant level generation and curtailment going back to 2013, and, where available, we use these reported values over the modeled values.

Details on the processes related to curtailment and bias correction follow: Total curtailment is reported by each ISO for either each hour or each month. CAISO, ERCOT, and SPP report hourly curtailment; MISO, NYISO, ISO-NE, and PJM report monthly curtailment. We distributed total reported hourly curtailment evenly across
all plants within a particular ISO that face local prices below zero for that hour (i.e., generation from plants with negative prices is reduced by an equal percentage so that the total proportion of generation curtailed across all plants in the ISO matches the proportion of generation curtailed as reported by the ISO). If, in a particular hour, there is not enough modeled curtailment among plants with prices below zero, the price cutoff point is incrementally raised until the curtailment proportion matches the reported total. A similar process is used to distribute monthly curtailment ISO totals to individual plants and hours. The bias correction involves an iterative linear scaling approach so that each plant’s total modeled generation matches its reported generation (from EIA or FERC, typically at the monthly or quarterly level) and the sum of estimated hourly generation across all plants within each ISO matches the hourly total wind generation reported by each ISO. Because we do not necessarily include the same exact set of plants that each ISO includes when reporting its total hourly wind production, we scale the ISO-level total generation to match the total estimated generation within our set of plants, and effectively match the relative hourly shape at the ISO-level. For our value estimates we exclude plants that fall outside the ISO regions because we cannot include curtailment or bias correction for those plants. Also, depending on the ISO, curtailment data may not be available for all historical years. When curtailment data are not available, we continue to employee the bias correction process but do not pre-process the generation estimates for curtailment.

Our data source for hourly nodal real-time wholesale electricity prices and for hourly regional wind output profiles is ABB’s Velocity Suite database (which, in many cases, derives data from ISOs). Curtailment data are downloaded directly from each ISO, or in some cases, from ABB’s Velocity Suite database. For each wind power plant, we identify the nearest or most-representative pricing node (in most cases within 10 km of the plant), which allows us to match representative prices to each plant. For some regions, hourly wind output profiles are only available for a subset of the relevant years of our analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions. Finally, as indicated earlier, capacity value is estimated for each plant based on modeled wind profiles and ISO and ISO-zone specific capacity prices or costs, as well as relevant regional rules for wind’s capacity credit. No capacity value is calculated for ERCOT because ERCOT runs an energy-only market that does not require load serving entities to meet a resource adequacy obligation. As for capacity prices and costs, many regions have organized capacity markets, in which case we use market-clearing prices from those auctions in concert with ISO-rules or estimates for the capacity credit of wind plants. For regions where load serving entities have a resource adequacy obligation but lack organized capacity markets, on the other hand, we use available data from regulatory bodies to approximate capacity costs and combine those data with regional estimates or rules for wind’s capacity credit.

To compare the price of wind to the cost of future natural gas-fired generation, the range of fuel cost projections from the EIA’s *Annual Energy Outlook 2019* is converted from $/MMBtu into $/MWh using heat rates derived from the modeling output. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.
2018 Wind Technologies Market Report

For more information visit, energy.gov/eere/wind

DOE/G0-102019-5191 • August 2019

Front cover photo from Dennis Schroeder, NREL
Back cover photo from Deborah Donovan, Sustainable Energy Advantage, LLC
Original Filing
Public Utilities Commission of Nevada
Electronic Filing
Submitted: 6/24/2019 3:01:24 PM
Reference: 7b7ffeaa-9e1a-4cc9-a25f-7045fc0a09c0
Reference:
Filed For: NPC and SPPC
In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s LynnDInocenti

By electronically filing the document(s),
the filer attests to the authenticity of the electronic signature(s) contained therein.

This filing has been electronically filed and deemed to be signed by an authorized agent or
representative of the signer(s) and
NPC and SPPC
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of the Third Amendment to the 2018 Joint Integrated Resource Plan, including a request for approval of three new renewable energy power purchase agreements, and updates to the Transmission Action Plan including several new projects needed to allow the new renewable facilities to interconnect into the system, and to meet distribution load growth.

Docket No. 19-06___

VOLUME 3 OF 5

TECHNICAL APPENDIX

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<tr>
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<td>REN-2</td>
<td>2019 IRP Generic Placeholder</td>
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<td>REN-3</td>
<td>2019 Generic Placeholder Pricing (Confidential)</td>
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<td>2019 IRP Buildout Scenarios</td>
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<td>Fall 2018 RE-RFP Protocol</td>
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<td>Long-Term RPP Agreement with Solar Partners XI, LLC</td>
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**Supply Amount Table Source:** 2018 Fall RE RFP Amendment C (0320-19)
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* Pricing, June - August, during the period 1700-2100 is 6.5x higher
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<th>Off-Peak (kWh)</th>
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<td>(119,337)</td>
<td>$ 22.32</td>
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* Pricing, June - August, during the period 1700-2100 is 6.5x higher


<table>
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<tr>
<th>Year</th>
<th>Total kPCs</th>
<th>Net MW hrs</th>
<th>Degradation (per Bid *)</th>
<th>Price /MWh*</th>
<th>Yield</th>
<th>Degrad.</th>
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<tr>
<td>2021</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$ -</td>
<td>0.00%</td>
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</tr>
<tr>
<td>2022</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>$ -</td>
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<td>0.00%</td>
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<tr>
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<td>0.00%</td>
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<td>0.45%</td>
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<td>1.45%</td>
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<td>1.95%</td>
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<td>97.55%</td>
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<td>(65,684)</td>
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<td>95.05%</td>
<td>4.95%</td>
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<td>2035</td>
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<td>(121,349)</td>
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<td>5.45%</td>
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<td>2036</td>
<td>2,094,099.9</td>
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<td>(132,482)</td>
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<td>5.95%</td>
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<td>(143,615)</td>
<td>$ 24.79</td>
<td>93.55%</td>
<td>6.45%</td>
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<td>2038</td>
<td>2,071,834.1</td>
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<td>(154,747)</td>
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<td>7.95%</td>
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<td>8.45%</td>
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<td>8.95%</td>
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<td>(266,076)</td>
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<td>88.05%</td>
<td>11.95%</td>
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* Pricing, June - August, during the period 1700-2100 is 6.5x higher
REN-2

Nevada Power & Sierra Generic Placeholder Profiles Common to all Plans

Summary

Generic Placeholders

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<tr>
<th>Placeholder</th>
<th>Nameplate Type</th>
<th>MW AC</th>
<th>Location</th>
<th>Capacity</th>
<th>Yr 1 Output</th>
<th>Annual Degradation</th>
<th>Associated Station Usage</th>
<th>Credits?</th>
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<tr>
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<td>PV</td>
<td>25</td>
<td>Southern NV</td>
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<td>75,980</td>
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<td>164,312</td>
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<td>30,000</td>
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</table>

PV Projects:
Tracking assume single axis. Output, capacity & degradation assume Tier 1 crystalline or thin panel technology. Actual generation, capacity and degradation are project specific and would be based on the prevailing technology at the time the project is placed into service. Degradation is not applied to generic placeholder PPA projects. The assumption is that the counter party will assume the production risk.

Geothermal:
Dry cooled with sufficient resource to support a 75% capacity factor and a 18% parasitic load for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine. Actual generation, station usage and capacity factor are project and resource specific and would be based on the prevailing technology at the time the project is placed into service.

Capacity factor are calculated based on nameplate
# PPA PV SN 25 MW Tracking (X), Southern Nevada (1X, 2X, 3X, & 4X)

This profile is specific to Nevada Power

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<tr>
<th>Project Name</th>
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<td>Energy Source</td>
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<td>Life</td>
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<td>Owner</td>
<td>PPA</td>
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<td>NPC</td>
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<td>Capacity Factor (Yr 1)</td>
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Supply Amount Table Source: 2014 NPC RFP Southern NV Site, Tier 1 Panels

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<th>Hour Ending</th>
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<th>Peak (MW-h)</th>
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* for calculation purposes, the worksheet assumes that all projects declare COO on the 1st of the month, the above does not take into account test energy/credits

PPA PV SN 25 MW Tracking (X) 75,980.3
PPA PV SN 25 MW Tracking (X) 151,960.6
PPA PV SN 25 MW Tracking (X) 227,960.8
PPA PV SN 25 MW Tracking (X) 303,921.1

Page 11 of 314
PPA PV NN 25 MW (X), Northern Nevada (1X, 2X, 3X & 4X)

This profile is specific to Sierra

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Supply Amount Table Source: 2014 NPC RFP North NV Site, Tier 1 Panels

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In-Service Month: * Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

Net PV 69,252.4 66,552.1 62,970.3 57,585.4 51,058.8 43,138.2 34,637.8 25,767.1 17,589.1 10,820.7 5,654.7 2,557.0

90.10% 90.90% 83.17% 73.73% 62.29% 50.02% 37.21% 25.40% 15.63% 8.17% 3.69%

* for calculation purposes, the worksheet assumes that all projects declare CO2 on the 1st of the month, the above does not take into account test energy/credits

PPA PV NN 25 MW Tracking (X) 69,252.4
PPA PV NN 25 MW Tracking (X) 138,504.8
PPA PV NN 25 MW Tracking (X) 207,757.3
PPA PV NN 25 MW Tracking (X) 277,009.7
PPA Geo NV 25 MW (X), Northern Nevada (1X, 2X, 3X & 4X)
This profile is common to both Nevada Power & Sierra

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Supply Amount Table Source: Dry Cooled, Enhanced Capacity Factor

Geothermal SU: Energy consumption associated with geothermal brine (extract, transport, pump, etc.) > 18% 30,000.0

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<th>May</th>
<th>Jun</th>
<th>Jul</th>
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* for calculation purposes, the worksheet assumes that all projects declare COD on the 1st of the month, the above does not take into account test energy/credits

PPA Geo NN 25 MW (1X) 164,312.2 30,000.0
PPA Geo NN 25 MW (2X) 328,624.5 60,000.0
PPA Geo NN 25 MW (3X) 492,936.7 90,000.0
PPA Geo NN 25 MW (4X) 657,248.9 120,000.0

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RENI-3
FILED UNDER CONFIDENTIAL SEAL
Renewable – Compliance Build Out Scenarios

Base Retail Sales, All Placeholder Buildout

NPC RPS Compliance Outlook

50 % RPS / All Placeholders
Base Retail Sales, Full Loan Payback

Projected RPS credit short-fall assuming no new projects >> 2028
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<th>COD MTH/yr</th>
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Total NPC: 3,250.0

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
### Nevada Power - Projected Portfolio Energy Credits by Year and Type

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<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked or (Deficit Carry Forward adjusted for Credits Repaid to SPCC)</th>
<th>Total KPCs</th>
<th>RPS Credit Requirement</th>
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Renewable – Compliance Build Out Scenarios

Base Retail Sales, All Placeholder Buildout

SPPC RPS Compliance Outlook

50% RPS / All Placeholders
Base Retail Sales, Full Loan Payback

Projected RPS credit short-fall assuming no new projects >> 2024
## Base Retail Sales, All Placeholder Buildout SPPC

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<tr>
<th>Project</th>
<th>MW</th>
<th>COD MTH/YR</th>
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**Total SPPC**  
Total: 1,675.0

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
### Sierra Pacific Power - Projected Portfolio Energy Credits by Year and Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked + Pool Repayments or (Deficit Carry Forward)</th>
<th>Total KPCs</th>
<th>RPS Credit Requirement</th>
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<tbody>
<tr>
<td>2019</td>
<td>1,434,742</td>
<td>(598,695)</td>
<td>135,223</td>
<td>346,266</td>
<td>0</td>
<td>629,778</td>
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NPC RPS Compliance Outlook
Gemini, Moapa & Southern Bighorn
50% RPS, Base Retail Sales

Projected RPS credit short-fall assuming no Placeholder Projects >> 2028
### Base Retail Sales, Gemini, Moapa & Southern Bighorn NPC

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<th>MW</th>
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<td>12 2022 30%</td>
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<tr>
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<td>9 2023 60%</td>
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<td>12 2023 100%</td>
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**Total NPC** 4,205.0 4,205.0

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Nevada Power - Projected Portfolio Energy Credits by Year and Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked or (Deficit Carry Forward) adjusted for Credits Repaid to SPCC</th>
<th>Total KPCs</th>
<th>RPS Credit Requirement</th>
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Base Retail Sales, Gemini, Moapa & Southern Bighorn

SPPC RPS Compliance Outlook
Gemini, Moapa & Southern Bighorn
50% RPS, Base Retail Sales

- •• Overall Credit Requirement (kPCs)
- ■ Total kPCs (w/o Placeholders)
- ■■ Total kPCs (w/ Placeholders)

Projected RPS credit short-fall assuming no new projects >>

2024
### Base Retail Sales, Gemini, Moapa & Southern Bighorn SPPC

<table>
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<th>MW</th>
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**Total SPPC**

| Total | 1,785.0 | 1,785.0 |

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Base Retail Sales, Gemini, Moapa & Southern Bighorn

### Sierra Pacific Power - Projected Portfolio Energy Credits by Year and Type

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<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked + Pool Repayments or (Deficit Carry Forward)</th>
<th>Total KPCs</th>
<th>RPS Credit Requirement</th>
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Base Retail Sales, Gemini Solar Only

NPC RPS Compliance Outlook
Base Retail Sales, 50% RPS, Gemini 690 MW Only

Projected RPS credit short-fall assuming no new projects >> 2028
## Base Retail Sales, Gemini Solar Only NPC

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<th>%</th>
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**Total NPC** 3,940.0 3,940.0

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

---

**Base Retail Sales, Gemini Solar Only**
## Nevada Power - Projected Portfolio Energy Credits by Year and Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases &amp; Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked or (Deficit Carry Forward) adjusted for Credits Repaid to SPCC</th>
<th>Total kPCs</th>
<th>RPS Credit Requirement</th>
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<tr>
<td>2019</td>
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Base Retail Sales, Gemini Solar Only

SPPC RPS Compliance Outlook
Base Retail Sales, 50% RPS, No Projects

Projected RPS credit short-fall assuming no new projects >>

2024
### Base Retail Sales, Gemini Solar Only SPPC

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<td>2030</td>
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</table>

| Placeholder > PPA Geo NN 25 MW (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV NN 25 MW Tracking (3X) | 75.0 | 1 | 2047 | 175.0 |
| Placeholder > PPA PV NN 25 MW Tracking (4X) | 100.0 | 1 | 2049 | 100.0 |

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The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Sierra Pacific Power - Projected Portfolio Energy Credits by Year and Type

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<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc.</th>
<th>PEC Purchases, GRT</th>
<th>Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked + Pool Repayments or (Deficit Carry Forward)</th>
<th>Total kPCs</th>
<th>RPS Credit Requirement</th>
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<tbody>
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NPC RPS Compliance Outlook

Base Retail Sales, 50% RPS, Southern Bighorn Only

Projected RPS credit short-fall assuming no Placeholder Projects >> 2028
### Base Retail Sales, Southern Bighorn Solar Only NPC

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The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Base Retail Sales, Southern Bighorn Solar Only

### Nevada Power - Projected Portfolio Energy Credits by Year and Type

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<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exem Credit Obligation</th>
<th>Prior Year Banked or (Deficit Carry Forward) adjusted for Credits Repaid to SPCC</th>
<th>Total kPCs</th>
<th>RPS Credit Requirement</th>
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SPPC RPS Compliance Outlook

Base Retail Sales, 50% RPS Southern Bighorn Only

Projected RPS credit short-fall assuming no new projects >> 2024

Legend:
- Overall Credit Requirement (kPCs)
- Total kPCs (w/o Placeholders)
- Total kPCs (w/ Placeholders)
## Base Retail Sales, Southern Bighorn Solar Only SPPC

<table>
<thead>
<tr>
<th>Project</th>
<th>MW</th>
<th>COD MTH/YR</th>
<th>Split</th>
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<td>Placeholder &gt; PPA PV NN 25 MW Tracking (4X)</td>
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<td>1</td>
<td>2027</td>
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<td>Placeholder &gt; PPA PV NN 25 MW Tracking (4X)</td>
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<td>2027</td>
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<td>2028</td>
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<td>Placeholder &gt; PPA PV NN 25 MW Tracking (3X)</td>
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<td>2030</td>
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<td>Placeholder &gt; PPA PV NN 25 MW Tracking (2X)</td>
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</table>

### Total SPPC

| Total | 1,720.0 | 1,720.0 |

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Base Retail Sales, Southern Bighorn Solar Only

### Sierra Pacific Power - Projected Portfolio Energy Credits by Year and Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked Pool Repayments or (Deficit Carry Forward)</th>
<th>Total kPCs</th>
<th>RPS Credit Requirement</th>
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NPC RPS Compliance Outlook
Base Retail Sales, 50% RPS, Moapa Only

Projected RPS credit short-fall assuming no new projects >>

2028
## Base Retail Sales, Moapa Solar Only NPC

<table>
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<tr>
<th>Project</th>
<th>MW</th>
<th>COD MTH/yr</th>
<th>NPC %</th>
</tr>
</thead>
<tbody>
<tr>
<td>RFP &gt; Moapa 200 MW</td>
<td>60.0</td>
<td>12</td>
<td>2022</td>
</tr>
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</table>

| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2029 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2029 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2029 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2029 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2029 |
| Placeholder > PPA PV SN 25 MW Tracking (3X) | 75.0 | 1 | 2029 | 575.0 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (3X) | 75.0 | 1 | 2030 | 925.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2030 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2032 | 50.0 |
| Placeholder > PPA Geo NN 25 MW (4X) | 100.0 | 1 | 2033 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2033 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2033 | 300.0 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2035 | 50.0 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2037 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2037 | 125.0 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2038 | 50.0 |
| Placeholder > PPA PV SN 25 MW Tracking (3X) | 75.0 | 1 | 2039 | 75.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2040 | 25.0 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2041 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2041 | 150.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2042 | 25.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2043 | 25.0 |
| Placeholder > PPA PV SN 25 MW Tracking (3X) | 75.0 | 1 | 2044 | 75.0 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2045 | 50.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2046 | 25.0 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV SN 25 MW Tracking (4X) | 100.0 | 1 | 2047 |
| Placeholder > PPA PV SN 25 MW Tracking (3X) | 75.0 | 1 | 2047 | 675.0 |
| Placeholder > PPA PV SN 25 MW Tracking (1X) | 25.0 | 1 | 2048 | 25.0 |
| Placeholder > PPA PV SN 25 MW Tracking (2X) | 50.0 | 1 | 2049 | 50.0 |

**Total NPC**: 3,335.0

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
# Base Retail Sales, Moapa Solar Only

## Nevada Power - Projected Portfolio Energy Credits by Year and Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Energy</th>
<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Exit Credit Obligation</th>
<th>Prior Year Banked or (Deficit Carry Forward) adjusted for Credits Repaid to SPPC</th>
<th>Total KPCs</th>
<th>RPS Credit Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>3,643,522</td>
<td>111,928</td>
<td>589,446</td>
<td>785,652</td>
<td>(382,825)</td>
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<tr>
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Base Retail Sales, Moapa Solar Only

SPPC RPS Compliance Outlook
Base Retail Sales, 50% RPS, Moapa Only

Projected RPS credit short-fall assuming no new projects >>

2024
## Base Retail Sales, Moapa Solar Only SPPC

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**Total SPPC**

| Total | 1,765.0 | 1,765.0 |

The placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.
## Base Retail Sales, Moapa Solar Only

### Sierra Pacific Power - Projected Portfolio Energy Credits by Year and Type

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<th>Station Usage, Misc. PEC Purchases, GRT Credit Obligations &amp; Credit Repayments</th>
<th>Renewable Generations</th>
<th>Demand Side Management (DSM)</th>
<th>Prior Year Banked + Pool Repayments or (Deficit Carry Forward)</th>
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FALL 2018
RENEWABLE ENERGY
REQUEST FOR PROPOSALS
INCLUDING DISPATCHABLE ENERGY

Issued: October 16, 2018
Responses Due: December 10, 2018
4:00 p.m. Pacific Prevailing Time (“PPT”)

Bid Event Website: www.poweradvocate.com
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Attachment P – Proposal File Structure
1.0 OVERVIEW

1.1 Purpose and Scope

Sierra Pacific Power Company d/b/a NV Energy ("SPPC") and Nevada Power Company d/b/a NV Energy ("NPC"), collectively referred to as “NV Energy” or the “Company” are issuing this fall 2018 renewable energy request for proposals ("Fall 2018 RE RFP” or “RFP”) to interested parties with the intent of securing proposals for the acquisition of long-term dispatchable renewable energy resources ranging from 20 MW\(^1\) up to approximately 350 MW in size\(^2\), together with all associated environmental and renewable energy attributes. All references to 350 MW mean “up to” 350 MW, depending on resource type, or the equivalent of 1,012 GWh annually. Notwithstanding the above stated target, NV Energy reserves the right to vary from this target energy quantity based on evaluation of, among other things, price and risk factors of bids that are received.

This RFP bid protocol document sets forth the terms, conditions and directives of the Fall 2018 RE RFP. By responding to this RFP, Bidder agrees to be bound by all the terms, conditions, and other requirements stated under the RFP, including any modifications made to it by NV Energy prior to Bidder’s submission of its proposal(s). Bidders will be notified of any such modifications prior to the proposal submission deadline.

1.2 General Renewable Energy Resource Types and Ownership Structures

NV Energy will consider qualified proposals from Bidders who currently own or have legally binding rights to develop acceptable renewable energy generating resources (including associated substation, transmission/distribution lines, water and gas lines, and telecommunication systems, as applicable) with a minimum net power production capacity of 20 MW. Bidders are required to provide proposals for renewable energy together with all associated environmental and renewable energy attributes as a bundled product, in accordance with this RFP bid protocol document. While this RFP is not renewable energy technology-specific, the Company will not

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\(^1\) As used herein, MW refers to the capacity at the point of delivery, alternating current.
\(^2\) Actual size will be dependent on resource type (i.e. solar, wind, geothermal, etc.).
consider demand side, energy efficiency, distributed generation, or portfolio energy credit ("PC")-only proposals.

This Fall 2018 RE RFP is applicable to the purchase of electrical energy from qualifying renewable energy facilities as defined in Nevada Revised Statutes ("NRS") Sections 704.7315, 704.7811 and 704.7815, and pursuant to Nevada Administrative Code ("NAC") Sections 704.8831 through 704.8893. NV Energy is seeking proposals that are compliant with existing Nevada renewable portfolio standards and that provide resource diversification value at competitive prices. As described in greater detail below, the Company will consider proposals based on a variety of structures and resource types.

Under this RFP, acceptable renewable energy resource types include solar, geothermal, wind, biomass, and biogas technologies. Acceptable ownership structures for long-term renewable energy resources include power purchase agreements, asset purchase agreements for certain existing renewable energy resources, and build transfer agreements.

The Fall 2018 RE RFP requires projects to be capable of delivering energy to serve load in the Company’s retail service territory. (http://www.oasis.oati.com/NEVP/). Bidders may bid a renewable energy resource in the form of any of the products listed in Table 1 below. Certain pro forma agreements relating to acceptable ownership structures for qualifying renewable energy resource types are included as attachments to this RFP bid protocol document.

1.3 Battery Energy Storage Systems

In addition to the 350 MW target energy quantity, NV Energy will consider supplemental battery energy storage systems ("BESS") that are eligible for the Investment Tax Credit ("ITC") and that are associated with Bidder’s proposed renewable energy resource.

For BESS added to an existing renewable resource under contract with NV Energy BESS system, proposals must have a power output of 25% (SPPC) or 35% (NPC) of the renewable resource capacity for four hours with a non-degrading profile3. Bidders need only consider BESS

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3 For example, a 50MW renewable facility would have a BESS of 12.5 MW and 50MWh. Bidders may include in their proposals other BESS capacity and duration ratios however for the purposes of scoring and ranking bids, only the ratios above will be evaluated.
systems as a system capacity resource with a maximum of three hundred and sixty five (365) equivalent cycles per year. For purposes of this RFP, BESS systems are not considered a renewable energy resource or a generating facility.

For BESS proposed along with a new renewable resource, Bidder has discretion in sizing the BESS to meet the delivery and performance requirements of the Power Purchase Agreement for Renewable-Dispatchable Generating Facility.

1.4 Acceptable RFP Products

NV Energy is seeking the following products/categories of resources, located in Nevada, as outlined in more detail in Sections 2.8 through 2.10 below:
Table 1 – RFP Products

<table>
<thead>
<tr>
<th>Product</th>
<th>Bid Option</th>
<th>Category: A</th>
<th>Category: B</th>
<th>Category: C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Renewable ¹</td>
<td>Renewable + Storage ¹</td>
<td>Storage Only ²</td>
<td></td>
</tr>
<tr>
<td>Existing Generating Facility: ³</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>PPA</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>APA ⁴, ⁷</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Storage at Existing NVE Contracted Renewable Energy Project: ⁶</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>PPA ⁸, ¹⁰</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>BTA ⁵, ⁸</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Project:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>PPA ⁸, ⁹</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>BTA ⁴, ⁵, ⁷, ⁸</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
</tbody>
</table>

Table Footnotes:

¹ All renewable energy must include unencumbered PCs.
² NV Energy will consider minimum capacities as stated above with a one to four power to energy (MW:MWh) ratio for energy storage options as capacity replacement.
³ Proposed projects must not be currently contracted with NV Energy.
⁴ Only solar, solar with energy storage, wind, or wind with energy storage structures will be considered. Note that the pro forma agreements attached as Attachments D and E are tailored for specific technologies and structures; conforming changes will be required for alternative technologies/structures.
⁵ Proposed projects must be constructed to NV Energy engineering, procurement and construction (“EPC”) standards.
⁶ The Large Generator Interconnection Agreement may require action by Bidder to add energy storage. Energy storage dispatch, when paired with renewable energy generation, must not exceed the interconnection agreement’s capacity.
⁷ Renewable energy projects requiring a shared facilities agreement will not be considered.
⁸ Only ITC-eligible energy storage will be considered.
⁹ Storage is only applicable if PPA bid includes Full Requirements Period Product. See Section 2.8 below and pro forma PPA.
¹⁰Existing PPA will be amended to incorporate the storage terms from Attachment C.

Bidders are invited to submit multiple proposals, incorporating combinations of the products and categories that allow for cost savings.

The renewable energy resources and/or BESS system options must be integrated into the NV Energy system as a network resource for serving load in NV Energy’s balancing authority
area. Proposals must allow for a commercial operation date on or before December 31, 2023.
Proposals must have a point of delivery already identified, and connect directly to NV Energy’s system. Bidders must demonstrate, through documentation of the completed process milestones that a Large Generator Interconnection Agreement (“LGIA”)⁴ is in place or will be in place that allows for the proposed commercial operation date.

Bidders may submit proposals for any acceptable renewable energy resource in the form of a PPA having a term of fifteen (15) years and twenty-five (25) years. Bidders are encouraged to include BESS in their proposals. Any PPA for BESS systems shall have a term matching that of the renewable PPA⁵. PPA proposals are required to include purchase options in favor of NV Energy for the renewable energy resource, including all energy, capacity and associated environmental and renewable energy attributes, which are exercisable (a) at the sixth, tenth, fifteenth and twentieth (if applicable) years following the commercial operation date of the renewable energy resource, and (b) at the end of the term of the PPA⁶. PUCN approval would be required prior to NV Energy exercising any such purchase option. Bidders may also bid any of the other products and structures reflected in Table 1.

2.0 GENERAL INFORMATION FOR THE FALL 2018 RE RFP

2.1 General Information

NV Energy is seeking proposals for renewable energy resources with the target energy quantity set forth in Section 1.1 of this RFP. NV Energy will evaluate the proposals based on pricing as well as other criteria, including: (a) the greatest economic benefit to the State of Nevada; (b) the greatest opportunity for the creation of new jobs in the State of Nevada; (c) the best value to NV Energy’s customers; (d) the financial stability of the Bidder and the ability of the Bidder to financially back the proposal and any warranty or production guarantee (all subject to the jurisdiction of the United States courts and fully enforceable in United States courts); and (e) conformance to the bid criteria. NV Energy may elect to select less than the product quantity, more

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⁴ An LGIA is applicable to facilities with a net generating facility capacity of greater than 20 MW.
⁵ If the BESS is proposed at an existing NV Energy contracted site, the BESS term must not extend beyond that of the renewable contract.
⁶ Per the PPA Pro Forma
than the product quantity, one proposal, multiple proposals or no proposals at all as a result of this RFP.

All proposals submitted to NV Energy pursuant to this RFP become the exclusive property of NV Energy and may be used by NV Energy as it deems appropriate. As part of the RFP process, Bidder is required to sign a Confidentiality Agreement in the form provided in Attachment A to this RFP. However, Bidders shall have no expectation of confidential treatment of the executed agreement(s) which will be submitted to the PUCN and become available to the public. NV Energy will only consider as confidential those portions of a Bidder’s proposal clearly marked “Proprietary and Confidential.” Bidders should only mark information as proprietary and confidential that is actually proprietary and confidential. NV Energy will evaluate such marked information and determine, in its discretion, whether or not the information should be deemed as proprietary and confidential.

A proposal may be subject to discovery and disclosure in regulatory or judicial proceedings, including those initiated by a party other than NV Energy. Bidders may be required to justify the requested confidential treatment under the provisions of a protective order issued in such a proceeding. NV Energy may disclose proprietary and confidential information in the course of such proceeding without further notice to Bidders as required by law. If required by an order of the PUCN or any other governmental authority, NV Energy may provide the confidential information without prior consultation or notice to Bidders. Such information may also be made available under applicable state or federal laws to regulatory commission(s), their staff(s), and other governmental authorities having an interest or jurisdiction in these matters without further notice to Bidder. The Company also reserves the right to release such information to any contractors for the purpose of providing technical expertise to the Company. Under no circumstances will NV Energy, or any of its affiliates, officers, directors, employees, contractors, consultants, agents or representatives, be liable for any damages resulting from any disclosure of a Bidder’s claimed confidential information, whether such disclosure is made during or after the RFP process.

Bidders will be required to submit bids electronically to the Company using PowerAdvocate, which is accessible via [www.poweradvocate.com](http://www.poweradvocate.com). Accordingly, Bidders are
expected to provide a response in each data field represented. The “free text” data field accepts responses that are approximately 1,000 characters. Also, in these fields, Bidders should avoid special formatting and characters, as these can inflate the character count unnecessarily and result in a saving error. In this instance Bidders should simply remove any special characters and formatting, or shorten the answer to save successfully. Bidders should also fill out Excel spreadsheets and provide attachments, to the extent requested by the Company.

2.2 RFP Schedule

NV Energy has established the target schedule for this RFP as shown in Table 2 below. NV Energy reserves the right to amend the target schedule at any time.

<table>
<thead>
<tr>
<th>RFP Event</th>
<th>Target Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Launch RFP</td>
<td>October 16, 2018</td>
</tr>
<tr>
<td>Pre-Bid Conference and Webinar</td>
<td>October 30, 2018</td>
</tr>
<tr>
<td>Bidder Questions Deadline (1pm)</td>
<td>December 5, 2018</td>
</tr>
<tr>
<td>Bids Due (4pm)</td>
<td>December 10, 2018</td>
</tr>
<tr>
<td>Bid Fees Postmark Deadline</td>
<td>December 12, 2018</td>
</tr>
<tr>
<td>Initial Shortlist Issued</td>
<td>January 21, 2019</td>
</tr>
<tr>
<td>Best and Final Pricing Due</td>
<td>January 25, 2019</td>
</tr>
<tr>
<td>Final Shortlist Issued</td>
<td>February 11, 2019</td>
</tr>
<tr>
<td>Contract Negotiations Conclude</td>
<td>March 18, 2019</td>
</tr>
<tr>
<td>Execution of Contract(s)</td>
<td>March 21, 2019</td>
</tr>
<tr>
<td>PUCN Filing for Approval</td>
<td>April 1, 2019</td>
</tr>
<tr>
<td>PUCN Approval Timeline (up to 165 Days)</td>
<td>September 13, 2019</td>
</tr>
<tr>
<td>Commercial Operation Achieved On or Before</td>
<td>December 31, 2023</td>
</tr>
</tbody>
</table>

2.3 Registration

All parties interested in submitting a bid in response to this RFP must complete and submit a Bidders Registration and Contact Information Form located on the website for this RFP, which
can be accessed at www.nvenergy.com/RFPFall18. Bid numbers will be self-assigned as directed under Section 3.3. Parties registering for this RFP must include both a primary and alternate point of contact and identify one lead negotiator from your organization who will be available to discuss any questions specific to your proposal. This information should be entered in the Corporate Information tab/worksheet of Attachment G.

2.4 Contact Information, Questions, and Answers

This RFP can be accessed at www.PowerAdvocate.com. All communications between Bidders and NV Energy regarding this RFP will be done using PowerAdvocate as the messaging system. Communication through this system will be monitored by the Company. Communications with NV Energy personnel regarding this RFP outside of the PowerAdvocate system is grounds to disqualify a Bidder’s submission. Any response submitted by mail, facsimile, or email will not be accepted. Questions submitted by Bidders through PowerAdvocate, and Company responses, will be made public and available to all Bidders during the RFP process. At any time during the RFP, a Bidder may log into www.PowerAdvocate.com, download the communications, complete the online datasheets information and upload responses. NV Energy requires that all questions concerning this RFP be submitted by 1:00 p.m. (PPT) on December 5, 2018. Questions submitted after this time may not be answered.

2.5 Proposal Submittal Instructions

Submitted proposals must be organized in the manner described in Section 3.0 of this RFP and signed by a representative of Bidder who is duly authorized to submit the offer contained in the proposal on behalf of Bidder. Each proposal should specify the self-assigned bid number (see Section 3.3).

Bidders will be required to submit both parts of the proposal (as detailed in Section 3.0) through PowerAdvocate. Part One of Bidder’s proposal, as detailed in Section 3.1 below, will be utilized by NV Energy’s credit group in completing a credit review of each Bidder.

In order to consistently analyze responses to this RFP, Bidders are required to prepare their submission within the outlined format. Responses not complying with the format requirements may be considered non-conforming and may be disqualified at the discretion of the Company.

For a proposal to be considered by NV Energy, the proposal must be fully uploaded into PowerAdvocate by 4:00 p.m. (PPT) on December 10, 2018. Proposals, or parts thereof, received
after 4:00 p.m. (PPT) on December 10, 2018, will not be accepted. Bidders are strongly encouraged to complete forms and begin uploading files hours in advance of the deadline.

2.6 Bid Fee

Each Bidder must submit the required Bid Fee(s) to NV Energy, by certified check or cashier’s check made payable to “Nevada Power Company d/b/a NV Energy” (for BESS system projects in southern Nevada) or “Sierra Pacific Power Company d/b/a NV Energy” (for all other projects) at the address listed below. The check must reference the Fall 2018 RE RFP and Bidder’s bid number(s). The aggregate Bid Fee (as determined below) for each Bidder must be postmarked within two (2) business days of submitting the proposal(s) in PowerAdvocate. Bidder’s proposal(s) will not be considered if Bidder fails to submit timely the required Bid Fee(s).

Address for Delivery of Bid Fee:

NV Energy
Renewable Energy & Origination, Attention – R. Mitchell
Mail Stop 13
P.O. Box 98910
Las Vegas, Nevada 89151-0001

OR

NV Energy
Renewable Energy & Origination, Attention – R. Mitchell
Mail Stop 13
6226 W. Sahara Avenue
Las Vegas, NV 89146

The required amount of the Bid Fee for each Proposal is as follows:

(1) $10,000 for each proposal; and

(2) $2,500 each, for up to two additional pricing options.

If Bidder is proposing a PPA, pricing is required for both a 15-year term and a 25-year term, or for BESS only bids, term lengths of 15-year and 20-year.\(^7\) This requirement for two term options does not require an additional bid fee. In this case, and at Bidder’s discretion, Bidder may submit two pricing options under each of the term options at no additional cost.

\(^7\) For Product 3C, the term length should may not exceed the remaining term under the existing contracted PPA.
For a bid fee adder of $2,500 for each option, APA, BTA and PPA bidders may propose up to two (2) additional pricing options for a single project/proposal. Those alternatives may include changes in pricing escalators, or equipment (e.g. different panels), with all other terms of the proposal being identical under the same base fee. Alternative project sizing and more than two additional pricing options would be considered separate projects and require a separate bid fee.

A separate Attachment G must be submitted for each pricing option. Data contained in Attachment G includes cost model inputs. Model outputs are used in determining the project shortlist. Pricing options included within the proposal, but not in an Attachment G will not be considered. If a BESS system is proposed along with a new renewable energy resource, include both in one Attachment G. Follow the proposal numbering and file naming convention in Section 3.3 of this RFP bid protocol document (e.g., the proposal number for the initial Attachment G would be 1.0, and the second pricing option for the same proposal would be 1.1).

The Bid Fees will be used to cover the costs incurred by NV Energy in analyzing the proposals, including the costs of any technical consultants. Any such costs that are not covered by the Bid Fees will be recovered through fees assessed on Bidders of successful proposals (the “Success Fees”). The Success Fees will be determined by NV Energy once the final amount of Bid Fees and Company costs are known, provided that in no event will a Success Fee exceed $250,000 per successful proposal. THE BID FEE IS NON-REFUNDABLE. AFTER SUBMISSION OF BIDDER’S PROPOSAL, THE BID FEE WILL NOT BE REFUNDED UNLESS THE PROPOSAL IS WITHDRAWN PRIOR TO THE SUBMITTAL DUE DATE, THE PROPOSAL DOES NOT MEET THE MINIMUM ELIGIBILITY REQUIREMENTS AND THAT DEFICIENCY CANNOT BE CURED, OR THE PROPOSAL IS REJECTED FOR ANY OTHER NON-COMPLIANCE PRIOR TO COMMENCEMENT OF THE SHORTLISTING ANALYSES.

2.7 Minimum Eligibility Requirements for Bidders

In addition to meeting the proposal organization requirements in Section 3, all Bidders must comply with certain minimum eligibility requirements to have their proposals considered in this RFP. Failure to meet the requirements of bulleted items a) through l) will result in rejection of the proposal. Further, any proposal may be deemed non-conforming, and may be rejected by NV Energy, as a result of items m) through ee) of the following:
a) Failure to submit the full proposal in PowerAdvocate by the due date and time, except where failure was caused by a technical issue with PowerAdvocate.

b) Proposal has failed to specify all pricing terms, and include them in Attachment G.

c) Failure to permit disclosure of information contained in the proposal to (i) NV Energy’s employees, contractors, consultants, agents or representatives, (ii) relevant regulatory authorities and other governmental authorities, or (iii) non-bidding parties that are party to regulatory proceedings, under appropriate confidentiality agreements.

d) Failure to provide an official System Impact Study, Facilities Study or LGIA issued by the NV Energy transmission provider.

e) Bidder fails to demonstrate adequate site control for the proposed project, including access to the site, as evidenced through an executed and legally binding title, lease agreement, lease-option agreement, right-of-way, and/or easement issued by the fee owner or the applicable state or federal land resource agency.

f) Project is not physically located within the state of Nevada.

g) Any attempt to influence NV Energy in the evaluation of the proposals outside the solicitation process.

h) Any failure to disclose the real parties in interest in the proposal submitted.

i) Collusive bidding or any other anticompetitive behavior or conduct.

j) Bidder or project being bid is involved in bankruptcy or other insolvency-related proceedings.

k) Failure to provide a copy of Bidder’s executed Voluntary Consent Form, as submitted directly to the transmission provider, in the form provided in Attachment B of this RFP.

l) Any proposal, under a partnership arrangement, that does not include evidence documenting the legal and binding partnership with an effective period that extends well beyond the expected contract execution date stated in Table 1 (RFP Schedule).

m) Any of Bidder, its proposed prime contractor, or any material subcontractor has an Occupational Safety and Health Administration recordable incident rate greater than 1.5 in the last five (5) years or has had any fatalities on projects in the last three (3) years. Please provide relevant supporting documentation.

n) Bidder, or any affiliate of Bidder, either (i) is in current litigation or arbitration with NV Energy or an affiliate of NV Energy, with the dispute having an amount in controversy in excess of one million dollars, (ii) has, in writing, threatened litigation against NV Energy or an affiliate of NV Energy, with the threatened dispute having an amount in controversy in excess of one million dollars, or (iii) is currently adverse to NV Energy in any material regulatory proceeding before the PUCN or any other governmental authority, without regard to the amount in controversy.

o) Bidder fails to address satisfactorily both the price and non-price factors, as discussed in more detail in Section 5 of this RFP.

p) Failure of Bidder’s authorized officer to sign the proposal.
q) Any matter materially impairing Bidder, its proposed prime contractor, any major subcontractor or the project itself, including any matters impairing the output of the generating resource or its energy or environmental attributes.

r) Failure to adhere to Approved Vendors List (Attachment K).

s) For wind: failure to provide one year of viable wind data utilizing at least two anemometers for any wind project to support capacity factors submitted and failure to provide a third party wind study or equivalent to support the expected capacity factor of the project.

t) For geothermal: failure to provide a minimum of one production well and one injection well flow results to support the viability and capacity of the geothermal resource.

u) For solar: failure to provide Tier 1 solar panel manufacturer resource and technology along with a third party resource assessment report (i.e. PVsyst) to support the expected capacity factor.

v) For biomass: failure to provide a letter of intent with a biomass fuel source for a period of ten (10) years or greater along with a third party resource assessment report supporting the expected capacity factor.

w) For biogas: failure to provide a resource assessment report supporting the expected capacity factor. Report to include at a minimum, history of landfill, total volume permitted, volume filled, estimated closure date, organic fraction of the municipal solid waste, moisture levels, temperature and pH of the waste, future waste receipt, increase or decrease and average rainfall in the area.

x) For BESS systems: failure to demonstrate qualification for the ITC, failure to meet all requirements identified in Table 1, failure to identify the renewable energy resource, or failure to provide detailed description of required shared facilities and/or equipment with the associated renewable energy project (BESS-only proposals).

y) Failure to provide evidence of adequate development rights, including water rights and associated calculations demonstrating adequate water requirements, permits and information regarding water sources and well systems to support construction and operational phases for each resource. Bidders will also provide all executed contracts or other such documentation (example, water transmission plans, private transactional documents to support the required water rights, etc.).

z) Failure to identify any and all shared facilities and/or equipment with a third party or under a separate agreement.

aa) For APA or BTA: failure to provide cash flow values required during the development, construction, and operations phase for each resource, including, with respect to build transfer agreements, values and schedules for the EPC Agreement and O&M Agreement. Or completion of cash flow table in Attachment G (Price Input tab).

bb) Failure to submit an acceptance of the applicable pro forma agreement(s) as written, or a comprehensive mark-up, including comments and revisions, to the applicable pro forma agreement(s) and related exhibits. See Section 3.2.10 for further information.
cc) Failure to submit "audited" financial statements and footnotes for prior three (3) years. If Bidder does not have audited financials, Bidder must provide equivalent financials or the audited financials of the nearest level parent company.

dd) Failure to complete Attachment G in its entirety for each bid and pricing option.

e) Failure to comply with or satisfy any other requirements specified in this RFP or any attachments hereto, including any requirements in connection with the pro forma agreements and any exhibits thereto.

Evaluation of proposals will follow the process discussed in Section 5. Evaluations to determine the final shortlist of Bidders are targeted to be completed as specified in Section 2.2. NV Energy may choose to engage the final shortlist of Bidders in further discussions and negotiations. Any such discussion or negotiation may be terminated by NV Energy at any time for any reason.

2.8 Proposal for Power Purchase Agreement for Dispatchable Energy and BESS Systems

NV Energy will consider qualifying proposals to enter into power purchase agreements ("PPAs") for renewable energy resources, renewable energy resources with BESS systems and BESS systems added to an existing renewable resource in accordance with the requirements of Table 1 and in the form attached as Attachment C to this RFP. Product 3C will require an amendment to Bidder’s existing PPA to incorporate the storage product. The term length for Product 3C may not exceed the remaining term under the existing PPA.

Dispatchable Energy PPA. Any proposed PPA for renewable energy resources shall have a term of fifteen (15) or twenty-five (25) full contract years. Bids shall include pricing for the renewable dispatchable facility. Product 5A is a dispatchable renewable resource that does not include BESS and is priced with a single dollar per megawatt-hour. Product 5B is a dispatchable renewable resource that includes BESS and is designed to provide summer peaking energy. Product 5B has a two-tiered dollar per megawatt-hour structure which includes any and all BESS costs. The two-tiered pricing correlates to two operating periods designated as the Full Requirements Period and the Dispatchable Period as depicted in Attachment I.

The Full Requirements Period is the period consisting of June through August, hours ending 17 through 21. During this period, Company shall receive all energy capable of being
produced by the facility, subject to certain limitations based on the specified capacity factor\(^8\) applicable during the Full Requirements Period product. During the Full Requirements Period, the product rate is equivalent to six and a half (6.5) times the product rate applicable during the Dispatchable Period.

The Dispatchable Period is the entire period outside of the Full Requirements Period described above, consisting of January through May, and September through December, for all hours, and for the months of June through August, hour ending 1 through 16, and hour ending 22 through 24 as depicted in Attachment L. During this period, Buyer has the right to dispatch the Facility such that the Facility is operated at an active power level that is lower than its instantaneous maximum power potential and will utilize the facility for ancillary services up to the instantaneous maximum power potential of the facility.

Product 5A (Dispatchable PPA), 5B (Full Requirements Period PPA), 6A (Dispatchable BTA) and 6B (Full Requirements Period BTA) shall have these capabilities:

- The facility must be capable at all times of being operated, via dynamic signal, at an active power level at or below the instantaneous maximum output of the resource.
- The facility must be capable of reserving a configurable amount of capacity which is continuously available based on operator inputs.
- The instantaneous maximum potential output must be capable of being calculated and provided dynamically and instantaneously to Company.
- The facility must have Automatic Voltage Regulation functionality.
- Bidder must provide operating characteristics of the facility that support automated signal operation, including:
  - Facility capable of operating dynamically on Automated Generation Control (AGC) signal every four seconds
  - Facility minimum active power output when on AGC
  - Facility instantaneous maximum output in real time when on AGC
  - Facility provided maximum and minimum ramp rates when on AGC
  - Facility capable of providing dynamic voltage support at continuously rated maximum output while operating at a Power Factor of 0.95 leading to 0.95 lagging when on AGC
  - Facility capable of providing dynamic frequency response of up to 5% droop when on AGC
  - Facility provides hours each of the above capabilities are available

\(^8\) Bidder may specify a Full Requirements Period Capacity Factor between 65% and 75% of the renewable resource’s capacity. E.g. for a 100 megawatt solar facility and a 70% capacity factor, during the Full Requirements Period, the resource will deliver an average of 70 megawatt-hours each hour.
The PPA shall include purchase options in favor of NV Energy that are exercisable (a) in the sixth, tenth, fifteenth (if applicable) and twentieth (if applicable) years following the commercial operation date of the renewable energy resource, and (b) at the end of the term of the PPA. Bidder’s proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma PPA (Attachment C) in Microsoft Word format. Bidder’s proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date of the renewable energy resource. For purposes of this RFP, in determining the levelized cost of energy (“LCOE”) of the proposed renewable energy resource, NV Energy will include the transmission and distribution network upgrade costs identified in the LGIA that are to be borne by NV Energy. These costs are to be included in Attachment G. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and pricing evaluations.

BESS System PPA. As noted above, NV Energy also will consider qualifying proposals to enter into PPAs for BESS systems in connection with an existing renewable resource in accordance with the requirements of Table 1 and in the form attached as Attachment C to this RFP. Any proposed PPA for BESS systems shall have a term of either 15 years or 20 years but not to exceed the remaining term of the facility’s existing PPA. Bidder’s proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma PPA (Attachment C) in Microsoft Word format. Bidder’s proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date of the BESS system. For evaluating product 3C, BESS added to existing renewable resource, in determining the levelized cost of energy storage (“LCOS”) of the proposed BESS system, NV Energy will use a one to four power to energy (MW:MWh) ratio as noted in Table 1. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and pricing evaluations.

Project development security, if applicable, and operating security will be required from Bidders based on the nameplate capacity of the renewable energy resource contained in Bidder’s proposal(s). Project development security amounts and operating security amounts are non-
negotiable. The project development security, if applicable, shall be due within five (5) business days after countersignature of the PPA by NV Energy. The operating security shall be due and payable on the earlier of (a) the commercial operation date of the renewable energy resource and (b) countersignature of the PPA by NV Energy (if the renewable energy resource is then in commercial operation).

Any proposal made for the sale of renewable energy and associated environmental and renewable energy attributes, or the sale of capacity from a BESS system, must be made by Bidder with the understanding that the pro forma PPA attached as Attachment C to this RFP will be the basis for any definitive agreement between Bidder and NV Energy, and the proposal pricing must reflect the terms and conditions as set forth in the pro forma PPA.

2.9 Proposal for Asset Purchase Agreement

NV Energy will consider qualifying proposals to enter into asset purchase agreements ("APAs") for the sale of existing renewable energy resources in accordance with the requirements of Table 1 and in the form attached as Attachment D to this RFP. Bidders should note the requirement in Table 1 that any renewable energy resource proposed by a Bidder under this category must not be currently contracted with NV Energy. Bidder’s proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma APA (Attachment D) in Microsoft Word format. Bidder shall demonstrate that an active LGIA is in place and transferrable. For purposes of this RFP, in determining the LCOE of the proposed existing renewable energy resource, NV Energy will include its resource integration costs. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and pricing evaluations.

The pro forma APA contemplates that Bidder will transfer the fee title interest in the relevant site to NV Energy. If Bidder intends for NV Energy to acquire site control through other means (e.g. through a lease agreement, license or otherwise), then this fact should be addressed in Bidder’s proposal and Bidder’s comments to the form of APA must reflect the intended method by which NV Energy will acquire and maintain site control. The APA, which is specifically for the transfer of fee title, will be subject to further revisions by NV Energy in order to accommodate the change in ownership/site control.
Any proposal made for the sale of an existing renewable energy resource and associated environmental and renewable energy attributes must be made by Bidder with the understanding that the pro forma APA attached as Attachment D to this RFP will be the basis for any definitive agreement between Bidder and NV Energy, and the proposal pricing must reflect the terms and conditions as set forth in the pro forma APA.

2.10 Proposal for Build Transfer Agreement

NV Energy will consider qualifying proposals to enter into build transfer agreements (“BTAs”) for new renewable energy resources in accordance with the requirements of Table 1 and in the form attached as Attachment E to this RFP. Bidders should note the requirement in Table 1 that the applicable new renewable energy resource must be constructed to NV Energy’s Engineering, Procurement and Construction (“EPC”) standards. Bidder’s proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma BTA (Attachment E) in Microsoft Word format. For the purposes of this RFP, in determining the LCOE of the proposed new renewable energy resource, NV Energy will include its resource integration costs and the transmission network upgrade costs identified in the LGIA that are to be borne by NV Energy. These costs are to be included in Attachment G. Transmission system losses and One Nevada transmission line available capacity will be considered for both feasibility and pricing evaluations. All applicable security provisions are listed in the applicable pro forma agreement and associated attachments and exhibits.

Bidder’s proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and pricing evaluations.

The pro forma BTA contemplates that Bidder will transfer the fee title interest in the relevant site to NV Energy. If Bidder intends for NV Energy to acquire site control through other means (e.g. through a lease agreement, license or otherwise), then this fact should be addressed in Bidder’s proposal and Bidder’s comments to the form of BTA must reflect the intended method by which NV Energy will acquire and maintain site control. The BTA, which is specifically for the transfer of fee title, will be subject to further revisions by NV Energy in order to accommodate the change in ownership/site control.
The facility shall be designed to incorporate the dispatchable capabilities described in Section 2.8 for products 5A or 5B.

Any proposal made for the sale of a new renewable energy resource and associated environmental and renewable energy attributes, with or without a BESS system, must be made by Bidder with the understanding that the pro forma BTA attached as Attachment E to this RFP will be the basis for any definitive agreement between Bidder and NV Energy, and the proposal pricing must reflect the terms and conditions set forth in the pro forma BTA.

2.11 NV Energy Security and Approvals

PLEASE NOTE THAT NV ENERGY WILL NOT POST SECURITY TO SUPPORT ITS OBLIGATIONS UNDER ANY DEFINITIVE AGREEMENT. BIDDERS WHO WILL REQUIRE SUCH SECURITY FROM NV ENERGY SHOULD NOT SUBMIT A PROPOSAL UNDER THIS RFP.

NV Energy reserves the right to update, modify, or revise any or all of the terms and conditions contained in the pro forma agreements attached to this RFP. If a definitive agreement is reached with a Bidder, the agreement will be contingent on the approval of the PUCN and other governmental authorities, as required. NV Energy reserves the right to assign a definitive agreement, or assign or delegate any of its rights and obligations under a definitive agreement, in accordance with the assignment provisions contained in the applicable pro forma agreements attached to this RFP.

2.12 Performance and Reliability Standards

The performance and reliability standards for this RFP are incorporated or referenced in the pro forma agreements attached to this RFP. The Company is seeking performance and reliability standards that will, at a minimum, meet the compliance requirements set forth in NAC Sections 704.8777 through 704.8793, and provide the most value to NV Energy’s customers by ensuring the resource is meeting load and is able to provide Nevada portfolio credits to meet its compliance requirements. Such performance and reliability standards are similar to those that NV Energy has required in prior renewable energy resource RFPs but have been updated to address
changes in market circumstances and consistency in contract administration, all with the intent to ensure NV Energy’s customers are afforded reliable and cost-effective energy resources.

3.0 SUBMITTAL PREPARATION INSTRUCTIONS

All proposals must comply with the requirements specified in this Section. Specifically, Bidders must organize their written proposals according to the format specified in this Section 3, and must provide all applicable information required in Sections 3.1.1 through 3.2.11. In addition, all proposals must be submitted in accordance with the requirements set forth in Section 2.5 of this RFP. Please note, if you have submitted proposals in one of NV Energy’s previous RFPs that some requirements and organization have changed.

General Organization of the Proposal

All proposals must contain the following information and, to facilitate timely evaluation, must be organized as indicated below. The sections of the proposals must be as follows:

Part One
3.1.1. Cover Letter
3.1.2. Bidder Information

Part Two
3.2.1 Executive Summary
3.2.2 Technical Information
   3.2.2.1 Facility Description
   3.2.2.2 Site and Route Characteristics
   3.2.2.3 Land Permitting/Acquisition and Demonstrated Site Control
   3.2.2.4 Environmental Permitting and Compliance Authorization
   3.2.2.5 Construction and Operating Permits
   3.2.2.6 Benefits of the proposed project and/or BESS Systems to Nevada
3.2.3 Transmission
3.2.4 Resource Supply
3.2.5 Assurance of Generating Equipment Supply
3.2.6 Project Execution Plan
   3.2.6.1 Project Schedule
   3.2.6.2 Safety Program
   3.2.6.3 Project Controls and Reporting Plan
   3.2.6.4 Quality Control Program
   3.2.6.5 Subcontractor Strategy
   3.2.6.6 Work Site Agreement Plan
   3.2.6.7 Staffing Plan
Proposals that do not conform to the directives of this RFP bid protocol document may be eliminated for non-conformance at the sole discretion of NV Energy. All proposals should include complete responses to the parts set forth above in addition to the information provided in the relevant RFP attachments. Supporting documentation for these sections may be included separately as appendices by providing clear references to the sections concerned. Section titles should match those listed above. Attachment H (Bidder Proposal Compliance Checklist) is intended to aid Bidder in their compliance and is to be completed by inserting an “X” in column B for each completed item and returned with proposal.

If submitting a document as a separate file, the document name/reference must be stated in the written proposal (see file naming convention under Section 3.3). As an alternative, the document may be included as an appendix/attachment at the end of the written proposal, and should also be referenced within the body of the written proposal.

Supporting documentation in the form of an official document (e.g. permits, studies, applications, etc.) may be submitted as a comprehensive listing, in spreadsheet format, summarizing the pertinent aspects of the required documents. Please specify whether or not approvals have been obtained or applied for.

3.1 Part One of Proposal

3.1.1 Cover Letter

The cover letter must include all signatures necessary to approve and submit Bidder’s proposal by one or more representatives having the authority to contractually commit Bidder to

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9 If the proposal is being bid under a partnership, the partnership must be fully established, including a legally binding agreement (not a letter of intent), prior to submission of a proposal under this RFP. Each partner shall be bound to comply with the terms of this RFP and the proposal. The signature of each partner must be included on the cover letter, along with their contact information (i.e. company name, phone number, email address, etc.). The proposal must include evidence documenting the legal and binding partnership with an effective period that extends well beyond the expected contract execution date stated in Table 1 (RFP Schedule), otherwise the proposal will not be accepted.
Bidder’s offer(s) provided in the proposal. Additionally, the cover letter must also include the following declaration:

“[Insert legal name of Bidder] (the “Bidder”) acknowledges receipt of NV Energy’s Fall 2018 Renewable Energy Request for Proposals on or about October 16, 2018. Bidder makes the following representations to NV Energy:

1. All of the statements and representations made in this proposal are true to the best of Bidder’s knowledge and belief;
2. Bidder possesses a legally binding agreement(s) or option(s) to possess all necessary land rights for sufficient site control to undertake development of the project as set forth in the proposal, including ingress and egress to and from the site;
3. Bidder possesses or will possess all necessary water rights for construction and ongoing maintenance of the project through the term of the agreement;
4. Bidder has obtained, or can demonstrate how it will obtain, all necessary authorizations and approvals that will enable Bidder to commit to the terms provided in this proposal;
5. This proposal pertains a renewable energy system, including environmental and renewable energy attributes, from a renewable energy system. The renewable energy system will meet the requirements of NRS § 704.7315, § 704.7811 and § 704.7815; and NAC § 704.8831 to 704.8893; and the generating facility is or will be qualified as a renewable energy system in accordance with NRS §704.7801 to 7828; and the associated regulations promulgated by the PUCN;
6. Bidder and its legal counsel have reviewed the pro forma agreement(s), and Bidder’s provided mark-up(s) of the applicable pro forma agreement(s) reflect all of the now known issues that Bidder may have, or revisions that Bidder intends to request, with respect to the applicable pro forma agreement(s);
7. Bid pricing is based on the terms of the pro forma prior to the markups; and
8. This proposal is a firm and binding offer, for a period of at least 220 days from [insert date of letter/bid submittal]."
3.1.2 Bidder Information

In this Section Bidder should provide the following information:

- **Organization Structure:** Profile of Bidder’s organization and its ownership structure (including direct ownership and ultimate parent company, which can be in the form of a diagram);

- **Equivalent Development:** Description (including total nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and BESS systems, if applicable, of the same technology and equivalent or larger capacity proposed in the proposal which were successfully and fully developed (from start to finish), including land/property acquisition, permitting, construction, and placement into commercial operation by Bidder; not to include projects acquired after start of development;

- **Equivalent Ownership/Operation:** Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and BESS systems, if applicable, of the same technology and equivalent or larger capacity proposed in the proposal which are currently in service and owned or operated by Bidder (and not otherwise set forth in response to the above request);

- **Similar Development:** Description (including total nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and BESS systems, if applicable, of any technology and equivalent or larger capacity, that have been successfully and fully developed (from start to finish), including land/property acquisition, permitting, construction, and placement into commercial operation by Bidder; not to include projects acquired after start of development;

- **Similar Ownership/Operation:** Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and BESS systems, if applicable, of any technology and equivalent or larger capacity, that
are owned or operated by Bidder and currently in service (and not otherwise set forth in response to the above request);

- Other Projects: Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and BESS systems, if applicable, of any other similar projects not otherwise set forth in response to the above requests;

- Nevada Development Experience: Bidder’s pertinent experience developing (i.e. siting, routing, acquiring land rights, permitting, transmission, telecommunications, and other associated project components) similar or comparable types of projects, within the state of Nevada;

- Federal and Tribal Lands Experience: Bidder’s pertinent experience in developing (i.e. siting, routing, acquiring land rights, permitting, transmission, telecommunications and other associated project components) similar or comparable types of projects, on federal or tribal lands (i.e. Bureau of Land Management or Bureau of Indian Affairs, respectively) within Nevada and/or other states within the United States;

- Licensing: Bidder’s Nevada contractor’s license information; and

- Litigation: Any current litigation that Bidder, or any of its subsidiaries (including any off-balance sheet entities in which Bidder has an interest) is involved in regarding an energy generating facility or an energy supply contract.

Note: Bidder contact and corporate information is to be provided in Attachment G under the “Corporate Information” tab/worksheet.

As evidence of financial capability to carry out its obligations explicitly articulated or implied in the proposal, the following information must also be included in this Section\(^{10}\) of the proposal for Bidder’s company, any parent company and any partners\(^{11}\) involved with the generating facility or BESS system, and all appurtenant facilities, proposed in the proposal:

- Current bond ratings, if any;

- Current rating agency ratings or reviews, if any;

\(^{10}\) See related Section 3.2.6.8, Financing Plan, under Project Execution Plan

\(^{11}\) See footnote under Section 3.1.1.
Audited financial statements and footnotes from the last three (3) years. If Bidder does not have audited financials, Bidder must provide equivalent financials or the audited financials of the nearest level parent company;

- If financing has not been secured for the proposed project, provide information demonstrating that project financing can be secured, including references to lenders from other project financings who have a potential interest in the proposed project;

- If a guarantee of support is to be provided by an affiliate of the Bidder that affiliate must provide the above financial information and a guarantee that is enforceable in the United States;

- Provide information on the number of projects that Bidder has received financing on within the last three years for: 1) similar technology; and 2) similar or larger capacity;

- Describe any bankruptcy proceedings that Bidder, its direct affiliates or the proposed project is involved in, including current status and expected outcome; and

- Other financial information that would be pertinent to NV Energy’s evaluation of Bidder’s financial capability.

NV Energy's Credit Department will analyze the required financial criteria to determine, in its sole discretion, Bidder’s financial capability to successfully implement its proposal, and may require the provision of credit support in connection with the definitive agreements.

3.2 Part Two of Proposal

3.2.1 Proposal Executive Summary

The Executive Summary should highlight the content of the proposal and features of the offer broken down by resource and site. Each resource and site description must include the commercial operation date, the amount of energy being offered, the type of energy being offered (e.g., wind, solar, geothermal, etc.), a general description of the pricing proposal, the status of interconnection, a summary description of the transmission and telecommunication interconnection with location and route for the project to connect to the NV Energy transmission system, a summary description of project water supply agreement(s) and plans for water delivery/use, a summary description of land and environmental permitting including any major land constraints and/or natural resource concerns, description of current land rights, proposed land
rights to be acquired and any other pertinent land right information whether federal, state, local or private and whether the overall project facilities (e.g. generation, transmission/distribution, access roads, water/gas pipelines, telecommunication systems, etc.) are currently operational, in construction, or in development. In addition, this section should identify any material government incentives that are being sought in connection with the proposal.

3.2.2 Technical Information

Bidders must provide technical information regarding the proposal as described below. Attachment G, provided as a separate Microsoft Excel file, must be completed in its entirety and in accordance with the corresponding instructions in order for proposal to be considered in conformance. A separate Attachment G must be submitted for each bid/pricing option. Attachment G is used for modeling and scoring. Do not modify the file other than to provide responses in the yellow input cells. Complete the file in full and avoid inserting comments where a value is expected. Please note that alternative offers within the written proposal, without a corresponding Attachment G, will not be considered for initial shortlisting. If the project is bid using photovoltaic ("PV") technology, the plant capacity and pricing should reflect the facility’s AC MW rating.

Responses under the Non-Price Input worksheet of Attachment G are to be concise with details provided in Part Two of the proposal. Do not simply refer to the proposal document, provide a summary response to each question. Column E of the worksheet should include proposal page/section references where the detailed information is located, as applicable. It is to provide references to the detailed information/clarifications provided under Part Two of the proposal, and is not acceptable, on its own, as a response to a question. Responses under the Non-Price Input worksheet will be scored.

Attachment G, as provided within this protocol document, contains an outline of the Microsoft Excel file that is to be completed for each bid/pricing option.

In addition, Bidder must provide the following information describing the generating facility and/or BESS system, as well as all appurtenant facilities (as further described in Sections 3.2.2.1 through 3.2.2.5):

- Facility and Equipment Description
- Site and Route Characteristics
3.2.2.1 Facility and Equipment Description

Bidder must include a description of the generating facility and/or BESS systems as well as all appurtenant facilities forming the basis of the proposal to NV Energy. All facilities should be included in the description (e.g. gen-tie line(s), roads, affected NV Energy substation(s), water lines and source, gas lines, etc.), including identifying and describing any and all facilities and/or equipment shared with a third party or under a separate agreement. This Section, along with Attachment G, should also include information related to the type of plant, configuration, general layout diagrams, preliminary site plan showing site boundaries and plant layout, single-line diagram including metering scheme (see Attachment O for examples), resource type (e.g. wind, solar, geothermal, etc.), nameplate capacity rating (MW AC), net plant capacity (MW AC), annual net output (MWh), net output for each hour of the year (MWh), projected capacity factor, proposed in-service date, and the current or contemplated major equipment providers. See Section 3.2.5 regarding major equipment providers and the approved vendors list (Attachment K). In addition, provide information, including technical specifications, for the major equipment that will be used in this project. To demonstrate commercial use at a similarly sized, and environmentally comparable site, explain how many similar projects the equipment has been used in, or identify if it is a first-of-its-kind scale. Demonstrate or explain quality of materials that will be used in relation to competitor materials, if applicable. If available, provide a third party, independent engineer’s report that verifies the performance of the proposed equipment.

If the proposal is based on an existing generating facility, Bidder must provide historical data (a) for the last three (3) years, or (b) if the age of the generating facility is less than three (3) years, from when the generating facility was built. Existing generating facility information must also include the historical production schedule, net output rating (MW AC), capacity factor, equivalent availability, forced outage rate, scheduled outage rate, deratings, and the forecasted five (5) year scheduled maintenance cycle and production schedule. Any known flexibility as to the timing of the maintenance schedule must also be described. If the plant has any Trench bushings
installed on generator step-up ("GSU") transformers, explain how many, what voltage, what vintage and where they were manufactured. Bidder must also provide a general (non-confidential) description of any existing or proposed energy and capacity arrangements involving the generating facility and how they relate to this proposal.

If the proposal for sale of energy is from a new generating facility and/or BESS system that is yet to be built, Bidder must describe any feasibility studies performed for the proposed generating facility and/or BESS systems as well as all appurtenant facilities. Bidder must also describe the level of engineering completed for the generating facility and/or BESS system as well as all appurtenant facilities and the plan for equipment procurement and construction. Bidder should also identify any contractors that have been engaged to provide any of these services. Bidder should also describe any innovative technical features of the generating facility and/or BESS system as well as all appurtenant facilities, incorporating new energy technologies. Trench bushings are not permitted on GSU transformers. If innovative technical features are included, Bidder must describe any previous experience with implementation of such technical features and the level of risk involved in this application. A production profile for the generating facility must be provided showing the energy deliveries in average energy production by month and time of day. The data and evaluations provided must support the proposed level of generation and the projected capacity factor.

For BESS systems bids, Bidder must provide a description of the plant communications and control plan. The plan shall include a description and diagrams (as applicable) that demonstrate how Bidder will provide:

- BESS systems data, including state of charge, power charge/discharge status, and asset health indicators (temperature, HVAC alerts, emergency status, etc.)
- BESS system control, including limitation of charging only from renewable energy production, charge/discharge scheduling, and station service load

All information provided in this Section must be consistent with the information provided in Attachment G, which includes information required for the evaluation of the proposal as further described in Section 5.0 of this RFP.
3.2.2.2 Site and Route Characteristics

As applicable, Bidder must:

(a) Provide a legal description, including, County, Section, Township & Ranges and metes and bounds legal description with exhibit, of the generating facility site and/or BESS systems as well as all appurtenant facilities and, both a street map and the appropriate section of a USGS (or equivalent) map showing the location and boundary/route of the generating facility and/or BESS systems as well as all appurtenant facilities. The maps should show all land parcels, with parcels owned, leased or optioned by Bidder clearly marked.

(b) Provide an aerial photo and Google Earth® file of the project site showing project boundary(s), linear facility route(s), and a layout of the proposed facilities.

(c) Provide the County Assessor’s parcel number, site address, and site coordinates for all project facilities.

(d) Provide an ALTA/ACSM survey of the project site if such survey has been conducted. This survey will be required if the proposal is selected under the final shortlisting, and in accordance with the applicable pro forma agreement.

3.2.2.3 Land Permitting/Acquisition and Demonstrated Site Control

As applicable, Bidder must:

(a) Provide a list of all land parcels for the project, including current ownership.

(b) Provide a description of the legally binding lease or ownership arrangement¹² for each parcel, along with all copies, including amendments, of fully executed leases, deeds, options, purchase agreements, preliminary title reports, easements, other land rights and other documentation for private, local municipalities and state owned lands, as well as any other non-federal owned lands (e.g. Union Pacific Railroad), that are in place or contemplated for the site and all linear appurtenances (e.g., gen-tie lines, microwave facilities, access roads, substation expansions, etc.), the number of acres at the site and of all linear appurtenances, site access roads and, as applicable, water supply agreement or the plan for securing sufficient water, the waste

¹² A non-binding letter of intent to reach an agreement or an agreement that is not fully executed is unacceptable. A legally binding option agreement is acceptable.
disposal plan, fuel supply (as applicable), associated water/fuel transmission plans, or other infrastructure additions required outside of the site boundaries for the proposed project to be implemented.

(c) Specify the quantity of water required for construction and operation of the facility for the full life of the project. Provide status of necessary documents or permits required for securing sufficient water rights or other water supply, including date delivery will commence, name of water purveyor, acre-feet annually, pump rate, limitations, location of source and proximity to project, any supplemental sources, and permitting or licensing status. As applicable, explain if water right application is in permitted or certificated status. Provide copies of any permits, and agreements or letters of intent with a third-party to secure sufficient water supply.

(d) Provide all documentation of exclusive or non-exclusive site control\(^\text{13}\) and/or a description of the current status of efforts to secure such site control for all Federal Agency managed land regardless of how the land is actually held (e.g. in Trust for the Bureau of Indian Affairs, withdrawn for branch of military, Bureau of Land Management). For all federal lands, provide SF299 application packages, or agency specific application, including but not limited to, all exhibits, attachments and the Plan of Development. Provide all federal right of way offers/grants and/or option agreements, Limited/Full Notices to Proceed, or agency specific land right, etc. if already issued by the respective agencies. Provide a detailed explanation that verifies all land acquisition efforts such as, but not limited to, fees paid, option agreements, executed Tribal consent, executed Tribal Term Sheet, Bureau of Indian Affairs (BIA) consent, Military Branch approval, expected dates for approvals, executed site option(s) with ongoing option payments, unilateral right to strike on site option(s) at agreed upon price(s) over the term of the option agreement(s), any future site procurement costs, etc.).

(e) If 100% site control has already been attained, provide a detailed explanation that identifies all environmental mitigation requirements that will be required to be implemented along with estimated costs and scheduling.

\(^{13}\) A Tribal letter of intent to reach an agreement not addressed to Bidder or not accompanied by an executed Term Sheet or an agreement that is not fully executed is unacceptable. A legally binding option agreement is acceptable, provided that it includes all the terms of the lease agreement.
(f) Land Use Permits, including but not limited to Special Use Permit from local governmental agency.

(g) Provide a detailed list of all applicable state, local and federal land permits and authorizations anticipated for securing land rights for the generating facility and/or BESS systems as well as all appurtenant facilities that authorize the construction and operation of all facilities. Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing those permits and approvals.

(h) Identify important milestones and decision points in the schedule along with an explanation of how land permitting activities will be coordinated within the overall construction and development schedule.

(i) Identify and fully describe the arrangements of any and all facilities and/or equipment shared with a third party or under a separate agreement, even if the separate agreement is with NV Energy. Include any impacts to NV Energy due to such shared facilities/equipment and plans to alleviate potential negative impacts.

3.2.2.4 Environmental Permitting, Compliance and Authorization

Bidder must also:

(a) List and provide a description of all local, state and federal environmental requirements, authorizations, permits, etc., anticipated to be required in order to support the acquisition of land rights, as well as to construct and operate the generating facility and/or BESS systems as well as all appurtenant facilities in accordance with all applicable environmental laws and regulations. Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing those permits and approvals along with all associated environmental compliance tasks and activities required by any regulatory agency(s).14

(b) Describe all coordination efforts/actions already taken, or anticipated to be taken, with local, state, and federal agencies with respect to environmental permitting and regulatory compliance with a description of current status of each effort/action.

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14 See related Section 3.2.6.9, Environmental Plan, under Project Execution Plan
(c) Provide copies of all environmental permit applications with associated attachments, any environmental analysis/review documents pursuant to the National Environmental Policy Act, Endangered Species Act, National Historic Preservation Act, Clean Water Act, Clean Air Act, etc., documents/reports of any environmental surveys conducted, land/environmental constraint studies, environmental site assessments, hazardous/waste material reports or other information associated with the land(s) acquisition and land use to support the proposed generating facility and/or BESS systems as well as all appurtenant facilities.

(d) Describe any existing environmental issues of concern associated with the generating facility and BESS systems as well as all appurtenant facilities, such as site contamination, presence of waste disposal area, state or federally protected plant and wildlife species or habitats and species of concern present or potentially present, National Conservation Lands, wetlands, and any other known or potential environmental issues, with an explanation of how Bidder will address any such issues so as to maintain the ability to meet the anticipated commercial operation date and other long-term obligations of the agreement.

(e) Include any current Phase I or Phase II environmental site assessment reports/action conducted by or available to Bidder.

(f) Describe whether or not the project would potentially require any air permits, and if so, provide any air quality modeling results, and estimated air emission rates identified or expected to be included in an air permit process.

(g) Describe the land uses adjacent to and in proximity of the generating facility and/or BESS systems as well as all appurtenant facilities. Describe current or planned efforts to build local community support.

(h) Provide copies of environmental permits already successfully secured, including their associated applications and supporting documents, studies and reports.

(i) Identify important milestones, all key environmental tasks and activities, and decision points in the schedule along with an explanation of how environmental permitting and regulatory compliance activities will be coordinated within the overall development schedule, including construction and operation and maintenance.
3.2.2.5 Construction and Operating Permits

Bidder shall provide a list of permits required for construction, operation and occupancy of the proposed project. Bidder is responsible for obtaining all permits. Additionally, Bidder shall:

(a) Describe all local, state and federal construction requirements, authorizations, permits, (e.g. grading, stormwater, fencing, building, dust control, occupancy, etc.) anticipated in order to construct and operate the entire project in accordance with all applicable laws and regulations.

(b) Describe all coordination efforts and actions already taken, or anticipated to be taken, with local, state, and federal agencies with respect to acquiring the necessary construction and operations related permits.

(c) Describe any existing on-site construction issues of concern that may impact the ability to meet the anticipated commercial operation date. Include risk mitigation efforts planned to maintain the commercial operation date.

(d) Provide copies of any construction and operating permits already secured, including their associated applications and supporting documents, studies and reports.

(e) Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing all applicable state, local and federal construction and operating permits.

(f) For wind projects, include airspace and radar clearance, Federal Aviation Administration ("FAA") and Federal Communication Commission ("FCC") permit status if applicable.

3.2.2.6 Benefits of the Proposed Project to Nevada

Bidder must describe any other special expected environmental, social, or economic benefits of the proposed project, including value attributes (e.g. availability, dispatchability, scheduling, fuel diversity, hedging, ancillary services, etc.). Bidder must describe how the project will provide the creation of new jobs in the state of Nevada. In addition, Bidder must also complete the applicable economic benefits spreadsheet in Attachment G. Instructions are provided in the “Economic Benefit Input” tab. All inputs should only include direct costs and job data in Nevada.
3.2.3 Interconnection

Bidder must provide information on whether an interconnection request has been submitted to the applicable transmission provider for the generating facility, and if so, the status of such request. Demonstrate that the resource can effectively be integrated through the transmission path or as a network resource to NV Energy, and explain any transmission constraints, if known. Specify whether any ancillary services have been confirmed. As applicable, provide copies of the System Impact Study, Facilities Study and/or LGIA. Bidder will also identify the anticipated interconnection point and in-service date for the proposed generating facility and/or BESS systems. The in-service date must be as specified by the transmission provider and well in advance of the required commercial operation date in order to allow for testing.

All proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include all costs to interconnect to the transmission provider’s system. In addition, bidder shall provide a diagram of the interconnection facilities provided in the LGIA or the most recent System Impact Study or Facilities Study on the project, as completed by the transmission provider. If such transmission studies have not yet been completed at the time the proposals are submitted and will not be completed at least five business days prior to initial shortlisting, the bid will be deemed non-conforming. The interconnection costs for network upgrades will be included in the LCOE calculation. Bidders will describe interconnection costs in their proposals by disclosing that portion of costs associated with network upgrades and that portion that is facility-specific. Bidders are reminded that the cost responsibility for all transmission facilities will be pursuant to the provisions of the OATT. The Interconnection Customer is responsible for all of the Transmission Provider’s Interconnection Facilities (“TPIF”) costs. The Transmission Provider is responsible for the costs associated with Network Upgrades (“NU”) pursuant to the OATT; however, such costs will be securitized by the Interconnection Customer as provided under the provisions of the OATT. Interconnection Customer’s Interconnection Facilities (“ICIF”) are the sole responsibility of the Interconnection Customer. Due to the construction timeline, Bidders are expected to have an executed LGIA, completed facility study or, at a minimum, a completed system impact study.

If the existing renewable energy project LGIA does not already include the proposed BESS systems, the LGIA will need to be amended and restated to incorporate the BESS systems. The
Interconnection Customer specified in the LGIA will need to submit an evaluation for a material modification along with updated plant specifications and generator model data to the Transmission Provider in accordance with the applicable Open Access Transmission Tariff requirements.

Bidder will provide the executed interconnection agreement with documentation supporting completed milestones. For proposals where an LGIA has not been executed, Bidder will provide, at a minimum, the system impact study and facilities study prepared by the transmission provider.

Bidder must provide a copy of its executed Voluntary Consent in the form provided in Attachment B of this RFP. The original must be submitted directly to the transmission provider, separate from the RFP proposal, on or before submission of the proposal.

NV Energy will only consider generating facilities and/or BESS systems physically located in Nevada and capable of delivering energy to serve load in NV Energy’s retail service territory (http://www.oasis.oati.com/NEVP/).

3.2.4 Resource Supply

Bidder must provide sufficient information with respect to resource supply to provide assurance to NV Energy that the generating facility and/or BESS systems will be able to meet its projected production estimates for the full term of the PPA or, if applicable, the expected useful life of the generating facility. Provide the means and specifications to meet the dispatchability requirements. Provide any third-party resource assessment reports supporting the expected capacity factor. In addition, identify proposed manufacturers and model numbers for major equipment. In particular, the following information is requested for the different technologies:

Geothermal

- Provide a summary of all collected geothermal data for the proposed generating facility site.
- Characterize the geothermal resource quality, quantity and projected production levels.
- Provide a graph or table that illustrates the annual and monthly projection of geothermal resources.
- Describe any other existing geothermal facilities in the resource area and characterize their production and their anticipated impact, if any, on the generating facility.
Provide a minimum of one production well and one injection well flow results to support the viability and capacity of geothermal resource. For results in excess of three (3) years, summarize the results for all years and provide the detail for the past three (3) years of production well flow tests.

**Solar**

- Describe the sources of insolation data, either onsite, satellite, or a nearby station. If using a nearby station, state the exact distance from that station.
- Provide source and number of years of solar data used to support the capacity factor.
- Provide a third-party PV/Syst report or similar assessment report based on credible solar radiation meteorological data.
- Specific resource and technology, including a requirement that all bids include panels manufactured by a Tier 1 solar panel manufacturer, and inverters from a vendor on the Approved Vendors List (Attachment K).

**Wind**

- Provide a summary of all collected wind data for the generating facility site.
- Indicate where the data was collected and its proximity to the generating facility site.
- Provide one (1) year of applicable wind resource data utilizing at least two anemometers for any wind project to support capacity factors and a third-party wind resource assessment report based on meteorological tower data.
- Compare the long-term wind speeds in the area to the collected resource data at the generating facility site.
- Confirmation of wind turbine availability and size.

**Biomass**

- Describe the biomass fuel makeup and its source.
- Provide third-party resource assessment reports of available biomass fuel for the generating facility and its proximity to the generating facility. Such resource assessments should include a discussion of long-term fuel price risk and availability risk issues.
- Identify competing resource end-uses.
- Provide a plan for obtaining the biomass fuel, including a transportation plan.
- Identify any contracts or option agreements to acquire and transport the biomass fuel.
- Provide an agreement or option agreement with a biomass fuel source for a period of ten (10) years or greater.
Biogas

➢ Provide third-party resource assessment reports of available biogas fuel for the generating facility and its proximity to the generating facility. Such assessment reports should include at a minimum: history of landfill, total volume permitted, volume filled, estimated closure date, organic fraction of the municipal solid waste, moisture levels, temperatures and pH of the waste, future waste receipt, increase or decrease and average rainfall in the area.

BESS

➢ BESS systems degradation, round trip efficiency, controls, location, life, cycles, load duration, descriptions of all facilities and equipment shared with the associated renewable generation facility, and the other applicable information listed in Attachment G. Include a discussion of BESS chemistry, whether the system is alternating current (“AC”) coupled or direct current (“DC”) coupled and how degradation will be managed (e.g. overbuild, augmentation, etc.).

3.2.5 Assurance of Generating Equipment Supply

To demonstrate ability to deliver on time, Bidder must list and demonstrate that it has access to, or has completed sourcing of, the necessary major equipment, pursuant to the Approved Vendors List provided in Attachment K of this RFP, to complete the design, engineering and construction of the facility contemplated in the proposal to meet the stated commercial operation date\(^\text{15}\). Provide details of all equipment including supplier detail, make and model and any form of supply, warranty and performance commitment from suppliers. If Bidder has a preferred equipment provider that is not included in Attachment K, please identify the vendor and their experience within the United States for projects of similar technology and size, detail Bidder’s reasoning for the preference, and specify any direct experience Bidder has had with the vendor. If a contract is in place for any equipment, please identify the contracted party. Provide a mark-up of Attachment K if recommending new vendors. Attachment K will become part of the applicable pro forma agreement.

\(^{15}\) See related Section 3.2.6.4, Quality Control Program, under Project Execution Plan
3.2.6 Project Execution Plan

Bidder will provide a summary-level, site-specific project execution plan. The project execution plan will be referenced and become part of the pro forma agreement. Key elements of the execution plan are:

3.2.6.1 Project Schedule

Bidder must provide a detailed project schedule that includes the anticipated period to permit and complete the project in order to achieve commercial operation, referenced in months, following receipt of all regulatory approvals, including PUCN approvals (i.e., IRP and UEPA). This time period must allow for environmental and land right acquisition and permitting, environmental studies, mitigation and treatment, transmission construction, financing, site development, construction permitting, construction, testing, and any other development and construction requirements. Bidder must provide a milestone schedule for the proposed project, inclusive of the major development milestones listed below (as applicable):

- Major Equipment Ordered;
- Project Interconnection to Transmission System;
- All Permits Obtained for land, environmental and construction;
- All land rights acquired;
- Construction Financing Obtained;
- Construction Start;
- Environmental Compliance/Mitigation;
- Operation Date (first energy to grid); and
- Commercial Operation Date.

These milestones should be noted in number of months following receipt of all regulatory approvals, including PUCN approvals (i.e., IRP and UEPA).

Bidder also shall describe any measures to be taken to ensure the proposed schedule will be met.

Note that Bidder will be required to post security following execution of a definitive agreement and prior to the submittal of the definitive agreement for PUCN approval (i.e., IRP).
3.2.6.2 Safety Program

The development and implementation of a good safety program at the site is of paramount importance to NV Energy. Safety is a core principle of NV Energy and is a priority in every aspect of our business. The same level of safety diligence is expected from contracted parties. Bidder’s safety program must comply with or exceed NV Energy’s safety requirements, as outlined in Attachment J to this RFP. Any exceptions or comments must be noted in Bidder’s proposal. As part of its proposal, Bidder must submit its corporate safety incident report for the preceding five (5) years.

3.2.6.3 Project Controls and Reporting Plan

Bidder will submit their Project Controls and Reporting Plan, including a summary (Level II) construction schedule displaying major activities, durations and proposed sequencing which demonstrates Bidder’s proposal to achieve substantial completion prior to the operation date as listed in its proposed Project Schedule as provided under Section 3.2.7.

3.2.6.4 Quality Control Program

Bidder will provide an outline of its Quality Control Program in line with its proposal, including, in accordance with the Approved Vendors List (Attachment K), the plan for procurement of equipment.

3.2.6.5 Subcontractor Strategy

Bidder will provide detailed information as to a proposed execution plan for its proposed project, including the name and experience of anticipated major subcontractors. It is the expectation that Bidder (or an affiliate thereof) would remain primarily responsible for the obligations of Bidder regardless of whether the obligations are performed by Bidder or a subcontractor.

3.2.6.6 Work Site Agreement Plan

A pro forma work site agreement ("WSA") is attached as Attachment N to this RFP. This form may be modified based on the applicable unions and their associated master agreements. The form of WSA, as modified, or an executed WSA, is to be inserted in the applicable exhibit of the
agreement being proposed. Bidders who take exception to the terms of the WSA agreement must provide a mark-up of the agreement, including Bidder’s proposed language. In addition, a statement of acceptance of the agreement as written, or explanation of each exception must be provided within the proposal. The WSA agreement is between Bidder and the union(s).

Bidders that advance to the initial shortlist shall commence discussions with the unions immediately following notice of shortlisting. Bidders that advance to the final shortlist are required to provide weekly updates on the status of their WSA negotiations with the union(s). Bidders must provide an executed WSA, with Nevada union(s), prior to or at the time of execution of the RFP agreement. Bidder must be a signatory on the WSA. If Bidder elects to contract with an EPC, the EPC will be required to comply with the terms of the WSA.

3.2.6.7 Staffing Plan

Bidder shall provide a good faith estimate of the following (values for Nevada only):
- Number of direct jobs during construction (full-time equivalent) average and at peak construction and average salary of construction staff.
- Number of direct jobs during operation and maintenance (full-time equivalent).
- Average annual Salary of such jobs during operation and maintenance.
- Total direct payroll expenditure over the term of the agreement (e.g. 25 years).

The above estimates should match the values provided in Attachment G under the Economic Benefits Input worksheet, as applicable (i.e. Solar PV, Wind, Geothermal, etc.). If a contract is executed, these values will be stated in the regulatory filing for PUCN approval.

3.2.6.8 Financing Plan

Bidder should provide a detailed description of the financing plan for the proposed project (government, private, self-funded, balance sheet, power purchase agreement, etc.) and general description of status. If financing has been secured for the proposed project, provide commitment letter from financier.

3.2.6.9 Environmental Plan

Provide a detailed description of how Bidder will develop, permit, construct, operate and maintain the generating facility and/or BESS systems as well as all appurtenant facilities that
includes the known and anticipated environmental permits, environmental activities associated with any land and permitting efforts, and known and anticipated mitigation measures required for pre-construction activities, construction activities and post-construction activities.

### 3.2.6.10 Facility Operation and Maintenance Plan

Bidder must provide a description of the expected operation and maintenance ("O&M") plan for the generating facility and BESS systems as well as all appurtenant facilities. This information should include the following:

- Whether Bidder or affiliate will operate and manage the generating facility and/or BESS systems as well as all appurtenant facilities or will contract for O&M services. If Bidder will contract for O&M services, explain the current status of selecting an O&M contractor.
- Completed integrated solar and storage O&M term sheets and pricing for generating facility and BESS systems as well as all appurtenant facilities.
- A brief description of the basic philosophy for performing O&M including a discussion of contracting for outside services.
- Planned maintenance outage schedules.
- Plan for replacement of major equipment during the term of the contract.
- Plan for any land rights issues or environmental concerns including any post-construction environmental compliance monitoring, studies and reports as well as ongoing environmental compliance requirements during operations and maintenance.

### 3.2.7 Contract Terms and Conditions

NV Energy strongly encourages Bidders to accept the terms and conditions set forth in the applicable pro forma agreement(s) and related exhibits included as attachments to this RFP. Bidders who take exception to the terms of the pro forma agreements must provide a mark-up of the applicable agreements, including Bidder’s proposed language (not just comments). Mark-ups should be provided in Microsoft Word format. In addition, a statement of acceptance of the agreement as written, or explanation of each exception must be provided within the proposal. **Proposals without a complete mark-up or acceptance, may be disqualified.** In providing such a mark-up, Bidder should ensure that the allocation of risk in the agreement is not materially

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16 Product 3C will require an amendment to Bidder’s existing contracted PPA to incorporate the storage product. Please provide mark-ups to the storage provisions in Attachment C.
altered. NV Energy will consider the impact of the mark-up in its evaluation of the proposal. Allowances will be made for mark-ups to BESS systems provisions. Attachment K and Attachment N of this RFP bid protocol document are to be inserted in the applicable exhibits of the agreement. Note that Bidder is required to have an officer of its company certify that the applicable pro forma agreements have been thoroughly vetted, including review by Bidder’s legal counsel, and that the pro forma agreements either are accepted or the mark-ups provided by Bidder are substantially complete. See item 6 of cover letter under Section 3.1.1 of this RFP bid protocol document.

3.2.8 Other Information

Bidder should provide any additional information that will assist NV Energy in its evaluation of the proposal. The proposal should indicate whether or not other information has been provided, and specify or list (if appendage) the other information.

3.3 Bid Numbering and File Naming Convention

Bid numbers will be self-assigned by Bidder in accordance with the directives below. There is no limit to the number of proposals that may be submitted. See Section 2.6 regarding Bid Fees.

Bid numbers shall be a whole number followed by one decimal place, beginning with the number 1.0. Each subsequent proposal will have a separate sequential bid number (i.e. 2.0, 3.0, etc.). The decimal place will be used to indicate pricing options\textsuperscript{17}, necessary for Attachment G. The initial pricing option will be identified as 1.0 and the second pricing option, for the same proposal, would be 1.1\textsuperscript{18}. Bidder’s next proposal, if any, would be 2.0 with 2.1 as the second pricing option.

File names should be kept short by using abbreviations wherever possible. All required documents must use the following naming convention:

- [Abbreviated Bidder name]_[Bid number]_[Abbreviated_File_Descriptor]

\textsuperscript{17} See Section 2.6 regarding qualified pricing options, and requirement for separate Attachment G for each option.

\textsuperscript{18} For PPA bids where a 15 year and 25 year (or 15 year and 20 year for BESS) add the term length at the end of the file name (e.g. 15, 25).
For appendices, include appendix number and RFP section reference in the abbreviated file descriptor (i.e. XYZ_1.0_Part_2_Appx_1_3.2.2.1_SLD). See Attachment P (Proposal Zip File Structure) for further file naming examples.

All files related to a single bid must be compressed together and uploaded into PowerAdvocate as a single .zip file named [Bidder name abbreviated]_[Bid Number].zip (example: “NVE_1.0.zip”). Folders and subfolders for specific document types should be included in the .zip file following the directory structure/organization and folder naming convention provided in Attachment P (Proposal Zip File Structure). Documents provided in this RFP that have been modified by Bidder and any additional files provided by Bidder must apply the naming convention specified above before being compressed into the .zip file. Please note, the .zip file associated with a bid may be quite large and take some time to upload, so please plan adequate time to upload each bid’s .zip file into PowerAdvocate hours in advance of the bid submission deadline.

4.0 STANDARDS OF CONDUCT

Each Bidder responding to this RFP must conduct its communications, operations and other actions in compliance with FERC’s Standards of Conduct for Transmission Providers. Any necessary interconnection to, or transmission service on, NV Energy’s transmission system contemplated in a Bidder’s proposal will not be considered an arrangement with NV Energy’s merchant function, which is sponsoring this RFP. Such arrangements for interconnection and transmission service will be with NV Energy’s functionally separate transmission function, and therefore, absolutely no communication by a Bidder to NV Energy’s transmission function can be made through the submission of a proposal in this RFP. Any Bidder seeking to communicate with NV Energy’s transmission function personnel will have its proposal(s) summarily rejected if the attempt is not immediately withdrawn when discovered. Bidders are required to execute the Voluntary Consent Form in Attachment B to this RFP that enables NV Energy’s merchant function to discuss Bidder’s interconnection and transmission service application(s) with the transmission interconnection or transmission service provider, including, if applicable, NV Energy’s transmission function.
Bidder will cooperate with and provide information to any person or entity retained by NV Energy for purposes of evaluating Bidder’s proposal.

Bidder shall not attempt to influence NV Energy in the evaluation of the proposals outside the solicitation process.

Bidder shall not participate in collusive bidding or any other anticompetitive behavior or conduct.

5.0 EVALUATION PROCEDURES AND CRITERIA

Each proposal will be initially evaluated by NV Energy to determine the proposal’s conformance to the directives of this RFP bid protocol document and Bidder credit risk. Proposals may be eliminated for non-conformance or due to credit risk.

For each product in this RFP that passes the initial evaluation, NV Energy will conduct a two-stage process as part of its proposal evaluation and selection process leading up to selection of the preferred proposals for contract execution. In the first stage, NV Energy will conduct price, economic benefit (including job impacts) and non-price analyses, as well as a price screening methodology designed to identify the lowest cost proposals for each product. NV Energy will select a shortlist based on those proposals for each product which have the highest overall score based on an evaluation of price, economic benefit and non-price factors. In the second stage, the shortlisted proposals will have the opportunity to refresh their prices; provided, however, that Bidders will not be permitted to increase the prices initially submitted with their proposal. The final proposals will then be modeled and evaluated based on the impact of the proposals on NV Energy’s overall system costs. A more detailed description of each stage of the process is provided below.

NV Energy will conduct the two-stage evaluation and selection process independently for each of the proposals, by resource type. NV Energy will select and propose to the PUCN, for review and final approval, the proposal(s) that provide the best value to NV Energy’s customers, considering all the factors described in this Section 5.
5.1 First Stage: Price, Economic Benefit and Non Price Analysis; Development of Initial Shortlists

The price, economic benefit and non-price forms in Attachment G will be used as a model to determine individual initial shortlists of proposals, separated by type of resource (i.e., wind, solar, geothermal, biomass, biogas and BESS systems). These resource-specific shortlists will be deemed the initial shortlists for further evaluation.\(^{19}\)

In considering a proposal, NV Energy will, in addition to considering the cost to customers, evaluate the following:

(a) The greatest economic benefit to the State of Nevada;
(b) The greatest opportunity for the creation of new jobs in the State of Nevada; and
(c) The best value to customers of the electric utility.

Price factors will be analyzed to determine the LCOE or LCOS, as applicable, per MWh value of each proposal, and then ranked using the comparison metric described in Section 5.1.1 below. Price factors will recognize the value of the power associated with the delivery profile submitted in the proposal.

Non-price factors considered by the Company fall into four general categories:

1) Bidder’s project development and operational experience;
2) Technology and value attributes;
3) Conformity to the terms of the applicable pro forma agreements; and
4) Development milestones.

NV Energy intends to evaluate each proposal in a consistent manner by separately evaluating the non-price characteristics, economic benefit characteristics and the price characteristics of the proposal utilizing a proposal scorecard.

The proposal scorecard will include three factors, all of which may be viewed in Attachment G:

1) Price factor;

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\(^{19}\) See Section 3.2.2 for additional information on Attachment G.
2) Non-price factor with four primary categories; and
3) Economic benefit factor with three categories.

Each component will be evaluated separately and recombined to determine the bundled price, economic benefit and non-price score. The price factor will be weighted up to 60%, the economic benefit factor will be weighted up to 10%, and the non-price factor will be weighted up to 30%. No proposal will receive a total weighting in excess of 100%. The price, economic benefit and non-price evaluations will be added together and used to determine the initial shortlist for each resource type. The initial shortlists in this RFP will be made up of the highest scoring proposals for each resource type.

5.1.1 Price Factor Evaluation (up to 60%)

A pricing model will be used to derive the LCOE per MWh value of each proposal (Products 1A, 2A, 5A, 5B, 6A and 6B, from Table 1) based on the price factors ("Proposal LCOE"). For BESS systems, the pricing model will derive the LCOS per MWh value of each proposal (Product 3C from Table 1) based on the price factors ("Proposal LCOS"). The Proposal LCOE and Proposal LCOS may also be referred to as the proposal levelized cost value ("Proposal LCV").

For each of the products, NV Energy will utilize a comparison metric to evaluate and determine the Proposal LCV ranking for the resource-specific initial shortlists.

The comparison metric will be the Proposal LCV per MWh. The Proposal LCV will be determined by calculating the present value of the annual cost over the term, converting the present value to an equivalent annual annuity and then dividing that annual annuity by the levelized annual energy provided. The discount rate will be the weighted average cost of capital as approved by the PUCN in NV Energy’s most recent General Rate Case, as applicable. Project LCOE and LCOS will not be compared to one another. BESS systems and renewable energy systems will be evaluated separately.

5.1.2 Non-Price Factor (up to 30%)

The primary purpose of the non-price analysis is to help gauge the factors related to the proposal which are outside of price. The non-price factor will be weighted up to 30% in the
determination of which proposals in this RFP will be chosen for each resource-specific initial shortlist. The scorecard will be used to score the non-price criteria under four categories: (1) Bidder’s (or its development team’s) project development experience; (2) technology and value attributes; (3) conformity to the terms of the pro forma agreement(s) and related exhibits; and (4) development milestones. The criteria for each of these four categories are set forth below.

Category 1 – Bidding Company/Development Team’s Project Development Experience

- Project Development Experience
- Nevada, Federal or Tribal Lands Development Experience
- Ownership/O&M Experience
- Safety – Occupational Safety and Health Administration recordable incident rate
- Financial Capability

Category 2 – Technology and Value Attributes

- Technical Feasibility
- Resource Quality
- Equipment Supply Control
- Utilization of Resource
- Flexibility
- Environmental Benefits
- Fuel Diversity/Hedging
- Other Ancillary Services

Category 3 – Conformity to Pro forma Agreement(s) and Related Exhibits

- Magnitude of proposed revisions to pro forma agreement(s)

Category 4 – Development Milestones

- Land and Environmental Authorization Status/Feasibility
- Water Rights
- Project Financing Status
- Interconnection Progress
- Transmission Requirements (Network Upgrades)
- Reasonableness of COD as Demonstrated by Critical Path Schedule
5.1.3 Economic Benefits Factor (up to 10%)

The economic benefits to the state of Nevada will take into consideration the following matters, based on information submitted by Bidders, and NV Energy’s evaluation:

- Location of jobs created
  - Within the soliciting NV Energy service territory
  - Within the non-soliciting NV Energy service territory
  - Within the state of Nevada
- Number of direct jobs created in Nevada
  - Jobs created during construction
  - Jobs created during operation
- Economic direct benefits to Nevada
  - The direct value of expenditures made in Nevada attributed to the Project
  - Other direct economic benefits to Nevada

Please note, if project is selected, the values provided for jobs and economic benefits will be included in the regulatory filing for approval of the agreement, which is available to the public.

5.2 Second Stage: Best and Final Pricing

Proposals selected for the shortlist in each product will have an opportunity to refresh their price to take into account further development of the project or updated pricing for equipment or other costs from the time the initial proposal was submitted to the time of “best and final” offer. However, Bidders are only permitted to lower their pricing during this refresh period. Bidders may not increase the pricing initially submitted with their proposal. Bidders are encouraged to lower their pricing or look for opportunities to enhance their production profiles (based, for example, on changes to equipment) and other means to increase the value of their proposals to NV Energy.

Bidders that advance to the initial shortlist are also required to submit, along with their best and final pricing:

- Completed Attachment I – NAC 704 Requirements;
- Proposed reactive capability curves (PPA Exhibit 22) and single line diagrams (PPA Exhibit 5) of the facility; and
A notice that Bidder has commenced discussions with the union(s) in accordance with Section 3.2.6.6 of this protocol.

5.2.1 The Final Shortlist

For each of the products, proposals on the initial shortlists will then be evaluated using a production cost model to determine the final shortlist based on the best and final pricing. NV Energy’s production cost simulation model, used for integrated resource planning, will be used to determine a list of proposals deemed as the final shortlist. BESS systems will be evaluated separately.

In its analysis for this RFP, the Company will run each of the resource-specific initial shortlisted proposals and portfolios through the Preferred Plan by replacing the equivalent amount of proposed MW of resources, for each of NPC and SPPC, in the Preferred Plan with each of the initial shortlisted proposals to determine the Present Worth Revenue Requirement (“PWRR”) of each alternative portfolio of resources.

NV Energy may choose to engage the final shortlist Bidders in further discussions or negotiations. Any such discussions or negotiations may be terminated by NV Energy at any time, for any reason.

5.3 Final Selection of Proposal(s)

The two stages described above constitute the formal evaluation process which will be utilized to select the proposals that will be submitted to the PUCN for approval. In addition to this two-stage analysis, in selecting the final proposals, NV Energy will consider the non-price factors qualitatively. Furthermore, NV Energy will also include in its evaluation any factor that may impact the total cost of a resource, including, but not limited to, all of the factors used in the initial shortlist cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable.
6.0 AWARDING OF CONTRACTS

This RFP is merely an invitation to make proposals to the Company. No proposal in and of itself constitutes a binding contract. The Company may, in its sole discretion, perform any one or more of the following:

- Determine which proposals are eligible for consideration as proposals in response to this RFP.
- Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each Bidder.
- Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
- Negotiate and request Bidders to amend any proposals.
- Select and enter into agreements with the Bidder(s) who, in the Company’s sole judgment, is most responsive to this RFP and whose proposals best satisfy the interests of the Company, its customers, and state legal and regulatory requirements, and not necessarily on the basis of any single factor alone.
- Issue additional subsequent solicitations for proposals.
- Reject any or all proposals in whole or in part.
- Vary any timetable.
- Conduct any briefing session or further RFP process on any terms and conditions.
- Withdraw any invitation to submit a response.
- Select and enter into agreements with Bidder(s) for additional MW of renewable energy resources should additional demand be identified.

7.0 POST-BID NEGOTIATIONS

NV Energy may further negotiate both price and contract terms and conditions during post-bid negotiations. Post-bid negotiation will be based on NV Energy’s cost and value assessment. NV Energy will continually update its economic and risk evaluations until both parties execute a definitive agreement acceptable to NV Energy in its sole discretion. All transactions are subject to the approval of the PUCN on terms and conditions that are satisfactory to NV Energy in its sole and absolute discretion.
ATTACHMENT A – CONFIDENTIALITY AGREEMENT

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT B – VOLUNTARY CONSENT FORM

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT C – PRO FORMA POWER PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT D – PRO FORMA ASSET PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT E – PRO FORMA BUILD TRANSFER AGREEMENT AND EXHIBITS

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT F – PRO FORMA O&M TERM SHEET

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT G – PROPOSAL INPUT FORMS

(Price, Non-Price and Economic Benefit Input Forms)

This attachment is available in electronic format in PowerAdvocate. The contents of the workbook are as follows:

1) TOC (Table of Contents)
2) Scoring Structure
3) Evaluation Components
4) Corporate Information *
5) Price Input *
6) 8760 Prod. Profile *
7) Price Input –BESS *
8) Non-Price Scoring
9) Non-Price Input *
10) Economic Benefit Scoring
11) Econ Benefit Input *
   a. SolarPV *
   b. Energy Storage *
   c. Wind *
   d. Geothermal *
   e. Biopower *
   f. Hydro *
   g. Fossil *
12) Technology Specific Data
   a. Solar Data *
   b. Energy Storage Data *
   c. Wind Data *
   d. Geo Data *
   e. Biopower Data *
   f. Hydro Data *
   g. Fossil Data *

* Worksheet required to be completed by Bidder, as applicable to proposed product
ATTACHMENT H – BIDDER PROPOSAL COMPLIANCE CHECKLIST

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT I – NEVADA ADMINISTRATIVE CODE 704 REQUIREMENTS

This attachment is available in electronic format in PowerAdvocate.

Bidders that advance to the initial shortlist are required to submit Attachment I along with their best and final pricing.
ATTACHMENT J – BIDDER’S SAFETY PLAN

(Outline of NV Energy’s Safety Plan, as Example)

This attachment is available in electronic format in PowerAdvocate.
ATTACHMENT K – APPROVED VENDORS LIST

This attachment is available in electronic format in PowerAdvocate.

The Approved Vendors List shall be included as an exhibit to any agreement executed by the parties.

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20 This list is not intended to be an endorsement of the vendors listed or to be all-inclusive. It simply acknowledges the vendors that NV Energy has approved of as of the date of this document, and is subject to change.
ATTACHMENT L – DISPATCHABLE AND FULL REQUIREMENTS PERIODS

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**Dispatchable Period**

**Full Requirements Period**
ATTACHMENT M – ROLE OF INDEPENDENT EVALUATOR

In order to provide for a transparent and fair process, the Fall 2018 RE RFP will be conducted under the oversight of an Independent Evaluator (“IE”).

• The IE will monitor and oversee the RFP to ensure that a competitive, fair and transparent RFP process is conducted, including the following:
  • Communications between bidder and the Company;
  • Any requested bidder updates to proposals
  • Any amendments to the renewable RFP issued by the Company
  • Evaluation and ranking of bid responses;
  • Selection of the initial shortlist of bids;
  • Selection of the final shortlist of bids; and
  • Negotiation of proposed contract(s) with successful Bidders.

• Validate that the renewable RFP evaluation criteria, methods, models, and other processes have been consistently and appropriately applied to all bids. Verify that the assumptions, inputs, outputs and results are appropriate and reasonable.

• Verify the basis for selection of the initial shortlist of bids:
  • Verify that the price score is based on the LCOE, LCOS or financial model, as applicable, and is consistently applied to all bids.
  • Verify that the non-price score is based on the evaluation criteria specified in the RFP (i.e., project development experience, project technology, value attributes, conformity to pro forma, development milestones, economic benefits, etc.).

• Verify the basis for selection of the final shortlist of bids:
  • Verify the results of the production cost simulation modeling of candidate resources on overall system costs and risks, and
  • Verify that the Company fairly and consistently applies any qualitative evaluation of the non-price factors, including but not limited to any factor that may impact the total cost of a resource, consideration of accounting treatment and potential effects due to rating agency treatment.

• The IE will independently score bids to determine whether the Company’s initial or final selections are reasonable.

• The IE and the Company will compare scores of selected bids and attempt to reconcile and resolve any scoring differences.

• The IE will monitor negotiations between the Company and the selected bidder(s).

• The IE will complete and submit a report that will detail bid scoring and evaluation results with a detailed assessment of the Company’s selection of the winning proposal(s).
ATTACHMENT N – FORM OF WORK SITE AGREEMENT

This attachment is available in electronic format in PowerAdvocate.

The form of WSA, as modified, or an executed WSA, is to be inserted in the applicable exhibit of the agreement being proposed, unless the proposal is for Product 2A (as set forth in Table 1).
ATTACHMENT O – METERING SCHEME EXAMPLES

Battery Storage: NV Energy requires that all battery storage facilities have a dedicated bi-directional meter. For generation and storage facilities, the storage meter will be installed on the low-side common AC bus-side of the inverter(s). This meter will be used to track the energy used to charge the battery as well as energy discharged from the battery. Facilities utilizing only battery storage on a dedicated lead line will install a single high-side meter.

In addition to the required bi-directional battery storage meter, NV Energy requires all generation facilities to have a high-side aggregate meter. This meter must be located on the high-side of the generator step-up transformer and will measure the total output of the interconnected facility.

With the addition of multiple complex generation facilities, NV Energy proposes the use of the following metering schemes for generation/storage facilities.

Scheme 1:

The configuration in Figure 1 shows a generation facility with two PV feeders and a battery storage feeder. The battery storage feeder is required to have an AC, low-side meter compensated to the point of interconnection (POI). The two PV feeders are under the same PPA and selling to the same company. A high-side meter accounts for the output of all three facilities. Since the PV feeders are under the same PPA, no additional meters are required.

*Figure 1: Solar and Storage with Single GSU and Common PPA*
Scheme 2:

The configuration in Figure 2 is similar to Figure 1, except the solar feeders have different PPA’s. In addition to the AC coupled battery storage meter, each solar feeder is required to have an individual meter. This allows each PPA to be metered while adhering to CAISO EIM requirements. NV Energy is currently working on an advanced metering system to dynamically allocate losses between all generation feeders. This will allow the low-side meters to accurately allocate line and transformer losses based on PV/storage production.

*Figure 2: Solar and Storage with Single GSU and Multiple PPA’s*

Scheme 3:

The configuration proposed in Figure 3 is for multiple GSU’s and PPA’s. This configuration is similar to Figure 2, except the addition of another GSU requires the inclusion of a common low-side meter. Each storage facility will continue to be required to have an AC meter. Each solar facility will be required to have a low-side meter measuring the gross output of the feeder. An additional common low-side meter is required to accurately allocate transformer and line losses using dynamic loss compensation.
Scheme 4:

The configuration proposed in Figure 4 is for a single storage facility on a dedicated lead line. This configuration requires a high-side meter compensated to the POI. If multiple feeders of battery storage are added, each with separate PPA’s, Scheme 2 will be required.
ATTACHMENT P – PROPOSAL ZIP FILE STRUCTURE

This attachment is available in electronic format in PowerAdvocate.
FALL 2018
RENEWABLE ENERGY
REQUEST FOR PROPOSALS
SCHEDULE UPDATE

Original Issued: October 16, 2018
Schedule Update: December 6, 2018
Bid Event Website: www.poweradvocate.com
Due to the variety and complexity of the products being solicited and NV Energy’s more recent request for both PPA and BTA proposals, there has been a high volume of questions posed by bidders. Recognizing that additional time would be valuable for bidders to incorporate those responses and prepare their proposals, NV Energy has extended the bid due date by one week to December 17, 2018 at 4:00 pm (PPT). Accordingly, the bidder questions deadline is extended to December 12, 2018 at 1:00 pm (PPT) and bid fees must be postmarked by December 19, 2018.

**Table 2 – RFP Schedule Update**

<table>
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<th>Original Target Schedule</th>
<th>Revised Target Schedule</th>
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<td>Launch RFP</td>
<td>October 16, 2018</td>
<td>October 16, 2018</td>
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<td>Pre-Bid Conference and Webinar</td>
<td>October 30, 2018</td>
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<td>Bidder Questions Deadline (1pm)</td>
<td>December 5, 2018</td>
<td>December 12, 2018</td>
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<td>Bids Due (4pm)</td>
<td>December 10, 2018</td>
<td>December 17, 2018</td>
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<tr>
<td>Bid Fees Postmark Deadline</td>
<td>December 12, 2018</td>
<td>December 19, 2018</td>
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<td>SIS Due to NVE</td>
<td>January 14, 2019</td>
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<td>Initial Shortlist Issued</td>
<td>January 21, 2019</td>
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<td>Best and Final Pricing Due:</td>
<td>January 25, 2019</td>
<td>February 8, 2019</td>
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<td>February 11, 2019</td>
<td>February 18, 2019</td>
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<td>Contract Negotiations Conclude</td>
<td>March 18, 2019</td>
<td>March 22, 2019</td>
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<td>Execution of Contract(s)</td>
<td>March 21, 2019</td>
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<td>PUCN Filing for Approval</td>
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<td>Commercial Operation Achieved On or Before</td>
<td>December 31, 2023</td>
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REN-6-GS (a)
POWER PURCHASE AGREEMENT
FOR RENEWABLE-DISPATCHABLE GENERATING FACILITY

BETWEEN

NEVADA POWER COMPANY D/B/A NV ENERGY

AND

SOLAR PARTNERS XI, LLC

Gemini Solar
Clark County, Nevada
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POWER PURCHASE AGREEMENT FOR A RENEWABLE-DISPATCHABLE GENERATING FACILITY

This Power Purchase Agreement for a Renewable-Dispatchable Generating Facility (this “Agreement”) is made and entered into as of May 1, 2019 (the “Effective Date”) by and between NEVADA POWER COMPANY, a Nevada corporation, d/b/a NV Energy acting in its merchant function capacity (“Buyer”), and SOLAR PARTNERS XI, LLC, a Delaware limited liability company (“Supplier”). Buyer and Supplier are sometimes referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, Buyer is an operating electric public utility, subject to the applicable rules and regulations of the PUCN and FERC (as such terms are defined below);

WHEREAS, Buyer seeks the ability to dispatch renewable energy at a fixed price in order to reduce its reliance on fossil fuels, to meet peak energy demand and obtain Ancillary Services (as such term is defined below);

WHEREAS, Buyer intends to construct or cause to be constructed the Facility (as such term is defined below) upon the terms and conditions set forth herein; and

WHEREAS, Supplier desires to sell to Buyer, and Buyer desires to purchase from Supplier, Product (as such term is defined below) from the Facility upon the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the covenants and conditions contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Buyer and Supplier, intending to be legally bound, hereby agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the meanings set forth below:

1.1 “Accepted Compliance Costs” is defined in Section 3.5.

1.2 “Affiliate” means, with respect to any Person, each Person that directly or indirectly, controls or is controlled by or is under common control with such Person. For the purposes of this definition, “control” (including, with correlative meanings, the terms “controlled by” and “under common control with”), as used with respect to any Person, shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities or by contract or otherwise. Notwithstanding the foregoing, with respect to Buyer, unless Buyer assigns this Agreement or there is a change of control of Buyer, Affiliate shall only include Berkshire Hathaway Energy Company and its direct and indirect, wholly owned subsidiaries.
1.3 “AGC” or “Automatic Generation Control” means Supplier’s Automatic Generation Control for the Generating Facility which shall be compatible with Buyer’s Energy Management System.

1.4 “Agreement” means this Long-Term Renewable Power Purchase Agreement together with the Exhibits attached hereto, as amended from time to time.

1.5 “ALTA Survey” means a land survey prepared and certified in accordance with the standards jointly promulgated by the American Land Title Association and the American Congress on Surveying and Mapping.

1.6 “Ancillary Services” means those services necessary to support the transmission of electric power from Supplier to Buyer and to maintain reliable operations of the Transmission System, including but not limited to: voltage control, operating reserve, spinning reserve, and reactive power.

1.7 “Annual Charging-Only Energy Amount” means, with respect to each Contract Year, 115,000 MWh.

1.8 “ASC” is defined in Section 12.7.

1.9 “Availability Backcast Amount” means an amount determined by a backcasting analysis that takes into account both resource conditions and availability of the Generating Facility. The backcasting analysis will be performed by Supplier using a tool which will be mutually agreed upon by Buyer and Supplier in accordance with Exhibit 27 no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6. Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer. If the Parties disagree on the calculation of the Availability Backcast Amount, then the Availability Backcast Amount will be determined through the Dispute resolution provisions of Article 21.

1.10 “Availability Liquidated Damages” is defined in Exhibit 26.

1.11 “Availability Notice” means a notice delivered by Supplier to Buyer pursuant to Section 14.1 notifying Buyer of the availability of the Facility.

1.12 “Balancing Authority Area” is defined in the OATT (as may be modified from time to time) of the Balancing Authority Area Operator.

1.13 “Balancing Authority Area Operator” means a Person, and its agents and any successors thereto, that is responsible for the operation of the electric transmission system and for maintaining reliability of the electric transmission system, including the Transmission System, within the Balancing Authority Area where the Facility is located. As of the Effective Date, the Balancing Authority Area Operator is the Transmission Provider.

1.14 “Billing Period” is defined in Section 7.2.1.
1.15 “Business Day” means any day other than Saturday, Sunday and any day that is a holiday observed by Buyer.

1.16 “Buyer” is defined in the preamble of this Agreement and includes such Person’s permitted successors and assigns.

1.17 “Buyer ROFO Notice” is defined in Section 6.1.1.

1.18 “Buyer’s Charging Energy” means all Energy produced by the Generating Facility, net of transformation and transmission losses, if any, measured at the Storage Facility Metering Points that is a result of a Charging Notice given by Buyer. All Buyer’s Charging Energy shall be used for Buyer’s benefit in accordance with Charging Notices and Discharging Notices given by Buyer. Buyer’s payment for Buyer’s Charging Energy shall not be for more than the amount of Energy flowing through, and delivered at, the Storage Facility Metering Points and, in any event, not greater than the amount of Buyer’s Charging Energy included in the applicable Charging Notice.

1.19 “Buyer’s PC Account” means the account maintained by the PC Administrator for the purpose of tracking the production, sale, transfer, purchase and retirement of PCs by Buyer, or such other account, including a WREGIS account, as Buyer may designate from time to time.

1.20 “Buyer’s Required Regulatory Approvals” means the approvals, consents, authorizations or permits of, or filing with, or notification to the Governmental Authorities listed on Exhibit 9, and such others as are deemed by Buyer to be necessary or desirable from time to time.

1.21 “CAMD” means the Clean Air Markets Division of the Environmental Protection Agency or successor administrator, or any state or federal Governmental Authority given jurisdiction over a program involving transferability of Renewable Energy Benefits or any part thereof.

1.22 “Capacity Rights” means any current or future defined characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, including any of the same counted towards any current or future resource adequacy or reserve requirements, associated with the electric generation capability and capacity of the Facility or the Facility’s capability and ability to produce energy. Capacity Rights are measured in MW and do not include any Tax incentives of any kind existing now or in the future associated with the construction, ownership or operation of the Facility.

1.23 “Certified Nameplate Capacity Rating” is defined in Section 8.3.2.2.

1.24 “Charging Energy” means Buyer’s Charging Energy and Supplier’s Charging Energy.
1.25 "Charging Notice" means the operating instruction, and any subsequent updates, given by Buyer to Supplier, directing delivery of Buyer’s Charging Energy to the Storage Facility to charge it at a specific MW rate to a specified Stored Energy Level, provided that any operating instruction shall be in accordance with the Storage Operating Procedures. Charging Notices may be communicated electronically, via facsimile, telephonically or other verbal means, provided that telephonic or other verbal communications shall be documented (either recorded by tape, electronically or in writing), and such recordings shall be made available to both Buyer and Supplier upon request for settlement purposes. For the avoidance of doubt, any Buyer request to initiate a Storage Capacity Test shall not be considered a Charging Notice.

1.26 "Charging-Only Energy" means, for any Delivery Hour during the Dispatch Availability Months, Energy that the Generating Facility is capable of generating in such Delivery Hour that is in excess of the Delivery Points Maximum Amount.

1.27 "Commercial Operation" means that: (a) the Generating Facility is fully operational, reliable and interconnected, fully integrated and synchronized with the Transmission System, and that the Storage Facility is fully capable of charging, storing and discharging energy up to the Storage Contract Capacity; (b) Supplier shall have received or obtained all Required Facility Documents; and (c) which occurs when all of the requirements set forth in Sections 8.1, 8.3 and 17.2 and Exhibits 6 and 7 (i) have occurred, and (ii) remain simultaneously true and accurate: (A) as of the date and time Supplier gives Buyer notice that Commercial Operation has occurred; and (B) for the period Buyer has to review Supplier’s notice of Commercial Operation pursuant to Section 8.2.1.

1.28 "Commercial Operation Date" means the date on which Commercial Operation occurs.

1.29 "Commercial Operation Deadline" means the date specified in Exhibit 6 by which the Commercial Operation Date must occur, as such date may be extended if and to the extent Supplier fails to achieve the Commercial Operation Date as a result of Force Majeure.

1.30 "Compliance Cost Cap" is defined in Section 3.5.

1.31 "Construction Contract" means one or more construction and equipment supply agreements, in each case, between a Construction Contractor and Supplier (or one of its Affiliates), pursuant to which, in the aggregate, the Facility will be designed, engineered, constructed, tested and commissioned.

1.32 "Construction Contractor" with respect to a Construction Contract, means the construction contractor and/or equipment supplier that is party to such Construction Contract.

1.33 "Contract Representative" of a Party, means the individual designated by that Party in Exhibit 4 as responsible for ensuring effective communication, coordination and
cooperation between the Parties. A Party may change its Contract Representative by providing notice of such change to the other Party in accordance with the procedures set forth in Section 29.1.

1.34 “Contract Year” means each year during the Term beginning on January 1 and ending on December 31 of the year following the Commercial Operation Date (or commencing on the Commercial Operation Date if the Commercial Operation Date is January 1).

1.35 “Controlling Interest” with respect to a Person, means more than fifty percent (50%) of the outstanding ownership interest of such Person, or the power to vote such percentage of ownership interest.

1.36 “Credit Rating” of a Person means the credit rating then assigned by a Relevant Rating Agency to the long-term, senior, unsecured, non-credit-enhanced indebtedness of that Person.

1.37 “Critical Project Milestone” means a Project Milestone designated as a Critical Project Milestone on Exhibit 6.

1.38 “Cure Period” is defined in Section 24.3.

1.39 “Curtailed Product” is defined in Section 10.1.1.

1.40 “Daily Delay Damages” means an amount equal to: (a) with respect to the first (1st) through and including the sixtieth (60th) day subsequent to the Commercial Operation Deadline, three hundred one dollars and fifty three cents ($301.53) per MW of Expected Nameplate Capacity Rating per day; (b) with respect to the sixty-first (61st) through and including the one-hundred-twentieth (120th) day subsequent to the Commercial Operation Deadline, six hundred three dollars and six cents ($603.06) per MW of Expected Nameplate Capacity Rating per day; and (c) with respect to the one-hundred-twenty-first (121st) through and including the one hundred and eightieth (180th) day subsequent to the Commercial Operation Deadline, nine hundred four dollars and fifty nine cents ($904.59) per MW of Expected Nameplate Capacity Rating per day.

1.41 “Defaulting Party” is defined in Section 24.1.

1.42 “Deficit Damages” is defined in Section 8.6.1.

1.43 “Deficit Damages Rate” means two hundred thousand dollars ($200,000) per MW.

1.44 “Delivered Amount” means, with respect to any Delivery Hour or period, the actual amount of Net Energy delivered by Supplier and accepted by Buyer at the Delivery Points during such Delivery Hour or period, and, if applicable, Buyer’s Charging Energy delivered by Supplier to the Storage Facility Metering Points during such Delivery Hour or period.
1.45 “Delivered PCs” means PCs that have been delivered by Supplier and awarded to Buyer pursuant to the terms of this Agreement, in accordance with the Portfolio Standard and which have been properly delivered and recorded to Buyer’s PC Account.

1.46 “Delivery Hour” means each hour.

1.47 “Delivery Points” means, with respect to Net Energy (other than Buyer’s Charging Energy) and Discharging Energy, the delivery points on the Transmission System set forth in Exhibit 5.

1.48 “Delivery Points Maximum Amount” means, with respect to a Delivery Hour, the amount defined in Section 5(b)(iv) of Exhibit 1 (in MW) multiplied by one (1) hour.

1.49 “Derating” means a condition of the Generating Facility as a result of which the actual available generating capacity of the Generating Facility is less than the Certified Nameplate Capacity Rating.

1.50 “Development Security” is defined in Section 17.1.

1.51 “Deviation Amount” is defined in Section 3.6.2.1.

1.52 “Discharging Energy” means all Energy discharged by the Storage Facility, less inverter, transformation and transmission losses, if any, and delivered to the Delivery Points.

1.53 “Discharging Notice” means the operating instruction, and any subsequent updates, given by Buyer to Supplier, directing the Storage Facility to discharge Discharging Energy at a specific MW rate to a specified Stored Energy Level, provided that any operating instruction shall be in accordance with the Storage Operating Procedures. Discharging Notices may be communicated electronically, via facsimile, telephonically or other verbal means, provided that telephonic or other verbal communications shall be documented (either recorded by tape, electronically or in writing), and such recordings shall be made available to both Buyer and Supplier upon request for settlement purposes.

1.54 “Dispatch Availability Amount” means, with respect to any Delivery Hour, the amount of Energy stated in Exhibit 13A for such Delivery Hour.

1.55 “Dispatch Availability Month” is defined in Section 3.4.10.1.

1.56 “Dispatch Availability Shortfall” is defined in Section 3.6.1.1.

1.57 “Dispatch Availability Shortfall Amount” is defined in Section 3.6.1.1.

1.58 “Dispatchable Accuracy Rate” or “DAR” means a measure of the ability of the Generating Facility (and the AGC, as applicable) to follow Buyer’s Energy Management System signals as calculated pursuant to Exhibit 16.
1.59 “Dispatchable Accuracy Rate Threshold” or “DAR Threshold” is defined in Section 3.6.2.1.

1.60 “Dispatchable Period” the period in the Stub Period or a Contract Year, as applicable, outside of the Full Requirements Period, consisting of January through May, and September through December, for all hours, and for the months of June through August, hour ending 0100 through 1600, and hour ending 2200 through 2400 as identified in Exhibit 13B.

1.61 “Dispatchable Period Product Rate” means the Product Rate identified in Exhibit 2A as the Dispatchable Period Product Rate.

1.62 “Dispatchable Period Replacement Costs” is defined in Section 3.6.1.2.

1.63 “Dispatched Amount” is defined in Section 3.4.7.

1.64 “Dispute” is defined in Section 21.1.

1.65 “Early Purchase Option” is defined in Section 6.2.1.

1.66 “Effective Date” is defined in the preamble of this Agreement.

1.67 “Electric System Authority” means each of NERC, WECC, WREGIS, Balancing Authority Area Operator, Market Operator, a Regional Transmission Organization, a regional or sub-regional reliability council or authority, and any other similar council, corporation, organization or body of recognized standing with respect to the operations of the electric system in the WECC region.

1.68 “Emergency” means any circumstance or combination of circumstances or any condition of the Facility, the Transmission System or the transmission system of other transmission operators, which is determined or reported by Supplier, the Transmission Provider or any Electric System Authority, whether planned or unplanned, to be: (a) reasonably likely to endanger life or property and necessitates immediate action to avert injury to persons or serious damage to property or (b) reasonably likely to adversely affect, degrade or impair Transmission System reliability or transmission system reliability of the transmission system of other electric utilities.

1.69 “EMS” or “Energy Management System” means Buyer’s equipment and software used to monitor, control and optimize the performance of Buyer’s generating system.

1.70 “Energy” means all energy that is generated by the Generating Facility.

1.71 “Energy Imbalance Market” means generation facilities electrically located within the Balancing Authority Area that are, from time to time, bid into or otherwise subject to dispatch instructions issued or originating from the Market Operator.
1.72 “Environmental Contamination” means the introduction or presence of Hazardous Substances at such levels, quantities or location, or of such form or character, as to constitute a violation of Laws and present a material risk under Laws that the Project Site will not be available or usable for the purposes contemplated by this Agreement.

1.73 “Environmental Law” shall mean any Law relating to the protection, preservation or restoration of human health, the environment, or natural resources, including any Law relating to the releases or threatened releases of Hazardous Substances into any medium (including ambient air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, release, transport and handling of Hazardous Substances.

1.74 “Event of Default” is defined in Section 24.1.

1.75 “EWG” means an “exempt wholesale generator” as defined in the Public Utility Holding Company Act of 2005 and in implementing regulations issued thereunder.

1.76 “Excess Charging Energy” is defined in Section 3.4.8.3.

1.77 “Excess Energy” means for the Dispatchable Period, (a) with respect to the Stub Period, the portion of the Delivered Amount plus any Un-Dispatched Amount for the Stub Period, if any, that exceeds one hundred percent (100%) of the Maximum Amount for the Stub Period, and (b) with respect to a Contract Year, the portion of the Delivered Amount plus any Un-Dispatched Amount for such Contract Year, if any, that exceeds one hundred percent (100%) of the Maximum Amount for such Contract Year; provided, however, that Delivered Amount plus Un-Dispatched Amount in excess of the Delivery Points Maximum Amount for any Delivery Hour shall be excluded for purposes of determining Excess Energy.

1.78 “Excused Product” is defined in Section 3.6.6.

1.79 “Expected Nameplate Capacity Rating” is defined in Exhibit 1.

1.80 “Facility” means the Generating Facility and the Storage Facility.

1.81 “Fair Market Value” means the price which a willing buyer would pay for the Facility in an arm’s-length transaction to a willing seller under no compulsion to sell, as such price shall be determined by mutual agreement of the Parties or, absent mutual agreement of the Parties, pursuant to Section 6.6.

1.82 “FERC” means the Federal Energy Regulatory Commission and any successor.

1.83 “Final Purchase Option” is defined in Section 6.3.

1.84 “FRP Deemed Delivered Energy” is defined in Section 14.3.2.
1.85 “Full Requirements Capacity Shortfall” is defined in Section 3.6.4.1.

1.86 “Full Requirements Capacity Shortfall Amount” is defined in Section 3.6.4.1.

1.87 “Full Requirements Period” means hours ending 1700-2100 for the months of June, July and August, as identified in Exhibit 13B, in the Stub Period or a Contract Year, as applicable.

1.88 “Full Requirements Period Capacity Factor” means the percentage stated in Exhibit 1, Section 5(b)(v).

1.89 “Full Requirements Period Charging Energy” means all Energy produced by the Generating Facility, less transformation and transmission losses, if any, delivered to the Storage Facility Metering Points during the months of June, July or August.

1.90 “Full Requirements Period Product” is the amount of Product, as measured by Net Energy, required to be delivered during the Full Requirements Period, which is equal to the product of (a) the Full Requirements Period Capacity Factor, times (b) the Certified Nameplate Capacity Rating, times (c) four hundred sixty (460) hours.

1.91 “Full Requirements Period Product Rate” means the Product Rate identified in Exhibit 2A as the Full Requirements Period Product Rate.

1.92 “Full Requirements Period Replacement Costs” is defined in Section 3.6.4.1.

1.93 “Force Majeure” is defined in Section 20.2.

1.94 “Generating Facility” means Supplier’s generating power plant as described in Exhibit 1, located at the Project Site as identified in Exhibit 3A and 3B and including mechanical equipment and associated facilities and equipment required to deliver Net Energy to the Delivery Points and Storage Facility Metering Points, including items as further described in Exhibits 1, 3A, 3B, 5 and 14, and as such generating power plant may be modified from time to time in accordance with the terms hereof.

1.95 “Good Utility Practice” means (a) the applicable practices, methods and acts required by or consistent with applicable Laws and reliability criteria, whether or not the Party whose conduct at issue is a member of any relevant organization and otherwise engaged in or approved by a significant portion of the electric utility industry during the relevant time period with respect to grid-interconnected, utility-scale generating facilities with integrated storage in the Western United States, or (b) any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to acceptable practices, methods or acts generally accepted.
in the industry with respect to grid-interconnected, utility-scale generating facilities with integrated storage in the Western United States. Good Utility Practice shall include compliance with applicable Laws, applicable reliability criteria, and the criteria, rules and standards promulgated in the National Electric Safety Code and the National Electrical Code, as they may be amended or superseded from time to time, including the criteria, rules and standards of any successor organizations.

1.96 “Governmental Approval” means any authorization, approval, consent, license, ruling, permit, tariff, certification, exemption, order, recognition, grant, confirmation, clearance, filing, notification, or registration of, by, with or to any Governmental Authority.

1.97 “Governmental Authority” means, as to any Person, any federal, state, local, or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over such Person or its property or operations, and with respect to Supplier, specifically includes FERC, the PUCN, NERC, WECC and WREGIS.

1.98 “Guaranteed Storage Availability” is defined in Section 3.4.10.1.

1.99 “Guarantee” means a Guarantee substantially in the form of Exhibit 20.

1.100 “Hazardous Substance” means: (a) any petroleum or petroleum products, flammable materials, explosives, radioactive materials, friable asbestos, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls (PCBs) in regulated concentrations; (b) any chemicals or other materials or substances which are now or hereafter become defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “extremely hazardous wastes,” “restricted hazardous wastes,” “toxic substances,” “toxic pollutants,” “contaminants,” “pollutants” or words of similar import under any Environmental Law; and (c) any other chemical or other material or substance, exposure to which is now or hereafter prohibited, limited or regulated as such under any Environmental Law, including the Resource Conservation and Recovery Act, 42 U.S.C. section 6901 et seq., the Comprehensive Environmental Response Compensation and Liability Act, 42 U.S.C. section 9601 et seq., or any similar state statute.

1.101 “IA” means (a) the Large Generator Interconnection Agreement executed on June 11, 2018, as amended from time to time, between Supplier and the Transmission Provider for the portion of the Facility interconnected at 230 kV (“230 kV IA”), and (b) the Large Generator Interconnection Agreement, as amended from time to time, between Supplier and the Transmission Provider for the portion of the Facility interconnected at 525 kV. This definition may be revised in accordance with Section 8.2.3.
1.102  "IEEE-SA" means the Institute of Electrical and Electronics Engineers Standards Association and any successor entity thereto.

1.103  "Indemnified Party" is defined in Section 18.1.

1.104  "Indemnifying Party" is defined in Section 18.1.

1.105  "Intraday Schedule Change" is defined in Section 14.2.2.

1.106  "Invoice" means the statements described in Section 7.2 setting forth the information required therein, as well as the associated payment due for the Billing Period, the Measurement Period or the Contract Year, as the case may be, in accordance with Exhibits 2B and 2C.

1.107  "ITC" means the investment tax credit established pursuant to Section 48 of the United States Internal Revenue Code of 1986.

1.108  "Law" means any federal, state, local or other law (including any Environmental Laws), common law, treaty, code, rule, ordinance, binding directive, regulation, order, judgment, decree, ruling, determination, permit, certificate, authorization, or approval of a Governmental Authority which is binding on a Party or any of its property.

1.109  "Loss" with respect to a Person means, any and all claims, demands, suits, obligations, payments, liabilities, costs, fines, Regulatory Penalties, sanctions, Taxes, judgments, damages, losses or expenses imposed by a third party upon such Person or incurred in connection with a claim by a third party against such Person.

1.110  "Licensed Professional Engineer" means a person proposed by Supplier and acceptable to Buyer in its reasonable judgment who: (a) is licensed to practice engineering in the appropriate engineering discipline for the required certification being made in Nevada; (b) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion; (c) has no economic relationship, association, or nexus with Supplier and is not an employee of its members or Affiliates, other than with the prior written consent of Buyer, for services previously or currently being rendered to Supplier or its members or Affiliates; and (d) is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility.

1.111  "Market Operator" means, if applicable, the California Independent System Operator Corporation or any other entity performing the market operator function for the Energy Imbalance Market.

1.112  "Market Price" means the simple average of MEAD for the Dispatchable Period or the Full Requirements Period, as applicable.
1.113 "Material Adverse Effect" means, with respect to a Party, a material adverse effect on: (a) the ability of such Party to perform its obligations under this Agreement, individually or in the aggregate; (b) the validity or enforceability of this Agreement or the transaction contemplated hereby; or (c) on the business, assets, operations, property or condition (financial or otherwise) of such Party.

1.114 "Maximum Amount" means (a) for the Stub Period, 100% of the Dispatch Availability Amounts (in MWh) for all hours in the Stub Period, plus the pro-rated portion of the Annual Charging-Only Energy Amount, and (b) for any Contract Year, 100% of the Dispatch Availability Amounts (in MWh) for all hours in such Contract Year, plus the Annual Charging-Only Energy Amount.

1.115 "Mead" means the Hourly Mead Index published by Powerdex.

1.116 "Measurement Period" means each one (1) Contract Year commencing with the first one (1) Contract Year of the Term.

1.117 "Meter" means any of the physical or electronic metering devices, data processing equipment and apparatus associated with the meters required for: (a) accurate determination of the: quantities of Delivered Amounts from the Facility, the quantities of Charging Energy delivered to the Storage Facility Metering Points, the amount of Discharging Energy delivered to the Delivery Points, and for recording other related parameters required for the reporting of data to Supplier: (b) the computation of the payments due from one Party to another under this Agreement; and (c) compliance with requirements of any Electric System Authority, any Governmental Authority or Transmission Provider. Meters do not include any check meters Supplier may elect to install as contemplated by Section 7.1.1.

1.118 "Minimum Credit Rating" of a Person means that the Credit Rating of that Person is at least (a) BBB- (or its equivalent) as determined by Standard & Poor’s and (b) Baa3 (or its equivalent) as determined by Moody’s.

1.119 "Monthly Storage Availability" is defined in Exhibit 26.

1.120 "Moody’s" means Moody’s Investor Services, Inc. and any successor.

1.121 "MW" means megawatts of electrical power in AC.

1.122 "MWh" and "MWhs" mean a megawatt hour or megawatt hours of electrical energy.

1.123 "NAC" means the Nevada Administrative Code.

1.124 "NERC" means the North American Electric Reliability Corporation and any successor.
1.125 “Net Energy” means: (a) during the Dispatchable Period, all Energy produced by the Generating Facility (including Buyer’s Charging Energy, but not Full Requirements Period Charging Energy or Discharging Energy), all of which shall be net of Station Usage, and transformation and transmission losses and other adjustments (e.g., Supplier’s load other than Station Usage), if any, and delivered to Buyer at the Delivery Points or the Storage Facility Metering Points, and (b) during the Full Requirements Period, all Energy produced by the Generating Facility and all Discharging Energy delivered to and received by Buyer at the Delivery Points.

1.126 “Network Resource” is defined in the OATT.

1.127 “Non-Defaulting Party” means the Party other than the Defaulting Party.

1.128 “Notice” is defined in Section 29.1.1.

1.129 “Notice to Proceed” means the initial notification by Supplier to its Construction Contractor to commence work under the Construction Contract.

1.130 “NRS” means the Nevada Revised Statutes.

1.131 “OATT” means Transmission Provider’s or the Balancing Authority Area Operator’s then-effective Open Access Transmission Tariff, which has been accepted for filing by FERC.

1.132 “Offered Interests” is defined in Section 6.1.1.

1.133 “Operating Representative” of a Party means any of the individuals designated by that Party, as set forth in Exhibit 4, to transmit and receive routine operating and Emergency communications required under this Agreement. A Party may change any of its Operating Representatives by providing notice of the change to the other Party in accordance with the notice procedures set forth in Section 29.1.

1.134 “Operating Security” is defined in Section 17.2.

1.135 “Operation Date” means the first date on which the Generating Facility is energized and operates in parallel with the Transmission System and delivers Net Energy to and at the Delivery Points and Storage Facility Metering Points and the Storage Facility is capable of charging, storing and discharging energy in amounts less than or up to the Storage Contract Capacity and receiving instructions to charge, store and discharge energy.

1.136 “Over Delivery Amount” is defined in Section 3.6.3.1.

1.137 “PPT” means Pacific Standard Time or Pacific Daylight Time, whichever is then prevailing in Las Vegas, Nevada.
1.138 “Party” or “Parties” means each entity set forth in the preamble of this Agreement and its permitted successor or assigns.

1.139 “PC” or “Portfolio Energy Credit” means a unit of credit which equals one kilowatt-hour of electricity generated, acquired or saved (or deemed so) by the Facility, all as calculated by the PUCN operations staff and certified by the PC Administrator pursuant to the Renewable Energy Law (or by a successor Governmental Authority pursuant to a successor Law if the Renewable Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada), and certified by WREGIS.

1.140 “PC Administrator” means the Person appointed by the PUCN to administer the system of Portfolio Energy Credits established pursuant to the Portfolio Standard or a successor Governmental Authority pursuant to a successor Law if the Renewable Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada.

1.141 “PC Replacement Costs” is defined in Section 3.7.1.

1.142 “PC Shortfall” is defined in Section 3.7.1.

1.143 “PC Shortfall Amount” is defined in Section 3.7.1.

1.144 PC Shortfall Threshold” is defined in Section 3.7.1.

1.145 “Permitted Transfer” means any of the following: (a) any foreclosure by Supplier’s Lenders pursuant to any financing, including tax equity financing, or other financial arrangements for the Facility; (b) any change of economic and voting rights triggered in Supplier’s organizational documents arising from the financing of the Facility and which does not result in the transfer of ownership, economic or voting rights to any entity that had no such rights immediately prior to the change; or (c) the direct or indirect transfer of shares of, or equity interests in, Supplier to Supplier’s Lenders as part of a tax equity financing.

1.146 “Person” or “Persons” means any natural person, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or Governmental Authority.

1.147 “Planned Outage” is defined in Article 11.1.

1.148 “Portfolio Standard” means the amount of electricity that Buyer must generate, acquire, or save from renewable energy systems or efficiency measures specified by the percentage of the total amount of electricity sold by Buyer to its retail customers in the State of Nevada pursuant to the Renewable Energy Law, as established pursuant to NRS 704.7821, and the regulations, guidance and requirements promulgated thereunder, as may be amended, preempted or superseded from time to time (or pursuant to a successor Law if the Renewable
Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada).

1.149 “Power Quality Standards” means the power quality standards established by NERC, WECC, Buyer, IEEE-SA, National Electric Safety Code, the National Electric Code, or their respective successor organizations or codes, as they may be amended or superseded from time to time, and consistent with Good Utility Practice.

1.150 “Product” means all (a) Net Energy, (b) PCs (and any equivalent rights in any other jurisdiction), (c) Renewable Energy Benefits, (d) Capacity Rights, and (e) Ancillary Services in each case, arising from or relating to the Facility, including Storage Product.

1.151 “Product Rate” means, for any period, the applicable rate set forth in Exhibit 2A for such period.

1.152 “Project Milestone” means each of the milestones listed in Exhibit 6.

1.153 “Project Site” means the site for the Facility, as more particularly described in Exhibit 3A and depicted in Exhibit 3B.

1.154 “Provisional Energy” means Net Energy (but not Test Energy) that is delivered by Supplier to Buyer prior to the Commercial Operation Date and at the request of Buyer in increments of no less than five (5) MW up to an aggregate maximum of six hundred ninety (690) MW.

1.155 “Provisional Product Rate” is defined in Section 4.1.1.2.

1.156 “PUCN” means the Public Utilities Commission of Nevada and any successor.

1.157 “PUCN Approval” is defined in Section 16.2.

1.158 “PUCN Approval Date” means the date the PUCN Approval becomes effective pursuant to NAC §703.790.

1.159 “PUCN Approval Deadline” means December 31, 2019.

1.160 “QF” means a cogeneration or small power production facility that meets the criteria as defined in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207.

1.161 “Qualified Financial Institution” means a financial institution having an office in the United States, with a total tangible net worth of at least ten billion dollars ($10,000,000,000) U.S. and whose Credit Rating is at least “A-” by S&P and “A3” by Moody’s.
1.162 “Qualified Guarantor” means (a) Quinbrook Low Carbon Power Parallel Fund (US) LP and Quinbrook Low Carbon Power LP, or (b) an entity, which at the time it provides a Guarantee, either (i) meets Buyer’s minimum credit requirements as determined by Buyer in its sole and absolute discretion, or (ii) meets the Minimum Credit Rating.

1.163 “Qualified Operator” means (a) NextEra Energy Operating Services, LLC, or an Affiliate of NextEra Energy Resources, LLC with experience comparable to NextEra Energy Operating Services, LLC, (b) First Solar Electric, LLC, or an Affiliate of First Solar, Inc. with experience comparable to First Solar Electric, LLC, (c) Swinerton Renewable Energy, or (d) a Person that has at least three (3) years of experience operating a generating facility of at least 100 MW and of similar technology to the Generating Facility and at least two (2) years of experience operating a storage facility of at least 10 MW and similar technology to the Storage Facility approved by Buyer in its reasonable discretion.

1.164 “Qualified Transferee” means a Person that is at least as financially and operationally qualified as Supplier as of the Effective Date and, at a minimum, (a) has a tangible net worth of at least thirty million dollars ($30,000,000) or provides replacement Development Security or Operating Security to Buyer, as applicable, and (b) has (or agrees to contract with an operator who has) at least three (3) years of experience operating a generating facility of at least 100 MW and of similar technology to the Generating Facility and at least two (2) years of experience operating a storage facility of at least 10 MW and similar technology to the Storage Facility.

1.165 “Regulatory Penalties” means any penalties, fines, damages, or sanctions attributable to Supplier’s failure to perform under this Agreement and actually imposed on Buyer pursuant to an order issued by any Governmental Authority, the Transmission Provider or any Electric System Authority.

1.166 “Relevant Rating Agency” means Moody’s or S&P.

1.167 “Renewable Energy Benefits” means any and all renewable and environmental attributes, emissions reductions attributes, Portfolio Energy Credits (and any equivalent rights in any other jurisdictions), credits, offsets, allowances, reporting rights and benefits, howsoever entitled, and includes any and all: (a) available, allocated, assigned, awarded, certified or otherwise transferred or granted to Supplier or Buyer by the PC Administrator or any Governmental Authority in any jurisdiction in connection with the Facility or the generation, transmission or use of the Product, including those related to the Clean Air amendments of 1970 and regulations of the Environmental Protection Agency thereunder; (b) associated with the production of Energy or based in whole or part on the Facility’s use of renewable resources for generation or because the Generating Facility constitutes a Renewable Energy System or the like or because the Facility does not produce or produces less greenhouse gasses, regulated emissions or other pollutants, whether any such credits, offsets, allowances or benefits exist now or in the future and
whether they arise under existing Law or any future Law or whether such credit, offset, allowance or benefit or any Law, or the nature of such, is foreseeable or unforeseeable; (c) credits, offsets, allowances or benefits attributable to Energy generated and consumed by the Facility, such as Station Usage (parasitic load); (d) claims, credits, benefits, emissions, reductions, offsets, and allowances, however enticed, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water or generation of the Product, and include: (1) any avoided emissions of pollutants into the air, soil, or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (e) the Renewable Energy Benefits Reporting Rights. Renewable Energy Benefits exclude and do not include: (i) any Tax Credits or other Tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility; (ii) matters designated by Buyer as sources of liability; and (iii) adverse wildlife or environmental impacts.

1.168 “Renewable Energy Benefits Reporting Rights” means the exclusive right of a purchaser of Renewable Energy Benefits to report ownership of Renewable Energy Benefits in compliance with any applicable Law, and to Governmental Authorities or other Persons at such purchaser's discretion, and include reporting under: (a) Section 1605(b) of the Energy Policy Act of 1992; (b) the Environmental Protection Agency; (c) the Clean Air Act Amendments Section 111(d) and regulations thereunder; and (d) any present or future domestic, international or foreign emissions trading program or renewable portfolio standard.

1.169 “Renewable Energy Law” means an act of the Nevada Legislature relating to energy that requires certain electric service providers to comply with the portfolio standard for renewable energy, and providing for other matters relating thereto, codified as NRS §§ 704.7801 through 704.7828, inclusive, and the rules and regulations of WREGIS, and the regulations, guidance and other requirements promulgated thereunder, in each case, as such Laws, rules, regulations, guidance and other requirements may be amended, preempted or superseded from time to time.

1.170 “Renewable Energy System” means a generation facility that is both (a) a “renewable energy system” as defined in the Renewable Energy Law and (b) a “renewable Generating Unit” under WREGIS.

1.171 “Replacement Costs” means the Full Requirements Period Replacement Costs or Dispatchable Period Replacement Costs, as applicable.

1.172 “Required Facility Documents” means the Governmental Approvals, rights and agreements now or hereafter necessary for construction, operation and maintenance of the Facility set forth in Exhibit 12. Nothing set forth in Exhibit 12 limits
Supplier’s obligation to obtain the Governmental Approvals set forth in Exhibit 12 or otherwise required hereunder or with respect to the Facility.

1.173 “Resource-Adjusted Backcast Amount” means an amount determined for the Dispatchable Period by a backcasting analysis that takes into account weather conditions during the Dispatchable Period, including cloud cover, rain and snow impacting the solar resource, but assumes 100% operational availability of the Generating Facility; provided, however, that the Resource-Adjusted Backcast Amount for the Dispatchable Period of a Contract Year will not be greater than the Dispatch Availability Amounts (in MWh) for all hours in the Dispatchable Period of such Contract Year. The backcasting analysis will be performed by the Supplier using a tool, which will be mutually agreed upon by Buyer and Supplier in accordance with Exhibit 27 no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6. Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer. If the Parties disagree on the calculation of the Resource-Adjusted Backcast Amount, then the Resource-Adjusted Backcast Amount will be determined through the Dispute resolution provisions of Article 21.

1.174 “Restricted Period” is defined in Section 24.5.1.

1.175 “Restricted Transaction” is defined in Section 6.1.1.

1.176 “ROFO” is defined in Section 6.1.

1.177 “ROFO Period” is defined in Section 6.1.1.

1.178 “ROFO Seller” is defined in Section 6.1.1.

1.179 “Scheduled Amount” is defined in Section 14.2.1.

1.180 “Seller ROFO Notice” is defined in Section 6.1.1.

1.181 “Shortfall” means the Full Requirements Capacity Shortfall and/or the Dispatch Availability Shortfall, as applicable.

1.182 “Shared Facilities” means the shared permits, fences, access roads, buildings, or other equipment, permits, contract rights, and other assets and property (real or personal), in each case as necessary to enable delivery of Energy from the Facility (which is excluded from Shared Facilities) to the Delivery Points.

1.183 “Shortfall Amount” means the Full Requirements Capacity Shortfall Amount and/or the Dispatch Availability Shortfall Amount, as applicable.

1.184 “Standard and Poor’s” or “S&P” means Standard and Poor’s Ratings Group, a division of McGraw Hill, Inc., and any successor.
1.185 “Standby Service” means the electric service supplied by Nevada Power Company for Station Usage pursuant to Schedule LSR, Large Standby Service Rider, as such tariff is in effect and as may be amended from time to time.

1.186 “Station Usage” means all Energy used by the Facility with the exception of any energy used to charge the Storage Facility as provided herein.

1.187 “Storage Capacity” means the maximum dependable operating capability (in MWh) of the Storage Facility to store or discharge electric energy, and any other products that may be developed or evolve from time to time during the Term that relate to the maximum dependable operating capability of the Storage Facility to discharge electric energy.

1.188 “Storage Capacity Test” means the testing procedures, requirements and protocols set forth in Section 3.4.9 and Exhibit 25.

1.189 “Storage Contract Capacity” means the total capacity (in MW) of the Storage Facility determined in accordance with Section 3.4.9 and Exhibit 25, as the same may be adjusted from time to time pursuant to Section 3.4.9 and Exhibit 25.

1.190 “Storage Deficit Damages” is defined in Section 8.6.3.

1.191 “Storage Deficit Damages Rate” means six-hundred thousand dollars ($600,000) per MW.

1.192 “Storage Facility” means Supplier’s energy storage facility as described in Exhibit 1 (including the operational requirements of the energy storage facility), located at the Project Site as identified in Exhibit 3A and 3B and including mechanical equipment and associated facilities and equipment required to deliver Storage Product, including items as further described in Exhibits 1, 3A, 3B, 5 and 14, and as such storage facility may be expanded or otherwise modified from time to time in accordance with the terms hereof.

1.193 “Storage Facility Metering Points” means, with respect to Charging Energy, the points at the Storage Facility set forth in Exhibit 5.

1.194 “Storage Operating Procedures” is defined in Section 8.8 and set forth in Exhibit 24.

1.195 “Storage Product” means (a) Discharging Energy, (b) PCs (and any equivalent rights in any other jurisdiction), if any, (c) Renewable Energy Benefits, if any, (d) Storage Capacity, and (e) Ancillary Services, in each case arising from or relating to the Storage Facility.

1.196 “Stored Energy Level” means, at a particular time, the amount of energy in the Storage Facility available to Buyer, expressed in MWh.
1.197 “Stub Period” means the period of time commencing on the Commercial Operation Date and ending on December 31 of the year in which the Commercial Operation Date occurs (provided, however, that if the Commercial Operation Date occurs on January 1, then the term “Stub Period” will have no application to this Agreement).

1.198 “Supplier” is defined in the preamble of this Agreement and includes such Person’s permitted successors and assigns.

1.199 “Supplier’s Charging Energy” means all energy, including Energy produced by the Generating Facility, less transformation and transmission losses, if any, delivered to and measured at the Storage Facility Metering Points that is not Buyer’s Charging Energy or Full Requirements Period Charging Energy. Supplier’s Charging Energy shall be used as needed to power the Storage Facility’s Station Usage and other auxiliary loads.

1.200 “Supplier’s Lenders” means any Person other than an Affiliate of Supplier, and its permitted successors and assigns, providing money or credit to Supplier or an Affiliate (but only where and to the extent such Affiliate is receiving such money or credit for the purpose of funding Supplier or the development of the Facility) in connection with any development, bridge, construction, takeout, or permanent debt, tax equity or other financing or refinancing for the Facility, including lease, inverted lease, sale-leaseback, partnership-flip, monetization of tax benefits, back-leverage financing, or credit derivative arrangements.

1.201 “Supplier’s Required Regulatory Approvals” means the Governmental Approvals listed on Exhibit 10.

1.202 “Tax” or “Taxes” means any federal, state, local or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property (including assessments, fees or other charges based on the use or ownership of real property), personal property, transactional, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated tax, or other tax of any kind whatsoever, or any liability for unclaimed property or escheatment under common law principles, including any interest, penalty or addition thereto, whether disputed or not, including any item for which liability arises as a transferee or successor-in-interest.

1.203 “Tax Credits” means the PTC, ITC and any other state, local and/or federal production tax credit, depreciation benefit, tax deduction and/or investment tax credit specific to the production of renewable energy and/or investments in renewable energy facilities.

1.204 “Term” is defined in Section 2.2.

1.205 “Test Energy” is defined in Section 4.1.1.1.
1.206 “Test Product Rate” is defined in Section 4.1.1.1.

1.207 “Transmission Provider” means Nevada Power Company or any successor operator or owner of the Transmission System.

1.208 “Transmission Provider Instructions” means any instructions, requirements, or demands given by the Transmission Provider to Supplier or Buyer requiring the curtailment of the Facility for the purpose of operating, maintaining, improving or modifying the transmission or distribution system whether planned or unplanned, regardless of the amount advance notice provided to Supplier.

1.209 “Transmission System” means the facilities used for the transmission of electric energy in interstate commerce, including any modifications or upgrades made to such facilities, owned or operated by the Transmission Provider.

1.210 “Un-Dispatched Amount” is defined in Section 10.2.2.

1.211 “Weather Meter” is defined in Section 7.1.8.

1.212 “WECC” means the Western Electric Coordinating Council (formerly Western System Coordinating Council) and any successor.

1.213 “WREGIS” means the Western Renewable Energy Generation Information System and any successor.

1.214 “Yearly PC Amount” means the amount of PCs the Facility is expected to be capable of generating in a Contract Year as stated in Exhibit 18.

2. TERM; TERMINATION AND SURVIVAL OF OBLIGATIONS

2.1 Effective Date. Subject to Article 16, this Agreement shall become effective on the Effective Date.

2.2 Term. Supplier’s obligation to deliver Product, and Buyer’s obligation to accept and pay for Product, shall commence on the Commercial Operation Date and shall continue for a period of twenty-five (25) Contract Years, subject to earlier termination of this Agreement pursuant to the terms hereof (the “Term”); provided, however, that Buyer’s obligations to pay for or accept any Product are conditioned on the receipt of the PUCN Approval in form and substance acceptable to Buyer in its sole discretion. Buyer shall not be obligated to accept or pay for any Product, unless the PUCN Approval is received in form and substance acceptable to Buyer in its sole discretion or Buyer waives its right to terminate this Agreement pursuant to Article 16.

2.3 Termination.

2.3.1 For Cause. Except as provided below in this Section 2.3.1, this Agreement may be terminated at any time by the Non-Defaulting Party upon two (2)
Business Days' prior notice to the Defaulting Party if an Event of Default has occurred and is continuing (after the applicable Cure Period (if any) in Section 24.3 has expired); provided, however, that any purported termination by Supplier shall first require that Supplier deliver Notice to Buyer stating prominently therein in type font no smaller than 14 point all-capital letters that “THIS IS A TERMINATION NOTICE UNDER A RENEWABLE RESOURCE PPA. YOU MUST CURE A DEFAULT, OR THE PPA WILL BE TERMINATED,” and shall state therein any amount purported to be owed and wiring instructions. Notwithstanding any provision to the contrary contained in this Agreement, Supplier will not have any right to terminate this Agreement if the Event of Default that gave rise to the termination right is cured within fifteen (15) Business Days after receipt of such notice.

2.3.2 Failed Conditions Precedent. This Agreement may be terminated by Buyer in accordance with Article 16 without payment or penalty or liability of any kind.

2.3.3 Force Majeure. This Agreement may be terminated by Buyer if Supplier’s obligations hereunder have been excused by the occurrence of an event of Force Majeure for longer than twelve (12) consecutive months or three hundred sixty (360) days in any five hundred forty (540) day period.

2.4 Effect of Termination - Survival of Obligations. The termination or expiration of this Agreement shall not release either Party from any applicable provisions of this Agreement with respect to:

2.4.1 The payment of any amounts owed to the other Party arising prior to or resulting from termination or breach of this Agreement;

2.4.2 Indemnity obligations contained in this Agreement, including Article 18, which shall survive to the full extent of the statute of limitations period applicable to any third-party claim;

2.4.3 Limitation of liability provisions contained in Article 19;

2.4.4 For a period of two (2) years after the termination date, the right to submit a payment Dispute pursuant to Article 21; or

2.4.5 The resolution of any Dispute submitted pursuant to Article 21 prior to, or resulting from, termination.

3. SUPPLY SERVICE OBLIGATIONS

3.1 Dedication. One hundred percent (100%) of the Product from the Facility shall be dedicated exclusively to Buyer for so long as this Agreement is in force and effect. Subject to Section 24.2, Supplier shall not: (a) sell, divert, grant, transfer or assign Product to any Person other than Buyer; (b) provide Buyer with any Product from
any source other than the Facility; or (c) divert, redirect or make available the Facility or any resource therefrom to another generating facility or storage facility or any third party. The Parties agree that remedies at Law may be inadequate in the event of a breach of this Section 3.1, and Supplier agrees that Buyer shall be entitled, without proof of actual damages and without necessity of posting bond or other security, to temporary, preliminary and permanent injunctive relief from any Governmental Authority of competent jurisdiction restraining Supplier from committing or continuing any breach of this Section 3.1.

3.2 **Purchase and Sale.** For and in consideration of Buyer’s payment for the Product, Supplier sells to Buyer, and Buyer purchases from Supplier, all rights, title and interest that Supplier may have in and to the Product, including Capacity Rights, Ancillary Services and Renewable Energy Benefits on all Energy (including Excess Energy and the Un-Dispatched amount as applicable) existing during the Term.

3.3 **No Double Sales.** Supplier represents that it has not sold, and covenants that during the Term it will not sell or attempt to sell to any other Person, the Product, including the Capacity Rights, if any, and the Renewable Energy Benefits on all Energy (including Excess Energy and the Un-Dispatched Amount, as applicable) existing during the Term, whether Buyer has scheduled Product or not, other than as provided in Section 24.2. During the Term, Supplier shall not report to any person or entity that the Product, including the Capacity Rights, if any, and the Renewable Energy Benefits on all Energy (including Excess Energy) existing during the Term, belong to anyone other than Buyer. Buyer may report to any person that it exclusively owns the Product, including the Capacity Rights, if any, the Ancillary Services and the Renewable Energy Benefits on all Energy (including Excess Energy) existing during the Term. At Buyer’s request, the Parties shall execute such documents and instruments as may be reasonably required to effect recognition and transfer of the Capacity Rights, if any, to Buyer.

3.4 **Delivery Responsibilities.**

3.4.1 **Product.** Subject to the provisions of this Agreement, commencing on the Commercial Operation Date and throughout the Term, Supplier shall supply and deliver the Product to Buyer at the Delivery Points (other than Buyer’s Charging Energy which shall be delivered at the Storage Facility Metering Points).

3.4.2 **Delivered Amount.** Buyer shall take delivery of the Energy, including any Excess Energy, and Discharging Energy at the Delivery Points in accordance with the terms of this Agreement. Supplier shall be responsible for paying or satisfying when due all costs or charges imposed in connection with the scheduling and delivery of Energy and Discharging Energy up to the Delivery Points, including transmission costs, transmission line losses, any costs or charges imposed in connection with scheduling and delivery of the Charging Energy to the Storage Facility Metering Points and any operation and maintenance charges imposed by the Transmission Provider. Buyer shall be responsible for all costs or
charges, if any, imposed in connection with the delivery of Energy and Discharging Energy at and after the Delivery Points, including transmission costs and transmission line losses and imbalance charges. Without limiting the generality of the foregoing, Buyer, in its merchant capacity, shall not bear costs associated with the modifications to the Transmission System (including system upgrades) caused by or related to: (a) the interconnection of the Facility with the Transmission System; and (b) any increase in generating capacity of the Generating Facility. The Parties agree that the terms of the IA shall govern the allocation of costs associated with any modifications or upgrades to the Transmission System. To the extent any terms of this Agreement conflict with the IA, the terms of the IA shall prevail.

3.4.3 Title and Risk of Loss. Title and risk of loss with respect to Energy and Discharging Energy delivered by Supplier shall pass from Supplier to Buyer at the Delivery Points. Supplier shall be deemed in exclusive control of the Energy and Discharging Energy and shall be responsible for any damage or injury caused prior to the Delivery Points. Buyer shall be deemed in exclusive control of the Energy and Discharging Energy and shall be responsible for any damage or injury caused at and after the Delivery Points. Supplier warrants that all Product delivered to Buyer is free and clear of all liens, security interests, claims and encumbrances of any kind.

3.4.4 Provisional Energy Delivery. Buyer may request by written notice to Supplier to deliver Provisional Energy prior to the Commercial Operation Date, in increments as defined in Section 1.154, and on and after a specified date. Supplier may, in its sole discretion, elect to deliver such Provisional Energy to Buyer by delivering written notice thereof to Buyer. Notwithstanding the foregoing, Buyer and Supplier shall mutually agree on the amounts of Provisional Energy to be supplied and the date and time when such Provisional Energy shall be supplied.

3.4.5 Voltage Support. The IA requires the Facility to maintain a composite power delivery at continuous rated power output at the points of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to the Facility and all generators in the control area on a comparable basis. In addition to the requirements of the IA, the Facility will provide voltage set point control at the points of interconnection within the range of 0.90 leading to 0.90 lagging, as available. If Buyer requests reactive power or a voltage set-point outside the Generating Facility’s capacity at its currently dispatched real power set-point, Buyer will dispatch the Generating Facility downward to a set-point that permits the desired reactive power within the capabilities of the Facility. The amount of Energy that could have been but was not produced due to such dispatch down shall be an Un-Dispatched Amount if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full
Requirements Period. In furtherance of the requirements of the IA, the Facility will provide voltage set point control at the point of interconnection for the scheduled real-power output, as available, within the capabilities of the Facility shown in Exhibit 22. The Facility shall provide dynamic reactive power as required for voltage regulation twenty-four (24) hours per day, if the Facility is capable of providing reactive power, regardless of real power output. The performance of reactive power output to provide voltage support shall be according to unit real/reactive capability curves provided in Exhibit 22.

3.4.6 Dispatchable Accuracy Rate. During the Dispatchable Period, Supplier shall meet the Dispatchable Accuracy Rate subject to Section 3.6.2.

3.4.7 Automated Generation Control. Subject to Section 3.6.2, during the Dispatchable Period, Supplier shall ensure that the Generating Facility is able to be dispatched by Buyer’s Energy Management System sending signals to Supplier’s AGC so that the Generating Facility can be dispatched dynamically. The energy dispatched in this manner is the “Dispatched Amount.”

3.4.8 Charging Energy Management.

3.4.8.1 During the Dispatchable Period (excluding the months of June, July and August), Supplier shall take any and all action necessary to deliver Buyer’s Charging Energy to the Storage Facility in order to deliver the Storage Product in accordance with the terms of this Agreement, including maintenance, repair or replacement of equipment in Supplier’s possession or control used to deliver Buyer’s Charging Energy from the Generating Facility to the Storage Facility.

3.4.8.2 Subject to the requirements and limitations set forth in this Agreement, including the Storage Operating Procedures and Supplier’s right to charge the Storage Facility using Supplier’s Charging Energy and to charge the Storage Facility in order to meet Supplier’s obligations during the Full Requirements Period, during the Dispatchable Period (excluding the months of June, July and August), Buyer will have the right to charge the Storage Facility seven (7) days per week and twenty-four (24) hours per day (including holidays), by providing Charging Notices to Supplier electronically; provided that the Generating Facility is producing Energy, the Charging Notice does not request a Stored Energy Level that exceeds the Energy available, and the Charging Notice is otherwise compliant with the Storage Operating Procedures. Each Charging Notice will be effective unless and until Buyer modifies such Charging Notice by providing Supplier with an updated Charging Notice.
Notice. If an electronic submittal is not possible for reasons beyond Buyer’s control, Buyer may provide Charging Notices by (in order or preference, unless the Parties agree to a different order) electronic mail, facsimile transmission or telephonically to Supplier’s personnel designated in Exhibit 4 to receive such communications. Notwithstanding the above, Buyer shall not have the right to send a Charging Notice during the months of June, July or August or to charge the Storage Facility with energy that is not generated by the Generating Facility.

3.4.8.3 Supplier shall not charge the Storage Facility during the Dispatchable Period (excluding the months of June, July and August) other than pursuant to a Charging Notice, in connection with a Storage Capacity Test, using Supplier’s Charging Energy, or as required by Supplier to meet Supplier’s obligations during the Full Requirements Period in accordance with Section 14.2.4. If during the Dispatchable Period (excluding the months of June, July and August), Supplier charges the Storage Facility except as provided in the preceding sentence, then (x) Supplier shall be responsible for all costs associated with the additional energy in the Storage Facility due to such unauthorized charging (“Excess Charging Energy”), (y) Buyer shall not be required to pay for such Excess Charging Energy, and (z) Buyer shall be entitled to use such Excess Charging Energy and to all of the benefits (including Storage Product) associated with discharging such Excess Charging Energy. During the months of June, July and August, Supplier may charge the Storage Facility as it determines in its sole discretion.

3.4.9 Storage Capacity Tests.

3.4.9.1 Prior to the Commercial Operation Date, Supplier shall schedule and complete one or more Storage Capacity Tests in accordance with Exhibit 25. Thereafter, at least once per Contract Year, Supplier shall schedule and complete a Storage Capacity Test in accordance with Exhibit 25. Buyer shall have the right to run a retest of the Storage Capacity Test in accordance with Exhibit 25. Supplier shall have the right to run one or more retests of the Storage Capacity Test in accordance with Exhibit 25.

3.4.9.2 Buyer shall have the right to send one or more representative(s) to witness all Storage Capacity Tests. Buyer shall be responsible for all costs, expenses and fees payable or reimbursable to its representative(s) witnessing
any Storage Capacity Test. All other costs of any Storage Capacity Test shall be borne by Supplier (other than any third party costs incurred by Supplier for any retest required by Buyer pursuant to Section 3.4.7, unless such retest shall result in the Storage Contract Capacity being reduced from the Storage Contract Capacity established by the immediately preceding Storage Capacity Test, in which case Supplier shall be responsible for such costs).

3.4.9.3 Following each Storage Capacity Test, Supplier shall submit a testing report to Buyer in accordance with Exhibit 25 and reasonable support data requested by Buyer. If the actual capacity determined pursuant to a Storage Capacity Test is less than the then current Storage Contract Capacity, then the actual capacity determined pursuant to such Storage Capacity Test shall become the new Storage Contract Capacity at the beginning of the day following the completion of the test for all purposes under this Agreement until a new Storage Contract Capacity is determined pursuant to a subsequent Storage Capacity Test, provided, that (a) in no event shall the Storage Contract Capacity be revised more frequently than monthly, and (b) the Storage Contract Capacity cannot exceed three hundred eighty (380) MW.

3.4.10 Storage Availability.

3.4.10.1 During the months of January through May and September through December (the “Dispatch Availability Months”) of the Term, the Storage Facility shall maintain a Monthly Storage Availability of no less than ninety-eight percent (98%) (the “Guaranteed Storage Availability”), which Monthly Storage Availability shall be calculated in accordance with Exhibit 26.

If the Monthly Storage Availability during the Dispatch Availability Months is less than the Guaranteed Storage Availability, then Supplier shall cure such failure by paying to Buyer Availability Liquidated Damages calculated in accordance with Exhibit 26. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such Availability Liquidated Damages in accordance with Exhibit 26.

3.4.10.2 The Parties recognize and agree that the payment of amounts by Supplier pursuant to this Section 3.4.10 is an appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes
anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that the amount payable by Supplier pursuant to this Section 3.4.10 is difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient and the damages calculated hereunder constitute a reasonable approximation of the harm or loss.

3.5 Renewable Energy System. Notwithstanding anything in this Agreement to the contrary, Buyer shall not be obligated to purchase or accept delivery of Product if the Generating Facility: (a) is not at the time of delivery qualified as a Renewable Energy System; or (b) is not delivering to Buyer all of the Renewable Energy Benefits generated with the Net Energy and Discharging Energy being delivered; provided that if there is a change in the Renewable Energy Law after the execution of this Agreement that causes the Net Energy and Discharging Energy from the Generating Facility to be ineligible or non-qualifying as a Renewable Energy System under such Renewable Energy Law, Supplier shall use commercially reasonable efforts to comply with such Renewable Energy Law. For purposes hereof, commercially reasonable efforts shall include the expenditure of amounts up to six hundred ninety thousand dollars ($690,000) (the “Compliance Cost Cap”) in any Contract Year. If Supplier reasonably concludes that it may incur costs in excess of the Compliance Cost Cap in any Contract Year in order to comply with the Renewable Energy Law, it shall provide Buyer with a notice itemizing such excess costs. Buyer shall evaluate such notice and either: (i) agree to reimburse Supplier for such excess costs (the “Accepted Compliance Costs”); or (ii) waive Supplier’s obligation to comply with the Renewable Energy Law to the extent such inability results from failing to expend amounts in excess of the Compliance Cost Cap. If Buyer agrees to reimburse Supplier for the Accepted Compliance Costs, then Supplier shall be required to comply in full with the Renewable Energy Law, and Buyer shall reimburse Supplier for Supplier’s actual and reasonable out-of-pocket compliance costs in excess of the Compliance Cost Cap, not to exceed the Accepted Compliance Costs. If Supplier’s inability to comply with the Renewable Energy Law cannot be cured by the expenditure of money, such noncompliance shall be excused and shall not constitute an Event of Default, and Buyer’s payment obligations to Supplier hereunder shall not be excused or reduced in any manner.

3.6 Shortfall; Replacement Costs; DAR. Supplier shall pay Buyer Replacement Costs, DAR Threshold remedies and any Regulatory Penalties, if any, incurred as a result of any Shortfall in any Measurement Period in accordance with the following provisions:

3.6.1 Dispatchable Period Shortfall.

3.6.1.1 If (a) the sum of all Delivered Amounts, and all Excused Product for the Dispatchable Period during a Measurement Period is less than (b) (i) ninety-five hundredths (0.95), multiplied by (ii) the Resource-Adjusted Backcast Amount minus the Full Requirements Period Charging Energy for the Dispatchable Period during such
Measurement Period, then an availability shortfall (a “Dispatch Availability Shortfall”) will be deemed to exist for such Dispatchable Period equal to (b) minus (a) (the “Dispatch Availability Shortfall Amount”).

3.6.1.2 Buyer’s “Dispatchable Period Replacement Costs” with respect to any Dispatchable Period in any Measurement Period for which there is a Dispatch Availability Shortfall shall equal the product of (a) the Dispatch Availability Shortfall Amount for such Dispatchable Period, multiplied by (b) an amount equal to the positive difference, if any, between the Market Price for such Dispatchable Period minus the Dispatchable Period Product Rate.

3.6.1.3 Within five (5) Business Days after the end of any Measurement Period in which a Dispatch Availability Shortfall has occurred, Supplier shall calculate the Dispatchable Period Replacement Costs with respect to such Dispatch Availability Shortfall Amount and provide Buyer with written notice of such calculation. Such Dispatchable Period Replacement Costs shall be reflected on the Invoice for the same Billing Period in which such Dispatchable Period Replacement Costs are calculated.

3.6.2 Dispatchable Accuracy Rate.

3.6.2.1 In the event the Generating Facility’s DAR is less than ninety-seven percent (97%) (“DAR Threshold”) for any calendar month during the Dispatchable Period, and not to exceed any three (3) consecutive calendar months, Buyer will not pay Supplier for an amount of megawatt hours equal to the product of (a) 0.97, less the Generating Facility’s DAR for such month, expressed as a decimal, and (b) the Dispatched Amount for such month (the “Deviation Amount”). For the Invoice immediately following any such calendar month that includes a Deviation Amount, the invoiced amount shall be reduced by an amount equal to the Deviation Amount multiplied by the applicable Dispatchable Period Product Rate.

3.6.2.2 If after three (3) consecutive months the Generating Facility does not meet the DAR Threshold for the fourth (4th) consecutive month or for any consecutive month thereafter through the sixth (6th) consecutive month, Buyer shall only pay Supplier for the Dispatched Amount during such months (and shall not be obligated to compensate Supplier for any Un-Dispatched Amount in such months).

3.6.2.3 If after six (6) consecutive months but not to exceed twelve (12) consecutive months the Generating Facility does not meet the DAR Threshold for each such consecutive month after the sixth (6th) consecutive month, Supplier shall only be entitled to receive 75% of
the Dispatchable Period Product Rate for the Dispatched Amount during such months and Buyer shall only pay Supplier for the Dispatched Amount during such months (and shall not be obligated to compensate Supplier for any Un-Dispatched Amount in such months).

3.6.2.4 If after twelve (12) consecutive months the Generating Facility’s DAR is less than the DAR Threshold for each such month then Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.7.

3.6.2.5 If Supplier fails to meet the DAR Threshold for any thirty-six (36) non-consecutive months during the Dispatchable Periods of the Term, Buyer will have the right to terminate this Agreement pursuant to Section 24.1.8.

3.6.3 Full Requirements Period Over Delivery.

3.6.3.1 If for any Full Requirements Period, the Delivered Amount is greater than the Full Requirements Period Product by more than five (5%) percent, then the Delivered Amount in excess of such five (5%) percent threshold is the “Over Delivery Amount.”

3.6.4 Full Requirements Capacity Shortfall.

3.6.4.1 If for any Full Requirements Period of a Contract Year, (a) the Delivered Amount plus Excused Product during the Full Requirements Period is less than (b) ninety-five hundredths (0.95) multiplied by the Full Requirements Period Product, then a shortfall (a “Full Requirements Capacity Shortfall”) will be deemed to exist for such Full Requirements Period equal to (b) minus (a) (the “Full Requirements Capacity Shortfall Amount”). Supplier shall pay Replacement Costs for such Full Requirements Capacity Shortfall Amount equal to the product of (x) Full Requirements Capacity Shortfall Amount, times (y) an amount equal to the positive difference (if any) between the Market Price for the Full Requirements Period minus the Full Requirements Period Product Rate (the result of such calculation, the “Full Requirements Period Replacement Costs”, which shall not be less than zero).

3.6.4.2 If in a second (2nd) consecutive Full Requirements Period, Supplier incurs another Full Requirements Capacity Shortfall, then for the purpose of calculating payment to Supplier in the immediately successive Invoice, such invoiced amount shall be reduced by an amount equal to: (i) the Full Requirements Capacity Shortfall for such second (2nd) consecutive Full Requirements Period multiplied by (ii) the applicable Full Requirements Period Product Rate. If this reduction results in a negative Invoice amount, subsequent Invoices
will be reduced until the entire reduction amount calculated pursuant to this Section 3.6.4.2 has been recovered by Buyer.

3.6.4.3 If after the second (2nd) consecutive Full Requirements Period described in Section 3.6.4.2, Supplier incurs a third (3rd) Full Requirements Capacity Shortfall, Supplier shall pay the amount calculated using the methodology in Section 3.6.4.2 for such third (3rd) consecutive Full Requirements Period, and Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.9. Buyer’s termination right must be exercised, if at all, within one hundred eighty (180) days after the end of such third (3rd) consecutive Full Requirements Period. If Buyer does not terminate and for consecutive subsequent Full Requirements Periods thereafter a Full Requirements Capacity Shortfall occurs, Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.9 after each such consecutive subsequent Full Requirements Period until the occurrence of a Full Requirements Period in which Supplier does not have a Full Requirements Capacity Shortfall, after which time the termination right will reset and Supplier will have to have three (3) consecutive Full Requirements Periods with Full Requirements Capacity Shortfalls for Buyer again to have the termination right defined in this Section 3.6.4.3 and Section 24.1.9.

3.6.4.4 Within five (5) Business Days after the end of any Full Requirements Period in which a Full Requirements Capacity Shortfall has occurred, Supplier will calculate the Full Requirements Period Replacement Costs with respect to such Full Requirements Capacity Shortfall and provide Buyer with written notice of such calculation. Such Replacement Costs shall be reflected on the Invoice immediately subsequent to the Full Requirements Period and will reflect any set-off or true-ups in accordance with this Agreement.

3.6.5 Not a Penalty. The Parties recognize and agree that the remedies that Buyer has against Supplier pursuant to this Section 3.6 are appropriate remedies and that any such remedy (including liquidated damages) does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that Buyer’s damages for the failure of Supplier to perform any of its obligations under sections 3.6.1, 3.6.2 and 3.6.3 are difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient, and the remedies and any amounts applying to any of them as calculated thereunder constitute a reasonable approximation of the harm or loss to Buyer.

3.6.6 Calculations. As soon as practicable following any period of: (a) Force Majeure; (b) Buyer’s failure to accept Net Energy or PCs in breach of this Agreement; (c) Emergency (except as provided in Section 9.4); (d) Planned
Outage; (e) Curtailed Product; (f) Transmission Provider Instructions; (g) an Un-Dispatched Amount, or (h) FRP Deemed Delivered Energy, in each case, as a result of which Supplier has failed to deliver any portion of the Product to Buyer during such period and, subject to the terms of this Agreement, such failure and Supplier’s liability for damages therefor are excused, Supplier shall calculate the amount of Net Energy that Supplier was unable to generate, or discharge if any portion of such period occurs during the Full Requirements Period, solely as a result of such event, by summing for each hour of the period the difference between (i) the Availability Backcast Amount, plus any Discharging Energy that could have been delivered for each hour during the Full Requirements Period but was not delivered due to one or more events described in this Section 3.6.6, and (ii) the Delivered Amount during each hour (the “Excused Product”).

3.7 PC Shortfall; PC Replacement Costs.

3.7.1 If after the PC Administrator issues all the PC statements or certificates for any Contract Year there is a PC Shortfall, then Supplier shall pay Buyer for the replacement costs and any Regulatory Penalties associated with such PC Shortfall (collectively, the “PC Replacement Costs”). Subject to the last sentence of this Section 3.7.1, for purposes of this Agreement a “PC Shortfall” shall occur in any Contract Year if the sum of all Delivered PCs is less than the “PC Shortfall Threshold” defined as the product of (a) 0.90 multiplied by (b) an amount equal to (i) the Yearly PC Amount for the Contract Year, minus (ii) the total amount of PCs associated with Excused Product during such Contract Year. For purposes of this Agreement, a “PC Shortfall Amount” with respect to any Contract Year means: (A) the PC Shortfall Threshold for such Contract Year; minus (B) the Delivered PCs during such Contract Year. If the calculation of the PC Shortfall Amount set forth in this Section 3.7.1 yields an amount of zero or less for any Contract Year, then no PC Shortfall will be deemed to exist with respect to such Contract Year.

3.7.2 The PC Replacement Costs shall be determined by Buyer exercising its reasonable discretion based on the estimated cost of purchasing PCs to replace the PC Shortfall Amount from the same resource type with a comparable expiration date or the cost of replacing the PC Shortfall Amount with PCs of Buyer’s choice already in Buyer’s PC Account; provided, however, that Buyer shall not be required to actually purchase replacement PCs in order to receive payment from Supplier for PC Replacement Costs. Buyer shall include in the PC Replacement Costs any Regulatory Penalties allocable to Supplier’s proportionate amount of Buyer’s aggregate shortfall under the applicable Portfolio Standard (factoring in Supplier’s PC Shortfall Amount in prior years carried forward as a deficit or reducing the surplus in such prior years).

3.7.3 The Parties recognize and agree that the payment of amounts by Supplier pursuant to this Section 3.7 is an appropriate remedy and that any such
payment does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that the amount payable by Supplier pursuant to this Section 3.7 is difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient and the damages calculated hereunder constitute a reasonable approximation of the harm or loss.

3.7.4 All information used by Buyer to establish PC Replacement Costs shall be verifiable by Supplier; and Buyer shall provide reasonable access to all such information supporting calculations within five (5) Business Days of Supplier’s request for such information. Supplier agrees to execute a confidentiality agreement regarding the review of this information upon request by Buyer.

3.7.5 For any Contract Year, Buyer, at its sole option, may allow Supplier to meet its PC Replacement Cost obligation by transferring a quantity of PCs to Buyer in the amount of no less than the PC Shortfall Amount. Such PCs shall be from the same resource type with a comparable expiration date as the PCs that should have been delivered to Buyer under this Agreement.

3.8 **Supply Degradation.** Beginning with the second Contract Year, and each Contract Year thereafter, (a) the Dispatch Availability Amount and the Maximum Amount shall be reduced by five-tenths of a percent (0.5%), and (b) the Yearly PC Amount shall be reduced by seven-tenths of a percent (0.7%), in each case, such that the applicable amount is reduced by such percentage using the prior year adjusted amount (i.e. after the reduction for the prior year has been applied) as the base amount to which the percentage is applied. No later than January 1 of each Contract Year Buyer shall deliver to Supplier revised Exhibits 13 and 18 which shall reflect such reductions, and effective as of January 1 of each Contract Year this Agreement shall automatically be amended to substitute such revised Exhibits 13 and 18 for the then existing Exhibits 13 and 18.

4. **PRICE OF PRODUCT**

4.1 **Product Payments.** Supplier shall be paid for the Product as follows:

4.1.1 **Prior to the Commercial Operation Date.**

4.1.1.1 On and after the Operation Date and prior to the Commercial Operation Date, all Product associated with Delivered Amounts of Net Energy from the Generating Facility, other than (a) Excess Energy (which shall not be compensable) and (b) Provisional Energy, shall be considered “Test Energy” and shall be paid for by Buyer at the lesser of: (i) fifty percent (50%) of the applicable Product Rate; or (ii) the Market Price for each Delivery Hour of Test Energy (“Test Product Rate”).
4.1.1.2 Notwithstanding the above, if Buyer requests Supplier to deliver Provisional Energy and Supplier elects to deliver Provisional Energy and delivers written notice to Buyer that it is delivering Provisional Energy in accordance with Section 3.4.4, Buyer shall pay Supplier seventy-five percent (75%) of the applicable Product Rate ("Provisional Product Rate") for such Provisional Energy.

4.1.1.3 Provisional Energy shall be distinguished from Test Energy in so far as Provisional Energy is for a determined amount of energy provided as the Generating Facility is capable of consistently generating such amounts of energy, whereas Test Energy is energy generated after the Operation Date and prior to Commercial Operation that is needed to commission the Generating Facility. Supplier shall provide notice when Provisional Energy is available and Buyer and Supplier shall mutually agree to the date and time when Provisional Energy requested by Buyer and agreed to by Supplier shall be supplied in accordance with Section 3.4.4. Five (5) Business Days prior to the start of each month, beginning with the month in which the Operation Date is expected to occur, Supplier shall provide notice to Buyer with an estimate of the forecasted amounts of Test Energy and Provisional Energy for that month with correlated meter data for actual amounts of Test Energy and Provisional Energy amounts to be provided with invoicing. Such determination shall be subject to verification by Buyer in the exercise of its reasonable discretion.

4.1.2 Subsequent to the Commercial Operation Date. On and after the Commercial Operation Date:

4.1.2.1 All Product associated with Delivered Amounts of Net Energy from the Generating Facility, other than Excess Energy, shall be paid for by Buyer at the applicable Product Rate set forth in Exhibit 2A and based on the quantity of Net Energy; provided that such payment constitutes the entirety of the amount due to Supplier from Buyer for the Product associated with Delivered Amounts of Net Energy other than Excess Energy; provided further that Supplier shall be paid at the Test Product Rate for the month in which the Commercial Operation Date occurs if the Commercial Operation Date occurs on or after the sixteenth (16th) day of such month.

4.1.2.2 All Un-Dispatched Amount of Product shall be paid for at the Dispatchable Period Product Rate in consideration for Ancillary Services and Capacity.
4.1.2.3 All Product associated with Excess Energy shall be paid for at the Test Product Rate.

4.1.2.4 All FRP Deemed Delivered Energy shall be paid for at the Full Requirements Period Product Rate.

4.1.2.5 The payment for all Storage Product is included in payments for the applicable Product Rates.

4.1.2.6 All Over Delivery Amounts shall be paid for at three (3) times the Dispatchable Period Product Rate for the Over Delivery Amount.

4.1.3 No payment shall be owing to Supplier for any Product associated with Energy that is for any reason not Net Energy except as otherwise provided in Section 4.1.2.2 and Section 4.1.2.4.

4.1.4 Buyer shall not be required to accept from Supplier any Product associated with Delivered Amounts (excluding Buyer’s Charging Energy) of Net Energy from the Generating Facility delivered during any Delivery Hour in excess of the Delivery Points Maximum Amount and no payment shall be owing to Supplier for any Product associated with Delivered Amounts (excluding Buyer’s Charging Energy) of Net Energy from the Generating Facility accepted by Buyer during any Delivery Hour in excess of the Delivery Points Maximum Amount.

4.2 **Excused Product.** Buyer shall not pay for Product comprising Excused Product except for Excused Product described in Sections 3.6.6(b), (g) and (h).

4.3 **Tax Credits.** The Parties agree that neither any Product Rate nor the Test Product Rate are subject to adjustment or amendment if Supplier fails to receive any Tax Credits, or if any Tax Credits expire, are repealed or otherwise cease to apply to Supplier or the Facility in whole or in part, or Supplier or its investors are unable to benefit from any Tax Credits. Supplier shall bear all risks, financial and otherwise, throughout the Term, associated with Supplier’s or the Facility’s eligibility to receive Tax Credits or to qualify for accelerated depreciation for Supplier’s accounting, reporting or Tax purposes. The obligations of the Parties hereunder, including those obligations set forth herein regarding the purchase and price for and Supplier’s obligation to deliver Net Energy and Discharging Energy and Product, shall be effective regardless of whether the sale of Energy or Net Energy from the Facility is eligible for, or receives Tax Credits during the Term.

5. **PORTFOLIO ENERGY CREDITS/RENEWABLE ENERGY BENEFITS**

5.1 **Delivery of Renewable Energy Benefits and Portfolio Energy Credits.**

5.1.1 All Renewable Energy Benefits are exclusively dedicated to and vested in Buyer. Supplier shall deliver to Buyer all Renewable Energy Benefits derived from the Facility, including Renewable Energy Benefits associated
with Energy for Station Usage, if any. Supplier shall timely prepare and execute all documents and take all actions necessary under Law or the requirements of any Governmental Authority or Person and otherwise to cause the Renewable Energy Benefits to vest in Buyer, without further compensation, including: (a) taking all actions necessary to register or certify any Renewable Energy Benefits or the Facility with the PUCN or any other Person (pursuant to NAC 704.8921 or otherwise) and WREGIS; (b) causing the automatic transfer of the Renewable Energy Benefits derived from the Facility to Buyer (pursuant to NAC 704.8927 or otherwise); (c) providing all production data and satisfying the reporting requirements of the PUCN or PC Administrator, as applicable; and (d) cooperating in any registration by Buyer of the Facility in any other renewable portfolio standard or equivalent program in any states in which Buyer may wish to register or maintain registration of the Facility, including providing copies of all such information as Buyer reasonably requires for such registration. Without limitation of the foregoing, Supplier acknowledges that the Renewable Energy Benefits, may be used by Buyer in meeting its present and future obligations pursuant to applicable Law, including the Portfolio Standard, and agrees to cooperate with Buyer to assist in Buyer’s compliance with all applicable requirements set forth in the Portfolio Standard and provide all information reasonably requested by Buyer or otherwise necessary to allow the PUCN to determine compliance with the Portfolio Standard. No Person other than Buyer (or its designee) will be entitled to claim Renewable Energy Benefits in any jurisdiction in connection with the Facility. All representations and warranties made by Supplier with respect to Renewable Energy Benefits are freely transferrable by Buyer to any purchaser or transfee of such Renewable Energy Benefits or part thereof.

5.1.2 On or before January 31 of each year following the Operation Date, Supplier, as owner or operator of the Renewable Energy System, shall deliver to Buyer a written attestation for the prior year that no part of the Renewable Energy Benefits: have been or will be (a) used for or by any Person to obtain renewable energy credit in any state or jurisdiction, except for Buyer pursuant to this Agreement; (b) sold or otherwise exchanged for compensation or used for credit in any other state or jurisdiction; and (c) included within a blended energy product certified to include a fixed percentage of renewable energy in any other state or jurisdiction, pursuant to Chapter 704 of the NAC. No Person other than Buyer (or its designee) will be entitled to claim Portfolio Energy Credits, Renewable Energy Benefits (or equivalents in any jurisdiction) in connection with the Facility.

5.2 Injunction. If any Person other than Buyer (or its designee) attempts to claim such Renewable Energy Benefits or part thereof, the Parties agree that remedies at Law may be inadequate to protect Buyer in the event of a breach of this Section 5.2, and Supplier hereby in advance agrees: (a) that Buyer shall be entitled to seek without proof of actual damages or the necessity of posting any bond or other security, temporary, preliminary and permanent injunctive relief from any Governmental
Authority of competent jurisdiction restraining Supplier from committing or continuing any breach of this Section 5.2; and (b) that Supplier will promptly undertake all necessary actions to prevent such other Person from claiming such Renewable Energy Benefits (including joining with or otherwise assisting Buyer in seeking the relief described in clause (a)).

5.3 Transfers. Buyer shall be entitled to PC Replacement Costs for Renewable Energy Benefits associated with any Energy for which WREGIS Certificates, PCs or any part of the Renewable Energy Benefits that are not delivered to Buyer. Supplier shall promptly give Buyer copies of all documentation it submits to WREGIS or PUCN or otherwise with respect to Renewable Energy Benefits. Further, in the event of the promulgation of a scheme involving any part of the Renewable Energy Benefits administered by CAMD, upon notification by CAMD that any transfers contemplated by this Agreement will not be recorded, the Parties shall promptly cooperate in taking all reasonable actions necessary so that such transfers can be recorded. Supplier shall not report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program that any of the Renewable Energy Benefits belong to any person other than Buyer. Without limiting the generality of Buyer’s ownership of the Renewable Energy Benefit Reporting Rights, Buyer may report under such program that all Renewable Energy Benefits purchased hereunder belong to it. Each Party shall promptly give the other Party copies of all documents it submits to the CAMD to effectuate any transfers.

6. RIGHT OF FIRST OFFER; RIGHT OF FIRST REFUSAL; EARLY PURCHASE OPTION; END OF TERM PURCHASE OPTION

6.1 Right of First Offer ("ROFO").

6.1.1 Except in accordance with this Article 6, Supplier: (a) shall not sell, transfer or offer or negotiate to sell or transfer, the Facility; and (b) shall cause its immediately upstream owner(s) (together with Supplier, each a "ROFO Seller") not to sell, transfer or offer or negotiate to sell or transfer, any ownership interest in Supplier (the Facility and ownership interests in Supplier, each the "Offered Interests") other than to an Affiliate in accordance with the provisions of Section 23.2 and other than a Supplier’s Lenders Transaction (each a "Restricted Transaction"). For purposes hereof, a "Supplier’s Lenders Transaction" means any transaction between Supplier or its Affiliates, on the one hand, and Supplier’s Lenders, on the other hand. If a ROFO Seller intends to enter into a Restricted Transaction, Supplier shall provide Buyer with written notice of same (a "Seller ROFO Notice"), and Buyer shall have a right of first offer with respect to the purchase of such Offered Interests. Within fifteen (15) days, if prior to Commercial Operation Date, or thirty (30) days if on or after the Commercial Operation Date, after receipt of the Seller ROFO Notice, Buyer shall notify Supplier in writing of its decision whether or not to negotiate with ROFO Seller for the purchase of the Offered Interests (the "Buyer ROFO Notice"). If Buyer elects to negotiate with ROFO Seller for the purchase of the Offered Interests, Supplier shall cause ROFO Seller to
negotiate in good faith and exclusively with Buyer, for a period of not less than sixty (60) days, if prior to Commercial Operation Date, or ninety (90) days if on or after the Commercial Operation Date, following ROFO Seller’s receipt of the Buyer ROFO Notice, the terms of a purchase by Buyer or its designee of the Offered Interests (such fifteen (15) day or thirty (30) day period as extended, if applicable, by such sixty (60) day period, or ninety (90) day period as applicable the “ROFO Period”). NV Energy may seek PUCN approval of the final agreement for the acquisition of the Offered Interests. If Buyer elects not to negotiate with ROFO Seller, or, after commencing negotiations, if Buyer determines that it will not purchase the Offered Interests, then, in either case, Buyer shall promptly notify Supplier thereof, and the ROFO Period shall terminate as of the date that any such notice is provided by Buyer.

6.1.2 In the event that: (a) Buyer does not elect to negotiate with ROFO Seller for the purchase of the Offered Interests pursuant to Section 6.1.1, or (b) negotiations commence pursuant to Section 6.1.1 but Buyer thereafter notifies Supplier that it has determined it will not purchase the Offered Interests, ROFO Seller may negotiate a Restricted Transaction with any other Person within one hundred eighty (180) days following ROFO Seller’s receipt of the Buyer ROFO Notice, subject, in all cases, to the terms and conditions of this Agreement, including Section 6.1.3 and the provisions of Article 23. Except as set forth in Section 6.6, in no event may ROFO Seller enter into a Restricted Transaction with any other Person on terms less favorable to ROFO Seller than such terms, if any, as were offered by Buyer during the ROFO Period. If definitive transaction documents between ROFO Seller and Buyer or its designee are not executed with respect to the Offered Interests within the ROFO Period, then the Parties will pursue the auction process set forth in Section 6.6.

6.1.3 Except as set forth in Section 6.6, if ROFO Seller and such other Person do not agree upon the terms, conditions and pricing for the Offered Interests by entering into definitive transaction documents within one hundred eighty (180) days following the expiration of the ROFO Period, ROFO Seller and any Offered Interests shall again be subject to this Section 6.1 with respect to any Restricted Transaction.

6.2 **Early Purchase Option.**

6.2.1 Supplier hereby grants to Buyer options to purchase the Facility ("**Early Purchase Option**") on a date chosen by Buyer during the six (6) months after the Facility’s 10th, 15th and 20th anniversaries of the Commercial Operation Date at the Fair Market Value, which option may be exercised by Buyer providing written notice to Supplier no less than one hundred and eighty (180) days before the applicable anniversary ("**Preliminary Interest Notice**").
6.2.2 Determination of Fair Market Value of the Facility. Promptly following delivery of a Preliminary Interest Notice, Buyer and Supplier shall mutually agree to the Fair Market Value of the Facility. If Buyer and Supplier cannot mutually agree to a Fair Market Value of the Facility within one (1) month of delivery of the Preliminary Interest Notice, then the Parties will pursue the auction process set forth in Section 6.6.

6.3 Purchase Option at the End of Term. Supplier hereby grants to Buyer the option to purchase the Facility at the end of the Term at the Fair Market Value (the “Final Purchase Option”), which option may be exercised by Buyer providing a notice to Supplier no less than one hundred and eighty (180) days prior to the end of the Term of Buyer’s election to exercise such option.

6.4 Efforts Required to Transfer Facility and Offered Interests. If Buyer exercises the Early Purchase Option, the Final Purchase Option or otherwise agrees to purchase the Facility pursuant to Section 6.1, then such purchase shall occur pursuant to a form of purchase and sale agreement which shall contain customary representations, warranties and covenants and otherwise be in form reasonably acceptable to the Parties. If the Parties are unable to reach agreement on the terms and conditions of the purchase and sale agreement within ninety (90) days after reaching mutual agreement on the Fair Market Value of the Facility, then the Parties will pursue the auction process set forth in Section 6.6. It shall be a condition of any such purchase that Buyer obtains all necessary Governmental Approvals and notwithstanding any language to the contrary in this Agreement Buyer shall be given sufficient time to obtain such approvals in accordance with applicable statutes and regulations. Pursuant to the purchase and sale agreement, Supplier will take all actions necessary to transfer by deed, bill of sale, or both, the Facility to Buyer, as well as all other improvements placed on the Project Site by Supplier that are required for the continued and uninterrupted use, maintenance and operation of the Facility, free and clear from any lien or monetary encumbrance created by or on behalf of Supplier or its Affiliates. In addition, Supplier will assign to Buyer all transferrable Governmental Approvals applicable to the Facility and Required Facility Documents, and all transferrable warranties for the Facility. Supplier shall cooperate with Buyer to assign and enforce any and all warranties that apply to the Facility or any of its component parts, which obligation shall survive the termination of this Agreement.

6.5 Due Diligence; Cooperation; Governmental Approvals; Notice of Rights. Supplier will provide in a timely manner, information regarding the Offered Interests which is reasonably requested by Buyer to allow Buyer to perform due diligence for the purchase of the Offered Interests pursuant to this Article 6. Supplier shall further provide commercially reasonable cooperation and assistance to Buyer, without further compensation, throughout Buyer’s efforts to properly account for and obtain any necessary Governmental Approvals with respect to the purchase of the Offered Interests pursuant to this Article 6. Notwithstanding anything in this Agreement or any definitive transaction documentation, Buyer shall not be obligated to proceed with the purchase of any Offered Interests pursuant to this Article 6 if Buyer does not receive all necessary Governmental Approvals in connection with such
transaction. Supplier shall put any Person with which it enters into discussions or negotiations regarding a Restricted Transaction on notice of the rights of Buyer set forth in this Article 6. Buyer shall be permitted to file a notice of the rights contained in this Article 6 with respect to the Project Site.

6.6 **Auction Process.** If Buyer and Supplier are unable to agree on both price and non-pricing terms and conditions of any proposed acquisition of the Facility or the equity interests in Supplier by Buyer pursuant to Sections 6.1-6.5, then within thirty (30) days after the failure to agree upon price and the terms of the definitive transaction documents pursuant to Section 6.1.2, the Fair Market Value pursuant to Sections 6.2.2 and 6.3, or the terms and conditions of the purchase and sale agreement pursuant to Section 6.4, as applicable, Supplier shall engage a nationally recognized investment advisor experienced in advising on the sale of assets similar to the Facility who shall commence a formal process for the sale of either the Facility or the equity interests in Supplier, at Supplier’s election. Buyer shall be permitted to participate in any such process on the same terms as all other bidders and as outlined in the process guidelines issued by Supplier. Supplier may select any party participating in such a process that is a Qualified Transferee as the purchaser of the Facility or the equity interests in Supplier and, notwithstanding anything to the contrary herein, Buyer shall have no further right of consent with regard thereto and shall cooperate with Supplier in consummation of the transactions with such Qualified Transferee. Notwithstanding any time limitations relating to any ROFO or any Purchase Option, Supplier shall have a period of nine (9) months from date of selection of the investment advisor in accordance with this Section 6.6 to sign a binding agreement with a Qualified Transferee for the sale of the Facility or the equity interests in Supplier, during which period Buyer shall have no other rights relating to the acquisition of the Facility or the equity interests in Supplier other than the right to participate in such process.

6.7 **Termination of Agreement.** Upon the acquisition of the Facility by Buyer pursuant to Section 6.4 or Section 6.6, this Agreement shall terminate and neither Party shall have any obligation to the other under this Agreement, except with respect to the terms and provisions hereof that expressly survive the termination of this Agreement.

7. **METERING, INVOICING AND PAYMENTS**

7.1 **Metering.**

7.1.1 **Meters.** Buyer shall, at Supplier’s cost, provide, install, own, operate and maintain all Meter(s) in good operating condition. The metering system design shall be subject to Buyer’s approval, which shall be consistent with Good Utility Practice, and shall be submitted to Buyer not later than Supplier’s completion of the Project Milestone in Section 2(B) of Exhibit 6. The meter system shall have Buyer specified equipment to connect with Buyer’s automated meter database, allowing for the DC-coupled nature of the Storage Facility. The Meters shall be used for quantity measurements under this Agreement. Such equipment shall be bi-directional, shall be
capable of measuring and reading instantaneous and hourly real and reactive energy and capacity and account for losses from the meter location to the Delivery Points or to the Storage Facility Metering Points. Supplier, at its expense, may install additional check meters. Supplier shall not install any check-metering equipment on or connected to Buyer-owned facilities including instrument transformers or metering circuitry wiring. Supplier shall, at its sole expense, install any additional or different Meters or related equipment necessary to comply with the requirements of Transmission Provider, any Electric System Authority or any Governmental Authority.

7.1.2 **WREGIS Metering.** Supplier shall cause, at its sole cost and expense, the Facility to implement all necessary generation information communications in WREGIS, and report generation information to WREGIS pursuant to one or more WREGIS-approved meters that are dedicated to the Facility and only the Facility. Supplier shall be responsible to obtain all qualified reporting entity services required by WREGIS at Supplier’s expense should Buyer not in its sole and absolute discretion provide them.

7.1.3 **Location.** Meters shall be installed at the location(s) specified in Exhibit 5, or as otherwise may be reasonably determined by Buyer and Supplier to effectuate this Agreement.

7.1.4 **Non-Interference.** Supplier shall not undertake any action that may interfere with the operation of the Meters. Supplier shall be liable for all costs, expense, and liability associated with any such interference with the Meters. Metering requirements shall apply such that there is no impact on the infrastructure and output associated with the Facility due to the presence of any other contiguous project.

7.1.5 **Meter Testing.** Meters shall be tested at least once every two (2) years by Buyer. Either Party may request a special test of Meters or check meters, but the requesting Party shall bear the cost of such testing unless there is an inaccuracy outside the limits established in American National Standard Institute Code for Electricity Metering (ANSI C12.1), latest version, or nationally approved equivalent (as available for DC meters), in which case the Party whose meters were found to be inaccurate (i.e. Buyer with respect to the Meters and Supplier with respect to check meters) shall be responsible for the costs of the special testing. Meters installed pursuant to this Agreement shall be sealed and the seal broken only when the meters are to be adjusted, inspected or tested. Authorized representatives of both Parties shall have the right to be present at all routine or special tests and to inspect any readings, testing, adjustment or calibration of the Meters or check meters. Buyer’s Operating Representative shall provide fifteen (15) Business Days prior notice of routine Meter testing to Supplier’s Operating Representative. If Supplier has installed check meters in accordance with Section 7.1.1, Supplier shall test and calibrate each such meter at least once every two (2) years. Supplier’s Operating Representative shall provide fifteen (15) Business Days prior notice of routine check meter testing to

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Buyer’s Operating Representative. In the event of special Meter testing, the Parties’ Operating Representatives shall notify each other with as much advance notice as practicable.

7.1.6 **Metering Accuracy.** If the Meters are registering but their accuracy is outside the limits established in ANSI C12.1 or nationally approved equivalent (as available for DC meters), Buyer shall repair and recalibrate or replace the Meters, and Buyer shall adjust payments to Supplier for the Delivered Amount for the lesser of the period in which the inaccuracy existed and ninety (90) days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the Meters; provided, however, that the adjustment period shall not exceed ninety (90) days. If adjusted payments are required, Buyer shall render a statement describing the adjustments to Supplier within thirty (30) days of the date on which the inaccuracy was rectified. Additional payments to Supplier by Buyer shall be made within thirty (30) days of receipt of Buyer’s statement. Any payments due Buyer pursuant to this Section 7.1.6 shall accompany Supplier’s next Billing Period statement.

7.1.7 **Failed Meters.** If the Meters fail to register, Buyer shall make payments to Supplier based upon Supplier’s check metering; provided, however, that if the accuracy of the check meters is subsequently determined to be outside the limits established in ANSI C12.1, Buyer shall adjust the payments to Supplier for the Delivered Amount calculated using the check meters for the lesser of the period in which the inaccuracy existed and ninety (90) days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the check meters; provided, however, that the adjustment period shall not exceed ninety (90) days. If no such metering is available, payments shall be based upon the Parties’ best estimate of the Delivered Amount. In such event, such payments made based upon the Parties’ estimate of the Delivered Amount shall be in full satisfaction of payments due hereunder. If the Parties cannot agree on a best estimate of the Delivered Amount the Dispute shall be resolved in accordance with Article 21.

7.1.8 **Weather Meter.** Supplier shall, at Supplier’s cost and no later than six (6) months prior to the Commercial Operation Date, provide, install, own, operate and maintain a device for the measurement of weather conditions relevant to the generation of Energy at the Project Site (the “Weather Meter”), provided that Supplier shall not select the type of Weather Meter without the prior written consent of Buyer, which shall not be unreasonably withheld. No later than twelve (12) months prior to the Commercial Operation Date, the Parties shall agree on the location of the Weather Meter and any applicable protocols for testing, accuracy, failure or other relevant characteristics of the Weather Meter.
7.2 Invoices.

7.2.1 Monthly Invoicing and Payment. On or before the 10th day of each month, Supplier shall send to Buyer an Invoice for the prior month (a “Billing Period”). Supplier shall calculate the Invoice based upon Meter data available to Supplier and as set forth in Exhibit 2B. Any correction or Dispute with respect to an Invoice is waived unless Buyer is notified within twelve (12) months, or Supplier is notified within thirty-six (36) months, after the Invoice is rendered or any specific adjustment to the Invoice is made. If an Invoice is not delivered to Buyer within twelve (12) months after the close of the Billing Period, the right to payment for such Billing Period is waived.

7.2.2 Replacement PC Invoice Calculation. In addition to the requirements for monthly Invoices set forth in this Section 7.2, if after the PC Administrator issues its final PC statement covering any Measurement Period and a PC Shortfall (as determined in accordance with Section 3.7.1) exists, Buyer shall send to Supplier an Invoice for such Measurement Period, which shall include the calculations set forth in Exhibit 2C.

7.2.3 Amounts Owing to Buyer. The Invoice referred to in Section 7.2.1 shall offset any amounts owing to Buyer with amounts owing to Supplier, and shall indicate the net payment due Supplier or Buyer, as applicable. Supplier shall provide supporting data in reasonable detail to support its calculations of any amounts owing to Buyer. Buyer may prepare and send to Supplier an Invoice for amounts owing to Buyer under this Agreement, and any such amounts will be payable to Buyer within ten (10) Business Days from Supplier’s receipt of such Invoice, subject to the terms and provisions of Section 7.2.5.

7.2.4 Method of Payment. Buyer or Supplier, as applicable, shall remit the payment of any undisputed amounts by wire or electronic fund transfer or otherwise pursuant to the instructions stated in Exhibit 4. Payment will be made on or before the later of the twentieth (20th) day following the end of each Billing Period (or the next following Business Day, if such twentieth (20th) day does not fall on a Business Day) or ten (10) Business Days from receipt of Invoice.

7.2.5 Examination and Correction of Invoices. As soon as practicable either Party shall notify the other Party in writing of any alleged error in an Invoice.

7.2.5.1 If a Party notifies the other Party of an alleged error in an Invoice, the Parties agree to use good faith efforts to reconcile the billing and mutually agree on the appropriate correction, if any.

7.2.5.2 If a correction is determined to be required, the invoicing Party shall provide an adjusted Invoice to the invoiced Party. If such error results in an additional payment to the invoicing Party, the
invoked Party shall pay such invoicing Party the amount of the adjusted Invoice within thirty (30) days of the date of receipt of the adjusted Invoice. If such error resulted in a refund owed to the invoiced Party, the invoicing Party shall pay the invoiced Party the amount of the adjusted Invoice within thirty (30) days of the date of receipt of the statement or at the invoiced Party’s option, the invoiced Party may net such amount against the subsequent monthly payment to the invoicing Party.

7.3 **Overdue Amounts and Refunds.** Overdue amounts and refunds of overpayments shall bear interest from and including, the due date or the date of overpayment, as the case may be, to the date of payment of such overdue amounts or refund at a rate calculated pursuant to 18 C.F.R. § 35.19a.

7.4 **Access to Books and Records.** Supplier agrees to make available for inspection upon five (5) Business Days written notice from Buyer its books and records as necessary for the purpose of allowing Buyer to verify the information contained within the invoices presented pursuant to Section 7.2.

7.5 **Parties’ Right to Offset.** Either Party shall have the right to offset any amounts owed to the other Party under this Agreement including amounts owed by Supplier to Buyer for Standby Service.

7.6 **Taxes.** Buyer is responsible for any Taxes imposed on or associated with the Energy or Discharging Energy or its delivery from and after the Delivery Points. Supplier is responsible for any Taxes imposed on or associated with the Energy or Discharging Energy or its delivery up to or at the Delivery Points. Either Party, upon written request of the other Party, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if such Party is exempt from Taxes, and shall use reasonable efforts to obtain and cooperate with the other Party in obtaining any exemption from or reduction of any Tax. Each Party shall hold harmless the other Party in accordance with Article 18 from and against Taxes imposed on the other Party as a result of such Party’s actions or inactions in contravention of this Section 7.6.

8. **FACILITY CONSTRUCTION; OPERATIONS AND MODIFICATIONS**

8.1 **Construction of Facility.** Supplier shall construct or cause the Facility to be constructed in accordance with Good Utility Practices and the Project Milestones and to ensure that: (a) Supplier is capable of meeting its supply and delivery obligations with respect to Product over the Term; (b) the Facility is consistent with the technical specifications set forth in Exhibit 11; (c) subject to Section 3.5, the Generating Facility is at all times considered a Renewable Energy System; and (d) subject to Section 3.5, the Generating Facility is at all times in compliance with all requirements imposed on Renewable Energy Systems as set forth in the applicable Renewable Energy Law. Supplier shall deliver to Buyer an ALTA Survey of the Project Site within ten (10) days of such survey becoming available to Supplier, but in no event later than the issuance of the Notice to Proceed in accordance with Exhibit 6. Supplier shall provide to Buyer in a form satisfactory to Buyer: (y) not
later than the Project Milestone described in Section 2(B) of Exhibit 6, a completed version of Exhibit 14; and (z) within thirty (30) days after the Commercial Operation Date, a revised version of Exhibit 14 reflecting the Facility as built. Supplier shall provide Buyer with copies of the Construction Contract promptly after its execution and any documentation and drawings reasonably requested by Buyer, redacted of any pricing or other proprietary information and any other information Supplier is not permitted to disclose pursuant to a confidentiality agreement, provided that Supplier shall use commercially reasonable efforts to secure in the Construction Contract the ability to disclose the terms of the Construction Contract other than pricing information. The Parties acknowledge and agree that the Shared Facilities may be subject to certain shared facilities or co-tenancy agreements to be entered into among Supplier, Supplier’s Affiliates, or third parties pursuant to which certain Shared Facilities may be subject to joint ownership and shared maintenance and operation arrangements; provided that such agreements (i) shall permit Supplier to perform or satisfy, and shall not purport to limit, its obligations hereunder and (ii) provide for separate metering of the Facility.

### 8.2 Performance of Project Milestones

Supplier shall complete each Project Milestone specified in Exhibit 6 on or before 16:00 hours PPT on the date specified for each Project Milestone listed in Exhibit 6.

#### 8.2.1 Completion of Project Milestones

Upon Supplier’s completion of each Project Milestone, Supplier shall provide to Buyer in writing, pursuant to Section 29.1, documentation as specified in Exhibit 6 and reasonably satisfactory to Buyer demonstrating such Project Milestone completion. Such documentation shall be provided within thirty (30) days of such completion but, if it is provided later than the date specified for such Project Milestone listed in Exhibit 6, Seller shall also provide the information described below and, if the Project Milestone is a Critical Project Milestone, pay liquidated damages as provided below. Buyer shall acknowledge receipt of the documentation provided under this Section 8.2.1 and shall provide Supplier with written acceptance or denial of each Project Milestone within fifteen (15) Business Days of receipt of the documentation. If Buyer does not acknowledge receipt or provide written acceptance or denial of any Project Milestone within fifteen (15) Business Days, then such Project Milestone will be deemed to occur on the date that such documentation was provided to Buyer. Failure of Supplier to achieve a Critical Project Milestone on or before the scheduled date (or, in the case of the Commercial Operation Deadline, after expiration of the applicable period for which Daily Delay Damages are owed by Supplier pursuant to Section 8.5.1), will constitute an Event of Default as provided in Article 24.

If any Project Milestone (other than a Critical Project Milestone) is not completed on or before the date specified in Exhibit 6, Supplier will (i) inform Buyer of a revised projected date for the occurrence or completion of such Project Milestone (which will be deemed the new deadline for such Project Milestone), and any impact on the timing of the Commercial Operation Date (and on any other Project Milestone) and (ii) provide Buyer with a written report containing Supplier’s analysis of the reasons behind
the failure to meet the original Project Milestone deadline and whether remedial actions are necessary or appropriate, and describing any remedial actions that Supplier intends to undertake to ensure the timely achievement of the Commercial Operation Date. Provided that Supplier complies with the preceding sentence, no failure of Supplier to achieve a Project Milestone (other than a Critical Project Milestone) on or before the scheduled date will constitute an Event of Default.

8.2.2 Progress Towards Completion. Supplier shall notify Buyer’s Contract Representatives promptly (and in any event within ten (10) Business Days) following its becoming aware of information that leads to a reasonable conclusion that a Project Milestone will not be met, and shall convene a meeting with Buyer to discuss the situation not later than fifteen (15) Business Days after becoming aware of this information.

8.2.3 Interconnection Study. Supplier has submitted an interconnection request to the Transmission Provider requesting to increase the interconnection capacity available under the 230 kV IA, to allow the entire Facility to be interconnected at 230 kV through a single point of interconnection pursuant to the 230 kV IA. Promptly after receiving a system impact study report from the Transmission Provider for this interconnection request, Supplier shall provide a copy of the report to Buyer. If the estimated cost of network upgrades assigned to Supplier in the system impact study report for this interconnection request are less than five million seven hundred thousand dollars ($5,700,000), then (a) the definition of “IA” will be revised to refer only to the 230 kV IA, (b) the references to “Delivery Points” throughout this Agreement will be revised to refer to a single 230 kV Delivery Point, and (c) Supplier will provide revised versions of Exhibits 1, 3A, 3B, and 5, which will supersede the then existing Exhibits 1, 3A, 3B, and 5.

8.3 Commercial Operation Date.

8.3.1 Notice of Testing. Supplier shall notify Buyer’s Contract Representatives at least ten (10) Business Days prior to the commencement of any performance tests required by the Construction Contract, including any performance tests required by Exhibit 7. Buyer shall have the right to witness all tests or have Buyer’s representatives witness all tests. The presence of Buyer or a Buyer representative shall not be construed as an obligation on Buyer’s part to design, conduct, monitor or endorse any test results or as a ratification or acceptance thereof. Buyer shall be deemed to waive its right to be present at the performance tests if Buyer fails to appear at the scheduled time for the performance tests.

8.3.2 Certifications. Within five (5) Business Days of the successful completion of the performance tests pursuant to Exhibit 7, Supplier shall provide Buyer with written notice stating when Supplier believes that the Facility has
achieved Commercial Operation, including the following written certifications.

8.3.2.1 A certification by a duly authorized officer of Supplier stating the following:

"I, [Name], in my capacity as the duly appointed [Title] of [Supplier] ("Supplier") hereby certify, on behalf of Supplier that: (a) the Facility has been constructed in accordance with Good Utility Practice and the Generating Facility has delivered Energy to and at the Delivery Points and Charging Energy to the Storage Facility Metering Points; (b) all of the requirements set forth in Sections 8.1, 8.3 and 17.2, and Exhibits 6 and 7 of the Long-Term Renewable Power Purchase Agreement between Supplier and Buyer dated [_______], ("Agreement") have been satisfied; (c) I am authorized to act on behalf of and bind Supplier with respect to this certificate; (d) Supplier has received the Supplier Required Regulatory Approvals listed in Exhibit 10 and has entered into or obtained all Required Facility Documents as listed in Exhibit 12, true, correct and complete copies of which are attached (other than confidential or commercial terms which have been redacted); and (e) Supplier acknowledges that Buyer is relying on this certification in connection with carrying out its obligations under the Agreement and Supplier will indemnify Buyer for any inaccuracy related to this certification; and (f) the Storage Facility is fully capable of charging, storing and discharging energy up to the Storage Contract Capacity."

8.3.2.2 A certificate addressed to Buyer from a Licensed Professional Engineer confirming: (1) the nameplate capacity rating of the Generating Facility at the anticipated time of Commercial Operation in MW AC ("Certified Nameplate Capacity Rating") and (2) that the Facility is able to generate and deliver electric power reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof, including the Storage Operating Procedures; and, (3) performance tests required by Exhibit 7 have been successfully completed; and (4) that the Storage Facility is able to charge, store and discharge energy reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof, including the Storage Operating Procedures. The Certified Nameplate Capacity Rating must not be less than six hundred twenty-one (621) MW.

8.3.2.3 A certificate addressed to Buyer from a Licensed Professional Engineer stating that, all required interconnection tests have been completed and the Facility is physically interconnected
with the Transmission System and able to deliver Net Energy consistent with the terms of this Agreement.

8.3.2.4 An opinion from an attorney licensed in the state of Nevada that is not an employee of Supplier (or any Affiliate) and has no financial interest in the Facility addressed to Buyer stating that Supplier has received the Supplier Required Regulatory Approvals listed in Exhibit 10 and has entered into or obtained all Required Facility Documents as listed in Exhibit 12, and attaching copies of the Supplier Required Regulatory Approvals listed in Exhibit 10 and all Required Facility Documents listed in Exhibit 12, provided, however, that Supplier may redact or omit confidential or commercial terms from such documents. The opinion shall further state that the real estate rights obtained by Supplier with respect to the Project Site are adequate in all respects for the ownership, operation, access to and maintenance of the Facility as of the date of the opinion.

8.3.3 Dispute of Commercial Operation. Buyer will have fifteen (15) Business Days after receipt of the certifications required by this Section 8.3 in which to Dispute the Commercial Operation Date by written notice to Supplier. In the event of such a Dispute, Buyer and Supplier will attempt in good faith to resolve the Dispute. If the Parties are unable to resolve the Dispute within fifteen (15) Business Days’ after Buyer’s notice of Dispute, then either Party may seek resolution of the Dispute in accordance with Article 21. Notwithstanding the foregoing, Buyer’s failure to Dispute the certification will in no way affect its rights to indemnification for any inaccuracy related to the certification, including overpayments that may be paid by Buyer due to such inaccurate certification.

8.4 Failure to Achieve Commercial Operation.

8.4.1 In the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline and Supplier fails to promptly pay Daily Delay Damages as provided in Section 8.5.1, Buyer may elect to terminate this Agreement and, Supplier shall pay to Buyer, and Buyer shall be entitled to collect or retain, as applicable, the full Development Security amount as liquidated damages for Supplier’s failure to meet its obligations prior to the Commercial Operation Deadline. Upon Buyer’s collection of the full Development Security amount from Supplier (or from security provided on Supplier’s behalf), this Agreement will be terminated, and neither Party will have any further obligations under this Agreement, including under Section 8.5, except those obligations expressly provided to survive termination pursuant to Section 2.4. The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder prior to the Commercial Operation Deadline, and, accordingly, the Parties agree that retention by Buyer of the full Development Security is reasonable as
liquidated damages, and is not a penalty, and except as provided otherwise in this Agreement, shall constitute Buyer's sole and exclusive remedy in the event that the Agreement is terminated pursuant to this Section 8.4.1.

8.4.2 The provisions of this Section 8.4 are in addition to, and not in lieu of, any of Buyer's rights or remedies under this Agreement, including Article 24, for Events of Default other than the failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5 Delay Damages.

8.5.1 In the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline, then for each day up to, but not exceeding, one hundred and eighty (180) days, that Supplier fails to achieve Commercial Operation, Supplier shall be obligated to pay to Buyer liquidated damages equal to Daily Delay Damages. If Daily Delay Damages have been accumulated for one hundred and eighty (180) days and Commercial Operation has not been achieved, Buyer may terminate this Agreement. Supplier shall pay any amounts owed to Buyer under this Section 8.5 in the Billing Periods immediately succeeding the Billing Period during which Supplier's obligation to pay such amounts arose.

8.5.2 In addition to amounts payable pursuant to Section 8.5.1, Supplier shall be liable, in accordance with Section 18.1, for any Regulatory Penalties incurred or suffered by Buyer as a result of Supplier's failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5.3 The provisions of this Section 8.5 are in addition to, and not in lieu of, any of Buyer's rights or remedies under Article 24 for Events of Default other than the failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5.4 The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder prior to the Commercial Operation Deadline, and, accordingly, the Parties agree that payment by Supplier of Daily Delay Damages is reasonable as liquidated damages, and is not a penalty.

8.6 Nameplate Damages.

8.6.1 If the Certified Nameplate Capacity Rating is less than the Expected Nameplate Capacity Rating, Supplier shall provide Buyer a onetime payment in an amount equal to (a) subtracting (i) Certified Nameplate Capacity Rating from (ii) the Expected Nameplate Capacity Rating in MW, multiplied by (b) Deficit Damages Rate per MW of difference ("Deficit Damages"), provided that in no event shall the Certified Nameplate
Capacity Rating be less than six hundred twenty-one (621) MW. Supplier’s
total liability for Deficit Damages shall not exceed thirteen million eight
hundred thousand dollars ($13,800,000). Deficit Damages, if any, shall be
paid to Buyer within five (5) Business Days of Buyer’s receipt of the
certification required in Section 8.3.2.2. Upon payment of Deficit Damages: (i)
Exhibit 1 shall be revised to reflect the Certified Nameplate Capacity Rating;
and (ii) the Dispatch Availability Amount, the Maximum Amount and the Yearly PC Amount shall each be adjusted by the ratio of
the Certified Nameplate Capacity Rating to the Expected Nameplate Capacity Rating, and Exhibits 13 and 18 shall be revised accordingly.

8.6.2 If the Certified Nameplate Capacity Rating is greater than the Expected Nameplate Capacity Rating by greater than two percent (2%), Supplier
shall pay Buyer a onetime payment in an amount equal to one half of the
Development Security, paid to Buyer within five (5) Business Days of
Buyer’s receipt of the certification required in Section 8.3.2.2. If Supplier
fails to make such payment in a timely manner, Buyer may retain such
amount from the Development Security or Operating Security. Supplier
shall take all necessary actions, including but not limited to software or
hardware solutions, to limit the Certified Nameplate Capacity Rating to the
Expected Nameplate Capacity Rating.

8.6.3 If the tested Storage Contract Capacity as of the Commercial Operation
Date is more than three percent (3%) below three hundred eighty (380)
MW, Supplier shall provide Buyer, as Buyer’s sole remedy for such
shortfall, a onetime payment in an amount equal to (a) subtracting (i) the
tested Storage Contract Capacity from (ii) three hundred sixty-eight and
six-tenths (368.6) MW, multiplied by (b) Storage Deficit Damages Rate per
MW of difference (“Storage Deficit Damages”), provided that in no event
shall the Storage Contract Capacity be less than three hundred sixty (360)
MW. Supplier’s total liability for Storage Deficit Damages shall not exceed
five million, one hundred sixty thousand dollars ($5,160,000). Storage
Deficit Damages, if any, shall be paid to Buyer within five (5) Business
Days after the Commercial Operation Date. Upon payment of Deficit
Damages, Exhibit 1 shall be revised to reflect the tested Storage Contract
Capacity as deemed appropriate by an independent, licensed engineer for
the purpose of all relevant calculations hereunder.

8.7 Modification. Except as otherwise permitted in this Agreement, Supplier shall not
be permitted to make any modification to the Generating Facility without the prior
written consent of the Buyer which may be withheld in Buyer’s sole discretion.
The above shall not prevent Supplier from performing maintenance and repairs to
the Generating Facility so long as such maintenance and repairs do not alter the
Generating Facility as defined. In addition, Supplier shall be permitted, without
Buyer’s prior consent, to make any change (a) in electrical inverters, subject to
approval in the Interconnection Process, as set forth in Section 25.6; (b) any
change to the number, sizing, type, chemical composition, or efficiency of the
photovoltaic modules; (c) any change with respect to Storage Facility battery
chemistry so long as the battery chemistry remains within the lithium-ion category; and (d) subject to Supplier’s compliance with Section 25.14, if applicable, any change with respect to equipment suppliers for the Facility; provided, however, that such changes may not increase any of the parameters set forth in Exhibit 1 by more than one percent (1%) without Buyer’s prior written consent except for Section 9(e) of Exhibit 1. Any modifications requiring Buyer’s consent and for which Buyer has provided written consent shall be conducted in accordance with Good Utility Practice and all applicable Laws and reliability criteria, as such may be amended from time to time, and the requirements of Article 11. If Supplier makes a modification to the Facility that requires Buyer’s consent under this Section 8.7 and is not approved by Buyer, Buyer shall be entitled to receive in addition to any other remedy available to Buyer as liquidated damages the full amount of the Development Security or Operating Security, as applicable. The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder, and, accordingly, the Parties agree that payment by Supplier of Development Security or Operating Security, as applicable, is reasonable as liquidated damages, and is not a penalty.

8.8 **Operation and Maintenance.** Subject to Section 3.5, Supplier, at all times shall install, operate, maintain and repair the Facility in accordance with Good Utility Practice and applicable Laws and to ensure: (a) Supplier is capable of meeting its supply obligations over the Term; (b) the Generating Facility is at all times a Renewable Energy System; and (c) Supplier is at all times in compliance with all requirements of a renewable energy generator set forth in the Renewable Energy Law. Supplier shall (x) maintain records of all operations of the Facility in accordance with Good Utility Practice, and (y) follow all regulations, directions and procedures of Buyer, Transmission Provider, any Electric System Authority and any other Governmental Authority to protect and prevent the Transmission System from experiencing any negative impacts resulting from the operation of the Facility. In the event of an inconsistency between any applicable procedures, Buyer may direct which procedures shall govern (or barring direction from Buyer, the more stringent procedure shall govern). Supplier shall use all reasonable efforts to avoid any interference with Buyer’s operations. Supplier shall cause the Energy to meet the Power Quality Standards at all times, and shall operate the Facility consistent with WECC, NERC, Buyer, Electric System Authority, Governmental Authority and Transmission Provider requirements. Prior to the beginning of the Term, the Parties shall mutually develop written procedures governing operations of the Storage Facility, not in contravention or amendment of any right or obligation set forth herein, including (a) minimum and maximum operating parameters; (b) procedures for scheduling and dispatch, (c) methods of day-to-day communications, (d) key personnel lists, (e) recordkeeping and (f) such other procedures and protocols as the Parties deem appropriate for implementation of this Agreement (the “Storage Operating Procedures”); provided that failure to agree on such procedures shall not relieve either of the Parties of its obligations under this Agreement. The Storage Operating Procedures are provided in Exhibit 24.
8.9 **Operation and Maintenance Agreement.** No later than one hundred eighty (180) days prior to the Commercial Operation Date, if Supplier intends to subcontract any aspect of the operation of the Facility, Supplier shall provide a copy of any proposed agreement between Supplier and such sub-operator which requires the sub-operator to operate the Facility in accordance with the terms hereof which shall be attached to this Agreement as Exhibit 15. Supplier shall also provide a certified copy of a certificate warranting that the sub-operator is a corporation, limited liability company or partnership in good standing with the State in which the Facility is located, which shall be attached to this Agreement as part of Exhibit 15. Buyer shall have fifteen (15) days in which to notify Supplier of its objection to any proposed sub-operator that is not a Qualified Operator, in which case Supplier shall not subcontract with such proposed sub-operator.

8.10 **Right to Review.** Buyer shall have the right to review during normal business hours the relevant books and records of Supplier to confirm the accuracy of anything relating to this Agreement. Buyer is under no obligation to exercise any of these review rights. Buyer shall have no liability to Supplier for failing to advise it of any condition, damages, circumstances, infraction, fact, act, omission or disclosure discovered or not discovered by Buyer with respect to the Facility or this Agreement.

8.11 **Undertaking of Agreement; Professionals and Experts.** Supplier has engaged those professionals or other experts it believes necessary to understand its rights and obligations pursuant to this Agreement. All professionals or experts, including engineers, attorneys or accountants, that Supplier may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Supplier. In entering into this Agreement and the undertaking by Supplier of the obligations set forth herein, Supplier has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Buyer in connection with the transactions contemplated by this Agreement.

9. **EMERGENCY**

9.1 **Compliance.** Supplier shall promptly comply with any applicable requirements of any Electric System Authority, Governmental Authority, Transmission Provider, transmission operator or their successors, regarding the reduced or increased production of the Facility or otherwise in the event of any Emergency.

9.2 **Notification.** Supplier shall provide prompt oral and written notification to Buyer of any Emergency, including a description in reasonable detail of the Emergency and any actions undertaken to prevent, avoid or mitigate Loss therefrom or to expedite the restoration of service.

9.3 **Due Care.** In the event of an Emergency, Supplier shall take all reasonable actions to prevent, avoid or mitigate Loss therefrom or to expedite the restoration of service; provided, however, that Supplier shall give Buyer prior notice, if
practicable, before taking any action. This Section 9.3 shall not be construed to supersede Sections 9.1 and 9.2.

9.4 **Not Excused Product.** An Emergency declared by Supplier with respect to the Facility will not result in any Excused Product except to the extent the Emergency qualifies as an event of Force Majeure.

9.5 **No Buyer Liability.** Notwithstanding any provision to the contrary contained in this Agreement, Buyer shall have no obligation to pay Supplier in respect of any Product Supplier is unable to deliver or Buyer is unable to receive in accordance with the requirements of this Agreement due to an Emergency or Force Majeure.

### 10. CURTAILMENT & DISPATCHABILITY

10.1 **Transmission Provider Instructions.** Supplier shall obey all Transmission Provider Instructions for curtailment of Energy by the Transmission Provider or orders for curtailment of Energy by any Electric System Authority. For any period of curtailment described in this Section 10.1 that occurs during the Dispatch Availability Months, if the Storage Facility is capable of accepting Charging Energy during such period, then Buyer’s Charging Notice will be automatically deemed revised to allow Net Energy that would have been delivered to the Delivery Points absent such curtailment to be delivered, to the maximum extent feasible in accordance with the Storage Operating Procedures, to the Storage Facility Metering Points as Buyer’s Charging Energy instead.

10.1.1 **Curtailments.** Without limiting Section 10.1, Buyer shall not be obligated to purchase, receive, pay for, or pay any damages associated with, or incur any liability with respect to, compliance or curtailment of Energy by Supplier made in response to any orders for curtailment provided for in Section 10.1, including in respect of Net Energy (or associated Renewable Energy Benefits) not delivered to the Delivery Points due to any of the following: (a) the interconnection between the Facility and the Transmission System is disconnected, suspended or interrupted, in whole or in part; (b) the Transmission Provider, Electric System Authority or Market Operator (other than for economic reasons due to scheduling, such economically curtailed amounts being Un-Dispatched Amounts if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full Requirements Period) directs a general curtailment, reduction or re-dispatch of generation in the area (which would include the Net Energy), for any reason, even if such curtailment, reduction or re-dispatch directive is carried out by Buyer; (c) if Buyer curtails or otherwise reduces the Net Energy in order to meet its obligations to the Transmission Provider, Electric System Authority or Market Operator (other than for economic reasons due to scheduling, such economically curtailed amounts being Un-Dispatched Amounts if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full Requirements Period) to operate within system limitations; (d) the Facility’s Energy is not received because the Facility is not fully integrated.
or synchronized with the Transmission System; or (e) an event of Force Majeure prevents either Party from delivering or receiving Net Energy ("Curtailed Product").

10.1.2 **Curtailed Product Verification.** Supplier shall promptly calculate, based on the Availability Backcast Amount plus any curtailed Discharging Energy during the Full Requirements Period, and provide Buyer with such information and data as Buyer may request to confirm, the amount of the Curtailed Product that was not generated as a result of the curtailment. During any such period of curtailment, Supplier shall not deliver Net Energy to the Delivery Points (to the extent curtailed by Transmission Provider) or sell Product to any third party. Curtailed Product shall constitute Excused Product for purposes of calculating a Shortfall or PC Shortfall. Under no circumstance shall the provisions of this Section 10.1.2 apply to a curtailment of the Facility based upon an Emergency with respect to the Facility.

10.2 **Dispatchability.**

10.2.1 Buyer is permitted to schedule Energy deliveries in accordance with Article 14 during any Dispatchable Period.

10.2.2 Except as expressly provided in this Agreement, Supplier shall comply with the schedules provided by Buyer during the Dispatchable Period. For any period during the Dispatchable Period, the "Un-Dispatched Amount" is the Availability Backcast Amount minus the Delivered Amount minus an amount equal to the Excused Product described in Sections 3.6.6(a) through (f) and (h). During the Dispatchable Period, Supplier shall produce Energy solely in accordance with Buyer’s schedule (except as otherwise expressly provided herein) and Supplier shall not sell Product to any third party that was not scheduled by Buyer.

10.3 **Network Resource Designation.** Within sixty (60) days after the Effective Date, Buyer will submit an application to Transmission Provider to designate the Facility as a Network Resource. Supplier will provide all information related to the Facility required for such application within thirty (30) days after the Effective Date. Buyer will provide a copy of such application to Supplier.

11. PLANNED OUTAGES

11.1 **Approvals.** Supplier shall request and obtain Buyer’s prior written approval, which approval shall not be unreasonably withheld, before conducting any non-forced outage of the Facility or reducing the capability of the Generating Facility to deliver Energy or the Storage Facility to receive Buyer’s Charging Energy or deliver Discharging Energy (each such reduction or outage, a "Planned Outage") so as to minimize the impact on the availability of the Facility. Supplier shall only schedule Planned Outages during the months of January, February, March, April, October,
November and December, unless otherwise approved by Buyer, and as may be otherwise restricted by Law.

11.2 Schedules. Planned Outages will be scheduled and conducted in accordance with the following:

11.2.1 Within ninety (90) days prior to the Commercial Operation Date and on or before October 1 of each Contract Year, Supplier shall provide Buyer with a schedule of proposed Planned Outages for the remainder of the year or upcoming Contract Year, as applicable. The proposed schedule will designate the Delivery Hours and amount (in MWh) in which the Energy will be reduced in whole or in part by the proposed Planned Outages. Each proposed schedule shall include all applicable information, including the following: the month, day and Delivery Hour each requested outage will begin and conclude, the facilities impacted, the purpose of the requested outage, and any other relevant information. The total combined Delivery Hours of: (i) Planned Outages and (ii) unplanned outages of the Storage Facility for the months of January through April and October through December, in any Contract Year (based on the Dispatch Availability Amounts for such Delivery Hours) shall not exceed four percent (4%) of the total annual Dispatch Availability Amounts for all hours in the applicable Contract Year (prorated for the Stub Period, if any) unless otherwise approved by Buyer.

11.2.2 Buyer shall promptly review Supplier’s proposed schedule of Planned Outages and either require modifications or approve the proposed schedule within thirty (30) days of Buyer’s receipt of such schedule. If Buyer requires modifications to the proposed schedule, then Supplier shall promptly circulate a revised schedule of Planned Outages to Buyer consistent with Buyer’s requested modifications. Under no circumstances will Supplier schedule Planned Outages to occur during May, June, July, August or September. Product not delivered to Buyer during periods of Planned Outages, up to the MWh specified, (a) will comprise Excused Product to the extent such Planned Outages are conducted in accordance with the Planned Outage schedule approved by Buyer in accordance with this Article 11, and (b) will not comprise Excused Product to the extent any outage period or MWh exceed that set forth in the Planned Outage schedule approved by Buyer in accordance with this Article 11, or the Planned Outage is not approved by Buyer. Supplier shall make reasonable efforts to accommodate any proposed revisions by Buyer to the approved Planned Outage schedule.

11.2.3 Regardless of approval of a Planned Outage, Supplier shall not start a Planned Outage on the Facility without confirming the approved Planned Outage with Buyer’s Operating Representative five (5) Business Days prior to the start of such Planned Outage.
11.2.4 If following a notice pursuant to Section 11.2.3, Buyer requests that Supplier not undertake an approved Planned Outage as scheduled, for reasons other than Force Majeure, Transmission Provider Instructions or Emergency, then Supplier may promptly deliver to Buyer a written reasonable estimate of the costs expected to be incurred as a result of Supplier not undertaking the Planned Outage as scheduled. If Buyer agrees to the estimated costs, then Supplier shall not undertake the Planned Outage, and Buyer shall reimburse Supplier for its documented out-of-pocket costs actually incurred by Supplier in connection with not undertaking such Planned Outage (not to exceed the written estimated costs prepared by Supplier and delivered to Buyer). Any Planned Outage that is not instituted pursuant to this Section 11.2.4 will be rescheduled to occur in the same Contract Year in which it was originally scheduled, in accordance with Section 11.2.2.

12. REPORTS; OPERATIONAL LOG

12.1 Copies of Communications. Supplier shall promptly provide Buyer with copies of any orders, decrees, letters or other written communications to or from any Governmental Authority asserting or indicating any violation of Laws which relate to Supplier or construction, operation or maintenance of the Facility. Supplier shall keep Buyer apprised of the status of any such matters.

12.2 Notification of Facility Regulatory Status. Supplier shall notify Buyer of the regulatory status of the Facility as an EWG or QF no later than ninety (90) days prior to the Operation Date, and will provide Buyer with evidence documenting receipt of the required Governmental Approvals related to such designation (as such approvals are set forth in Exhibit 10). Following the Operation Date, Supplier shall notify Buyer, as soon as practicable, of any changes in regulatory status of the Facility, and will provide Buyer with evidence documenting receipt of the required Governmental Approvals related to such changed regulatory status (as such approvals are set forth in Exhibit 10) and reasonable support data requested by Buyer.

12.3 Notices of Change in Facility. In addition to any consent required pursuant to Section 8.7, Supplier shall provide notice to Buyer as soon as practicable to any temporary or permanent change to the performance, operating characteristics, or major generation components (such as generators, inverters, solar panels or similar equipment, as applicable) of the Facility. Such notice shall describe any changes, expected or otherwise, to the Expected Nameplate Capacity Rating, generating capability, the rate of production and delivery of Net Energy, Discharging Energy and other Product, interconnection and transmission issues, and any additional information requested by Buyer.

12.4 Project Reports and Project Review Meetings.

12.4.1 Prior to the Commercial Operation Date. Prior to the Commercial Operation Date, Supplier shall provide to Buyer a monthly project report, which shall
include the following: status in obtaining Project Milestones, including level one schedule; progress in obtaining any Governmental Approvals in connection with achieving the Commercial Operation Date; and a discussion of any foreseeable disruptions or delays. The monthly project reports will be provided to Buyer no later than ten (10) Business Days after expiration of the previous month. The Parties shall conduct meetings every six (6) months (or more frequently if requested by Buyer) to review this data and any information related to Supplier’s completion of or progress toward the Project Milestone activities listed in Exhibit 6. In addition to any other requirements for Commercial Operation under this Agreement, Supplier shall: (a) provide notice to Buyer of its best estimate of the projected Operation Date and Commercial Operation Date; (b) notify Buyer as soon as Supplier becomes aware of any changes in such projected dates; and (c) coordinate with Buyer regarding the commencement of operation of the Facility. In addition to the foregoing, Supplier will provide Buyer with such other operational or technical data as Buyer may reasonably request and as may be reasonably necessary to determine Supplier’s compliance with its obligations hereunder and its progress toward Commercial Operation.

12.4.2 After Commercial Operation Date. After the Commercial Operation Date, Supplier shall provide to Buyer within thirty (30) days of the end of each quarter throughout the Term, in electronic format, a report which shall include all pertinent information in connection with the Facility, including: (a) all weather data from any collection device measuring data with respect to the Facility (such as a met tower or similar measurement device); (b) any available site condition reports; (c) all reporting information maintained in the operational log and any other SCADA data from the Facility; and (d) any reports pertaining to the Facility resource and such other data and reports as may be reasonably requested by Buyer and which should be maintained by Supplier in accordance with Good Utility Practice for the relevant technology. In addition, Supplier shall provide remote access to Buyer for the Facility’s operations and maintenance data for purposes of Buyer integrating such data into Buyer’s Monitoring & Diagnostics center.

12.4.3 Operations Log. Supplier shall maintain in accordance with Good Utility Practice an operations log, which shall include: (a) all Planned Outages and unplanned outages, alarms, circuit breaker trip operations, partial deratings of equipment, mechanical impairments defects or unavailability with respect to generating equipment; (b) the cause (including any root cause analysis undertaken) and remediation undertaken by Supplier with respect to the events listed in (a); (c) the Delivered Amounts for the Stub Period and each Contract Year; and (d) any other significant event or information related to the operation of the Facility or the delivery of Net Energy or other Product. The operations logs shall be available for inspection by Buyer upon two (2) Business Days’ notice together with all data maintained by Supplier as support for such logs. Supplier shall be responsible for maintaining
sufficient evidentiary support in order to document the information contained in such operation logs.

12.5 **Financial Information.** Within thirty (30) days of Buyer’s written request, Supplier shall provide Buyer with copies of Supplier’s most recent quarterly and annual unaudited financial statements, which financial statements shall be prepared in accordance with generally accepted accounting principles.

12.6 **Information to Governmental Authorities.** Supplier shall, promptly upon written request from Buyer, provide Buyer with data collected by Supplier related to the construction, operation and maintenance of the Facility reasonably required by Buyer or an Affiliate thereof for reports to, and information requests from, any Governmental Authority, or any intervenor or party in any rate case or regulatory proceeding of Buyer or an Affiliate thereof. In addition, Supplier shall provide to Buyer copies of all submittals to a Governmental Authority directed by Buyer and related to the operation of the Facility with a certificate that the contents of the submittals are true and accurate to the best of Supplier’s knowledge after due inquiry. Supplier shall use commercially reasonable efforts to provide this information to Buyer with sufficient advance notice to enable Buyer to review such information and meet any submission deadlines imposed by the requesting Governmental Authority.

12.7 **Accounting Standards.** If Buyer or one of its Affiliates determines that it may hold a variable interest in Supplier under the Accounting Standards Codification (“ASC”) 810, Consolidation of Variable Interest Entities, or requirements of Law, but it lacks the information necessary to make a definitive conclusion, Supplier hereby agrees to provide, upon Buyer’s written request, sufficient financial and ownership information so that Buyer or its Affiliate may confirm whether a variable interest does exist under ASC 810 or requirements of Law. If Buyer or its Affiliate determines that, it holds such a variable interest in Supplier, Supplier hereby agrees to provide, upon Buyer’s written request, sufficient financial and other information to Buyer or its Affiliate so that Buyer may properly consolidate the entity in which it holds the variable interest or present the disclosures required by ASC 810 or applicable Law. Supplier shall have the right to seek confidential treatment of any such information from any Governmental Authority entitled to receive such information. Information provided pursuant to this Section 12.7 is subject to Buyer’s rights to disclose such information pursuant to this Agreement and pursuant to any applicable requirements of Law.

12.8 **Documents to Governmental Authorities.** Supplier shall promptly provide to Buyer a copy of any statement, application, and report or any document with any Governmental Authority relating to operation and maintenance of the Facility.

12.9 **Environmental Information.** Supplier shall, promptly upon written request from Buyer, provide Buyer with all data reasonably requested by Buyer relating to environmental information under any Required Facility Document listed in Exhibit 12 or otherwise in effect with respect to the Facility. Supplier shall further provide Buyer with information relating to environmental impact mitigation measures it is
taking in connection with the Facility’s construction or operation that are required by any Governmental Authority. As soon as it is known to Supplier, Supplier shall disclose to Buyer, the extent of any actual or alleged violation of any Environmental Laws arising out of the construction or operation of the Facility, or the actual or alleged presence of Environmental Contamination at the Facility or on the Project Site, or occurrence of any enforcement, legal or regulatory action or proceeding relating to the foregoing.

13. COMMUNICATIONS

13.1 Supplier’s Operating Representative. Supplier’s Operating Representative shall be available to address and make decisions on all operational matters under this Agreement on a twenty-four (24) hour per day, seven (7) day per week basis. Supplier shall, at its expense, provide a protocol with Buyer’s Operating Representative at Buyer’s operations center and with Buyer’s scheduling personnel, as listed on Exhibit 4, to maintain communications between personnel at the Facility and Buyer’s Operating Representative, Buyer’s schedulers and Electric System Authorities at all times.

13.2 Communications. In connection with meeting its obligations pursuant to this Article 13, Supplier shall provide at its expense:

13.2.1 For the purposes of telemetering, a telecommunications circuit from the Facility to Buyer’s operations center, or other readily accessible real-time performance monitoring (e.g., a web-based performance monitoring system);

13.2.2 Two (2) dedicated T1 lines for purposes of accessing Buyer’s metering equipment and for communications with Buyer’s operations center, and

13.2.3 Equipment to transmit to and receive facsimiles and email from Buyer and the Balancing Authority Area Operator, including cellular telephones.

14. SCHEDULING NOTIFICATION

14.1 Availability Notice.

14.1.1 No later than 0500 PPT each day or as otherwise specified (or agreed to) by Buyer consistent with Good Utility Practice, Supplier shall deliver to Buyer’s Operating Representative an Availability Notice, in accordance with WECC scheduling protocols and deadlines, containing information including Supplier’s good faith daily and hourly forecast of the Delivered Amount, Full Requirements Period Charging Energy, Planned Outages, Derating, other outages and similar changes that may affect the Delivered Amount and the availability of Product in the form set forth in Exhibit 8. The Availability Notice will cover WECC scheduling practices for day-ahead energy or such other period specified by Buyer consistent with Good Utility Practice. The Parties agree to modify the Availability Notice as may
be required consistent with other scheduling practices which may be applicable to the Facility from time to time.

14.1.2 Supplier shall update the Availability Notice and notify Buyer’s Operating Representative as soon as practical after becoming aware of: (a) an expected Derating; (b) an expected change in Full Requirements Period Charging Energy, (c) an expected increase of Delivered Amount; or (d) reductions to estimated hourly Delivered Amount. The updated Availability Notice shall include Supplier’s best estimate of the time required to resolve the condition(s) that caused the reductions to the estimated hourly Delivered Amount.

14.1.3 The information in any Availability Notice, including the forecasted Delivered Amount, will be Supplier’s good faith forecast and will indicate any Delivery Hour for which the Delivered Amount is expected to be less than or greater than the Scheduled Amount.

14.1.4 In the event of a Derating of the Facility, Supplier shall provide: (a) the extent, if any, to which the Derating is attributable to a Planned Outage; (b) the magnitude of the Derating; (c) the Delivery Hours during which the Derating is expected to apply; and (d) the cause of the Derating.

14.2 Scheduling. Buyer’s right to schedule the Generating Facility during June, July and August is limited by Supplier’s schedule of Energy, Full Requirements Period Charging Energy, Supplier’s Charging Energy and Discharging Energy as utilized to meet its obligations during the Full Requirements Period. Supplier shall deliver Energy and operate the Generating Facility in order to comply with this Section 14.2, provided that, subject to Sections 3.6.1 and 3.6.2, the actual amount of Energy delivered by Supplier for any hour may be more than or less than the Scheduled Amount.

14.2.1 For the Dispatchable Period, except as provided above with respect to June, July and August, the Parties shall schedule energy to be delivered pursuant to this Agreement. All scheduling communications shall be by email or by telephone with an email confirmation. Buyer shall submit to Supplier each day’s hourly energy preschedule by the earlier of 0700 PPT or 30 minutes prior to the prescheduling deadline on each WECC prescheduling day, which shall provide notice of Buyer’s intent to schedule energy for the following day or days consistent with the then-current WECC prescheduling calendar (“Scheduled Amount”). Supplier shall electronically confirm the preschedule with Buyer by 0730 PPT on each WECC prescheduling day.

14.2.2 For changes in the Scheduled Amount that are not delivered by Buyer’s Energy Management System sending signals to Supplier’s AGC, Buyer shall have the right to change the Scheduled Amount on an intraday basis (“Intraday Schedule Change”) only if Buyer has provided at least one (1) hour’s notice prior to the delivery hour; provided, however, that Supplier
shall make commercially reasonable efforts to accommodate Intraday Schedule Changes upon less notice.

14.2.3 During the Full Requirements Period Buyer shall not, and shall not be obligated to, submit a schedule, and Supplier shall deliver Full Requirements Period Product in accordance with Exhibit 13A and B, provided that, subject to Section 3.6.4, the actual amount of Product delivered for any hour during the Full Requirements Period may be less than or more than the amounts set forth in Exhibit 13A and 13B.

14.2.4 Except as set forth in Section 14.3.2., during the months of June, July and August, Buyer’s schedule may be limited by the amount of Energy required by Supplier in its sole discretion for Full Requirements Period Charging Energy to charge the Storage Facility to meet Supplier’s obligations during the Full Requirements Period. In such event, Buyer’s schedules during any Dispatchable Period may be limited as set forth in any applicable Availability Notice.

14.3 Storage Facility Scheduling.

14.3.1 Subject to Section 14.3.2, during the Dispatchable Period (except the months of June, July and August), Buyer has the exclusive right to schedule or designate the Storage Facility to deliver the Storage Product to Buyer and/or accept Buyer Charging Energy, in accordance with the Storage Operating Procedures and the operational requirements specified in Exhibit 1. Except as set forth in Section 14.3.2, during the Full Requirements Period, Supplier may discharge the Storage Facility as it determines in its sole discretion.

14.3.2 Notwithstanding anything in this Agreement to the contrary, during the months of June, July and August, Buyer has the right to schedule, notwithstanding Supplier’s Availability Notice in Section 14.2, Energy and Discharging Energy from the Storage Facility, in which case (a) the Discharging Energy delivered from the Storage Facility during the Dispatchable Period, (b) any Energy that could have been used as Full Requirements Period Charging Energy, but was not able to be used by Supplier due to Buyer’s use of the Storage Facility or Generating Facility, and (c) Energy and Discharging Energy that could have been delivered to Buyer as Net Energy, but was not able to be delivered by Supplier due to Buyer’s use of the Storage Facility or Generating Facility, shall collectively be considered “FRP Deemed Delivered Energy”. The amount of FRP Deemed Delivered Energy will not be considered a shortfall for the Full Requirements Period and Buyer shall pay Supplier the Full Requirements Period Product Rate for the FRP Deemed Delivered Energy. Supplier has no obligation to charge the Storage Facility to satisfy Buyer’s Discharging Notice. The Storage Facility will only be discharged in accordance with Section 14.3.4 to ensure that Supplier can continue to use energy from the
Storage Facility to serve Station Usage notwithstanding Buyer’s scheduling of the Storage Facility under this Section 14.3.2.

14.3.3 The operational requirements specified in Exhibit 1 will allow Buyer to schedule the Storage Facility for seven (7) days per week and twenty-four (24) hours per day (including holidays) for all available components of the Storage Product, unless the Storage Facility is, in whole or in part, incapable of operations due to Force Majeure, Transmission Provider Instructions, an Emergency, a Planned Outage or a forced outage (but without relieving Supplier of any liability it may have for damages hereunder due to such forced outage). Subject to Sections 14.2 and 14.3.2, during the Term Supplier shall operate the Storage Facility to charge or discharge the Storage Facility in accordance with Buyer’s instruction pursuant to Section 3.4.8. The Storage Facility may only be charged with Charging Energy from the Generating Facility. Subject to Sections 14.2 and 14.3.2, during the Dispatchable Period Supplier shall not dispatch and operate the Storage Facility other than pursuant to an instruction by Buyer pursuant to Section 3.4.8.

14.3.4 Supplier shall be entitled to use Energy from the Generating Facility, when available, to serve Station Usage or to charge the Storage Facility so that it can be used to serve Station Usage, but Supplier’s use of Energy as described in this sentence will not excuse any failure by Supplier to meet its performance obligations hereunder. When the Generating Facility is not generating Energy, Supplier may use energy from the Storage Facility to serve Station Usage, but Supplier’s use of energy from the Storage Facility as described in this sentence will not excuse any failure by Supplier to meet its performance obligations hereunder.

15. COMPLIANCE

15.1 Laws. Each Party shall comply with all relevant Laws in connection with the performance of its obligations under this Agreement. Subject to Section 3.5, Supplier shall comply with all Laws to ensure that, the Generating Facility is at all times a Renewable Energy System and Supplier is at all times in compliance with all requirements of a renewable energy generator as set forth in the Renewable Energy Law, and shall, at its sole expense, maintain in full force and effect all relevant material Governmental Approvals required for the maintenance of the Facility and the performance of its obligations under this Agreement. Supplier shall be responsible for any costs associated with any obligations imposed on Supplier under the Clean Power Plan, including for obtaining, at its sole cost, any allowances that may be required for Supplier under applicable Law pertaining to the Clean Power Plan, in a quantity or amount sufficient to support Supplier’s obligations set forth in this Agreement. Each Party and its representatives shall comply with all relevant requirements of each Electric System Authority, Transmission Provider and each Governmental Authority to ensure the safety of its employees and the public.
15.2 **Good Utility Practice.** Each of Buyer and Supplier shall perform, or cause to be performed, its obligations under this Agreement in all material respects in accordance with Good Utility Practice.

15.3 **Interconnection Agreement.** Supplier shall operate the Facility in accordance with the IA and to the extent there is a conflict between this Agreement and the IA, the IA shall prevail.

16. **APPROVALS**

16.1 **Condition Precedent.** Unless Buyer waives its right to terminate or otherwise fails to exercise its right to terminate this Agreement pursuant to Section 16.3, then notwithstanding any provision to the contrary contained in this Agreement, each Party’s performance of its respective obligations under Articles 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15 of this Agreement is subject to: Buyer obtaining the PUCN Approval described in Section 16.2 before the PUCN Approval Deadline and in form and substance satisfactory to Buyer in its sole discretion.

16.2 **PUCN Approval.** Within one hundred twenty (120) days after the Effective Date and in accordance with the requirements of Law, Buyer shall submit this Agreement to the PUCN for approval (“PUCN Approval”) consisting of:

16.2.1 A determination that the terms and conditions of this Agreement are just and reasonable; and

16.2.2 A determination that the costs of purchasing Product under this Agreement are prudently incurred and that the Buyer may recover all just and reasonable costs of Product purchased under this Agreement.

16.3 **Failure to Obtain PUCN Approval; Conditions of PUCN Approval.** If the PUCN fails to grant the PUCN Approval on or before the PUCN Approval Deadline or grants the PUCN Approval on or before the PUCN Approval Deadline, but in form and substance not acceptable to Buyer in its sole discretion, then within thirty (30) days after the PUCN Approval Deadline or the date PUCN grants the PUCN Approval, as the case may be, Buyer shall have the right to terminate this Agreement upon ten (10) Business Days prior written notice to Supplier. Under no circumstances shall either Party have any liability to the other Party due to the failure of the PUCN to grant PUCN Approval by the PUCN Approval Deadline or the inclusion of conditions to the PUCN Approval which are unacceptable to Buyer.

16.4 **Cooperation.** If requested by Buyer, Supplier shall cooperate with Buyer as Buyer may deem necessary in order to obtain any Governmental Approval (including the PUCN Approval and any FERC approval) in connection with this Agreement, including providing affidavits, providing timely responses to data requests of the relevant Governmental Authority, intervening in any relevant dockets, and requesting “commenter” or “intervener” status in any relevant docket. Each Party agrees to notify the other Party of any significant developments in obtaining any
Governmental Approval in connection with achieving Commercial Operation of the Facility, including the PUCN Approval. Each Party shall use reasonable efforts to obtain such required Governmental Approvals and shall exercise due diligence and shall act in good faith to cooperate with and assist each other in acquiring each Governmental Approval necessary to effectuate this Agreement.

17. SECURITY

17.1 Development Security. As a condition of Buyer’s execution of and continuing obligations under this Agreement, Supplier shall provide to Buyer, as security for the performance of Supplier’s obligations hereunder, either: (a) a letter of credit from a Qualified Financial Institution substantially in the form attached hereto as Exhibit 17; (b) a cash deposit; (c) Guarantee from a Qualified Guarantor; or (d) a surety bond that is issued by a surety or insurance company that has an A.M. Best Financial Strength Rating (FSR) equal to or better than B+ or an equivalent Standard & Poor’s Ratings Services or Moody’s Investors Service rating (A- or A3) or that is otherwise acceptable to Buyer and in a form that is reasonably acceptable to Buyer, in any case, in an amount equal to twenty six million seven hundred fifty thousand dollars ($26,750,000) (the “Development Security”). The Development Security shall be posted within five (5) Business Days after the Effective Date. Upon the PUCN Approval Date, the Development Security shall increase to an amount equal to seventy four million, nine hundred thousand dollars ($74,900,000). The revised Development Security shall be posted within ten (10) days after the PUCN Approval Date and be maintained until fifteen (15) Business Days after the Commercial Operation Date. Buyer shall have the right to draw upon the Development Security, at Buyer’s sole discretion: (i) as a non-exclusive remedy available to Buyer under Article 24; (ii) in the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline and fails to pay Daily Delay Damages as provided in Section 8.5.1; (iii) if Supplier fails to make any payments owing under this Agreement; or (iv) if Supplier fails to reimburse Buyer for costs, including Replacement Costs, PC Replacement Costs and Regulatory Penalties, that Buyer has incurred or may incur as a result of Supplier’s failure to perform its obligations under this Agreement. Unless this Agreement is terminated, any such drawing on the Development Security by Buyer shall give rise to an obligation of Supplier to replenish the Development Security to its required amount within three (3) Business Days of the drawing. In the event that no amounts are due and owing by Supplier to Buyer under this Agreement and Supplier has provided the Operating Security to Buyer, the Development Security shall be released to Supplier upon the earlier of (x) termination of this Agreement in accordance with its terms or (y) on the fifteenth (15th) Business Day after the Facility achieves Commercial Operation. With the consent of Buyer, Supplier may apply and maintain the Development Security as a portion of Operating Security required to be provided by Supplier pursuant to Section 17.2. Notwithstanding the foregoing, in the event of a termination of this Agreement pursuant to Section 2.3.2 or Article 16, the Development Security shall be released to Supplier within five (5) Business Days after such termination.
17.2 **Operating Security.** As a condition to achieving Commercial Operation, Supplier shall provide to Buyer, as security for the performance of Supplier’s obligations hereunder, either: (a) a letter of credit from a Qualified Financial Institution substantially in the form attached hereto as Exhibit 17; (b) a cash deposit; (c) Guarantee from a Qualified Guarantor; or (d) a surety bond that is issued by a surety or insurance company that has an A.M. Best Financial Strength Rating (FSR) equal to or better than B+ or an equivalent Standard & Poor’s Ratings Services or Moody's Investors Service rating (A- or A3) or that is otherwise acceptable to Buyer and in a form that is reasonably acceptable to Buyer, in an amount equal to sixty eight million nine thousand five hundred dollars ($68,009,500) (the “Operating Security”). The Operating Security shall be posted no later than five (5) Business Days prior to the Commercial Operation Date. Buyer shall have the right to draw upon the Operating Security, at Buyer’s sole discretion: (1) as a non-exclusive remedy available to Buyer in the event this Agreement is terminated under Article 24; (2) in the event Supplier fails to make any payments owing under this Agreement; or (3) if Supplier fails to reimburse Buyer for costs, including Replacement Costs, PC Replacement Costs and Regulatory Penalties that Buyer has incurred or may incur as a result of Supplier’s failure to perform its obligations under this Agreement. Unless this Agreement is terminated, any such drawing on the Operating Security by Buyer shall give rise to an obligation of Supplier to replenish the Operating Security to its original amount within three (3) Business Days. In the event that no amounts are due and owing by Supplier to Buyer under this Agreement, the Operating Security shall be released to Supplier upon the fifteenth (15th) Business Day after the earlier of (x) termination of this Agreement in accordance with its terms or (y) the expiration of the Term.

17.3 **Letters of Credit.** With respect to any letter of credit posted by Supplier as Development Security or Operating Security: (a) no later than thirty (30) days prior to the expiration date of any such letter of credit, Supplier shall cause the letter of credit to be renewed or replaced with another letter of credit in an equal amount; (b) in addition to the conditions specified in Sections 17.1 and 17.2, Buyer shall have the right to draw on such letter of credit, at Buyer’s sole discretion (i) if such letter of credit has not been renewed or replaced at least thirty (30) days prior to the date of its expiration or (ii) if the Credit Rating of the financial institution that issued such letter of credit has been downgraded to below that required of a Qualified Financial Institution and Supplier has not caused a replacement letter of credit to be issued for the benefit of Buyer within five (5) Business Days of such downgrade pursuant to Section 17.4.

17.4 **Maintaining Letter of Credit.** If at any time after the Effective Date of this Agreement, Standard & Poor’s, Moody’s or another nationally recognized firm downgrades the Credit Rating of the financial institution issuing a letter of credit pursuant to this Agreement to below that required of a Qualified Financial Institution, then Supplier shall: (a) provide Buyer with written notice of such downgrade within two (2) Business Days of Supplier being notified of any such downgrade; and (b) cause a replacement letter of credit satisfying the conditions of Section 17.3 or other acceptable Development Security or Operating Security, as applicable, to be issued in favor of Buyer within five (5) Business Days of such
downgrade. In the event such a downgrade also constitutes an Event of Default pursuant to Article 24, then the requirements of this Section 17.4 are in addition to, and not in lieu of, the provisions of Article 24. Supplier shall take all necessary action and shall be in compliance with Section 17.1 and/or Section 17.2, as the case may be, within five (5) Business Days of the downgrade.

17.5 Guarantors. Supplier shall provide Buyer, or shall cause any guarantor to provide Buyer, audited financials of guarantor within ten (10) days of them becoming available. Further, Supplier shall promptly notify Buyer regarding downgrade or other material change regarding the creditworthiness or financial condition of any guarantor providing a Guarantee pursuant to Sections 17.1 or 17.2. If at any time after the Effective Date, any guarantor providing a Guarantee pursuant to Sections 17.1 or 17.2 experiences a downgrade or other material change described in the prior sentence and, as a result, such guarantor fails to meet the Minimum Credit Rating, if such guarantor has a Credit Rating, or fails to meet Buyer’s minimum credit requirements as determined by Buyer in its sole and absolute discretion, if such guarantor does not have a Credit Rating, then Buyer shall notify Supplier in writing and Supplier shall cause a replacement Guarantee, surety bond, letter of credit or cash meeting the requirements of Section 17.1 or 17.2, as applicable, and in the amount of the Development Security or Operating Security, as the case may be, to be delivered to Buyer within five (5) Business Days of such notice. Failure to provide the Development Security or Operating Security pursuant hereto in a timely manner shall constitute an Event of Default pursuant to Article 24.

17.6 No Interest on Supplier Security. Supplier shall not earn or be entitled to any interest on any security provided pursuant to this Article 17, including any cash amounts deposited.

17.7 Grant of Security Interest. To secure its obligations under this Agreement, Supplier hereby grants to Buyer, as the secured party, a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all Development Security or Operating Security, as the case may be, posted with Buyer in the form of cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Buyer. Supplier agrees to take such action as Buyer reasonably requires in order to perfect a first-priority security interest in, and lien on (and right of setoff against), such performance assurance and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default, Buyer, as the Non-Defaulting Party, may do any one or more of the following: (a) exercise any of the rights and remedies of a secured party with respect to all Development Security or Operating Security, as applicable, including any such rights and remedies under Law then in effect; (b) exercise its right of setoff against any and all property of Supplier, as the Defaulting Party, in the possession of the Buyer or Buyer’s agent; (c) draw on any outstanding letter of credit issued for its benefit; and (d) liquidate all Development Security or Operating Security, as applicable, then held by or for the benefit of Buyer free from any claim or right of any nature whatsoever by Supplier, including any equity or right of purchase or
redemption by Supplier. Buyer shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce Supplier’s obligations under the Agreement (Supplier remaining liable for any amounts owing to Buyer after such application), subject to the Buyer’s obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

17.8 **Waiver of Buyer Security.** Supplier hereby waives any and all rights it may have, including rights at Law or otherwise, to require Buyer to provide financial assurances or security (including cash, letters of credit, bonds or other collateral) in respect of its obligations under this Agreement.

17.9 **Security is Not a Limit on Supplier’s Liability.** Subject to Section 8.4.1, the security contemplated by this Agreement: (a) constitutes security for, but is not a limitation of, Supplier’s obligations hereunder; and (b) shall not be Buyer’s exclusive remedy for Supplier’s failure to perform in accordance with this Agreement.

**18. INDEMNIFICATION**

18.1 **Indemnification for Losses.** Each Party to this Agreement (the “Indemnifying Party”) shall indemnify, defend and hold harmless, on and after state and federal Tax basis, the other Party, its Affiliates, and each of their officers, directors, employees, attorneys, agents and successors and assigns (each an “Indemnified Party”) from, for and against any and all Losses arising out of, relating to, or resulting from the Indemnifying Party’s breach, or performance or non-performance of its obligations under this Agreement, including the Indemnifying Party’s negligence and willful misconduct (including reasonable attorneys’ fees and costs); provided, however, that no Indemnified Party shall be indemnified hereunder for any Loss to the extent resulting from its own gross negligence, fraud or willful misconduct. Supplier shall be solely responsible for (and shall defend and hold Buyer harmless against) any damage that may occur as a direct result of Supplier’s acts that affect the Transmission System.

18.1.1 In furtherance of the foregoing indemnification and not by way of limitation thereof, the Indemnifying Party hereby waives any defense it otherwise might have against the Indemnified Party under applicable workers’ compensation Laws.

18.1.2 In claims against any Indemnified Party by an agent of the Indemnifying Party, or anyone directly or indirectly employed by them or anyone for whose acts the Indemnifying Party may be liable, the indemnification obligation under this Article 18 shall not be limited by a limitation on amount or type of damages, compensation or benefits payable by or for the Indemnifying Party or a subcontractor under workers’ or workmen’s compensation acts, disability benefit acts or other employee benefit acts.

18.2 **No Negation of Existing Indemnities; Survival.** Each Party’s indemnity obligations under this Agreement shall not be construed to negate, abridge or reduce other
rights or obligations, which would otherwise exist at Law or in equity. The obligations contained herein shall survive the termination or expiration of this Agreement to the extent that any third-party claim is commenced during the applicable statute of limitations period.

18.3 Indemnification Procedures.

18.3.1 Any Indemnified Party seeking indemnification under this Agreement for any Loss shall give the Indemnifying Party notice of such Loss promptly but in any event on or before thirty (30) days after the Indemnified Party’s actual knowledge of such claim or action. Such notice shall describe the Loss in reasonable detail, and shall indicate the amount (estimated if necessary) of the Loss that has been, or may be sustained by, the Indemnified Party. To the extent that the Indemnifying Party will have been actually and materially prejudiced as a result of the failure to provide such notice, the Indemnified Party shall bear all responsibility for any additional costs or expenses incurred by the Indemnifying Party as a result of such failure to provide notice.

18.3.2 In any action or proceeding brought against an Indemnified Party by reason of any claim indemnifiable hereunder, the Indemnifying Party may, at its sole option, elect to assume the defense at the Indemnifying Party’s expense, and shall have the right to control the defense thereof and to determine the settlement or compromise of any such action or proceeding. Notwithstanding the foregoing, an Indemnified Party shall in all cases be entitled to control its own defense in any action if it:

18.3.2.1 May result in injunctions or other equitable remedies with respect to the Indemnified Party;

18.3.2.2 May result in material liabilities which may not be fully indemnified hereunder; or

18.3.2.3 May have a Material Adverse Effect on the Indemnified Party (including a Material Adverse Effect on the Tax liabilities, earnings, ongoing business relationships or regulation of the Indemnified Party) even if the Indemnifying Party pays all indemnification amounts in full.

18.3.3 Subject to Section 18.3.2, neither Party may settle or compromise any claim for which indemnification is sought under this Agreement without the prior written consent of the other Party; provided, however, that said consent shall not be unreasonably withheld, conditioned or delayed.

19. LIMITATION OF LIABILITY

19.1 Responsibility for Damages. Except where caused by the other Party’s breach, negligence or non-performance of its obligations under this Agreement, each Party
shall be responsible for all physical damage to or destruction of the property, equipment and/or facilities owned by it, and each Party hereby releases the other Party from any reimbursement for such damage or destruction.

19.2 Limitation on Damages. To the fullest extent permitted by Law and notwithstanding any other provisions of this Agreement to the contrary, except for Replacement Costs, PC Replacement Costs or payment made by either Party to satisfy Regulatory Penalties or payments owing under Sections 3.4, 3.5, 3.6, 3.7, 7.5, 8.4, 8.5, 15.1, 17.1, 17.2, 18.1, 19.1, 27.1, in no event shall a Party be liable to the other Party, whether in contract, warranty, tort, negligence, strict liability, or otherwise, for special, indirect, incidental, multiple, consequential (including lost profits or revenues, business interruption damages and lost business opportunities), exemplary or punitive damages related to, arising out of, or resulting from performance or nonperformance of this Agreement (unless due to the willful or intentional breach of this Agreement by such Party, in which case the limitation shall not apply). In addition, this limitation on damages shall not apply with respect to claims brought by third parties for which a Party is entitled to indemnification under this Agreement.

19.3 Survival. The provisions of this Article 19 shall survive the termination or expiration of this Agreement.

20. FORCE MAJEURE

20.1 Excuse. Subject to Section 20.4, neither Party shall be considered in default under this Agreement for any delay or failure in the performance of its obligations under this Agreement (including any obligation to deliver or accept Product) if such delay or failure is due to an event of Force Majeure.

20.2 Definition. “Force Majeure” or “an event of Force Majeure” means an event that: (a) is not reasonably anticipated as of the Effective Date; (b) is not within the reasonable control of the Party affected by the event; (c) is not the result of the affected Party’s negligence or failure to act; and (d) could not be overcome by the affected Party’s use of due diligence in the circumstances. Force Majeure includes, but is not restricted to, events of the following types (but only to the extent that such an event, in consideration of the circumstances, satisfies the requirements set forth in the preceding sentence): acts of God; civil disturbance; sabotage; strikes not attributable to Supplier’s actions; lock-outs not attributable to Supplier’s actions; work stoppages not attributable to Supplier’s actions; action or restraint by court order or Governmental Authority (as long as the affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such action or restraint).

20.3 Exclusions. Notwithstanding the foregoing, none of the following shall constitute Force Majeure:

20.3.1 Economic hardship of either Party, including lack of money;
20.3.2 The non-availability or reduced availability of the resource supply to generate electricity from the Generating Facility, including due to weather, high or low temperatures or climate conditions, except to the extent caused by acts of God;

20.3.3 A Party’s failure to obtain any Governmental Approval from a Governmental Authority;

20.3.4 A Party’s failure to meet a Project Milestone, except to the extent it is caused by an event of Force Majeure;

20.3.5 The imposition of costs or Taxes on a Party;

20.3.6 Supplier’s failure to obtain, or perform under, the IA, or its other contracts and obligations to Transmission Provider unless due to a Force Majeure event;

20.3.7 Supplier’s ability to sell, or Buyer’s ability to purchase energy, PCs (and equivalent rights in any other jurisdiction), Renewable Energy Benefits, or Capacity Rights at a more advantageous price than is provided hereunder;

20.3.8 Any breakdown or malfunction of the Facility’s equipment (including any serial equipment defect) that is not caused by an independent event of Force Majeure;

20.3.9 Delay or failure of Supplier to obtain or perform any Required Facility Document unless due to a Force Majeure event;

20.3.10 Any delay, alleged breach of contract, or failure by the Transmission Provider unless due to a Force Majeure event;

20.3.11 Maintenance upgrade or repair of any facilities or right of way corridors whether performed by or for Supplier, or other third parties (except for repairs made necessary as a result of an event of Force Majeure); or

20.3.12 The increased cost of electricity, equipment, steel, labor, or transportation.

20.4 Conditions. In addition to the conditions set forth in Section 20.2, a Party may rely on a claim of Force Majeure to excuse its performance only to the extent that such Party:

20.4.1 Provides prompt notice of such Force Majeure event to the other Party, giving an estimate of its expected duration and the probable impact on the performance of its obligations under this Agreement (which notice, in the case of Supplier, shall be provided within forty-eight (48) hours following such Force Majeure event);
20.4.2 Exercises all reasonable efforts to continue to perform its obligations under this Agreement;

20.4.3 Expeditiously takes action to correct or cure the Force Majeure event excusing performance so that the suspension of performance is no greater in scope and no longer in duration than is dictated by the event; provided, however, that nothing herein requires a Party to settle a strike or other labor dispute;

20.4.4 Exercises all reasonable efforts to mitigate or limit damages to the other Party resulting from the Force Majeure event; and

20.4.5 Provides prompt notice to the other Party of the cessation of the Force Majeure event giving rise to its excuse from performance.

21. DISPUTES

21.1 Dispute or Claim. Any cause of action, claim or dispute which either Party may have against the other Party arising out of or relating to this Agreement, including the interpretation of the terms hereof or any Laws that affect this Agreement, or the transactions contemplated hereunder, or the breach, termination or validity hereof ("Dispute") shall be submitted in writing to the other Party. The written submission of any Dispute shall include a concise statement of the question or issue in dispute together with a statement listing the relevant facts and appropriate supporting documentation.

21.2 Good Faith Resolution. The Parties agree to cooperate in good faith to expedite the resolution of any Dispute. Pending resolution of a Dispute, the Parties shall proceed diligently with the performance of their obligations under this Agreement.

21.3 Informal Negotiation. The Parties shall first attempt in good faith to resolve any Dispute through informal negotiations by the Operating Representatives or Contract Representatives and senior management of each Party. If the Parties fail to resolve any Dispute through informal negotiations within thirty (30) days after the Dispute is submitted in writing to the other Party in accordance with Section 21.1, then either Party may (a) send a Technical Dispute Notice for a Dispute regarding the calculation of Availability Backcast Amounts or the Resource-Adjusted Backcast Amount, or (b) for any other Dispute, exercise their rights at equity or law to resolve such Dispute.

21.4 Technical Expert. If the Dispute regards the calculation of Availability Backcast Amounts or the Resource-Adjusted Backcast Amount, then the Parties will have such Dispute resolved pursuant to this Section 21.4. Any such Dispute will be determined by an independent technical expert, who shall be a mutually acceptable third party with training and experience in the disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion (the "Technical Expert"), which determination shall be (x) except as otherwise provided in this Section 21.4, made
in accordance with the Construction Industry Arbitration Rules and Mediation Procedures (Including Procedures for Large, Complex Construction Disputes) of the American Arbitration Association ("AAA"), as amended and effective on the date a Party provides notice of its intent to submit the Dispute to a technical expert, and (y) binding upon the Parties.

21.4.1 Either Party may commence the technical dispute process with AAA by notifying AAA and the other Party in writing ("Technical Dispute Notice") of such Party's desire that the Dispute be resolved through a determination by a technical expert.

21.4.2 The determination shall be conducted by a sole Technical Expert. The Parties may select any mutually acceptable Technical Expert. If the Parties cannot agree on a Technical Expert within five (5) days after the date of the Technical Dispute Notice, then the AAA's arbitration administrator shall send a list and resumes of three (3) available technical experts meeting the qualifications set forth in Section 21.4 to the Parties, each of whom shall strike one name, and the remaining person shall be appointed as the Technical Expert. If more than one name remains, either because one or both Parties have failed to respond to the AAA's arbitration administrator within five (5) days after receiving the list or because one or both Parties have failed to strike a name from the list or because both Parties strike the same name, the AAA's arbitration administrator will choose the Technical Expert from the remaining names. If the designated Technical Expert shall die, become incapable or, unwilling to, or unable to serve or proceed with the determination, a substitute technical expert shall be appointed in accordance with the selection procedure described above, and such substitute Technical Expert shall have all such powers as if he or she has been originally appointed herein.

21.4.3 Within thirty (30) days of the appointment of the Technical Expert pursuant to Section 21.4.2, each Party shall submit to the Technical Expert a written report containing its position with respect to the Dispute, and arguments therefor together with supporting documentation and calculations. Discovery shall be limited to Facility documentation relating to the Dispute. Within sixty (60) days from receipt of such submissions, the Technical Expert shall select one or the other Party's position with respect to the Dispute, whereupon such selection shall be a binding determination upon the Parties for all purposes hereof. The costs of the determination by the Technical Expert of any Dispute, including fees and expenses, shall be borne by the Party whose position was not selected by the Technical Expert. If the Technical Expert fails to render a decision within ninety (90) days from receipt of each Party's submissions, either Party may initiate litigation in accordance with the provisions herein.

21.4.4 All verbal and written communications between the Parties and issued or prepared in connection with this Section 21.4 shall be deemed prepared and communicated in furtherance, and in the context, of dispute settlement, and
shall be exempt from discovery and production, and shall not be admissible in evidence (whether as admission or otherwise) in any litigation or other proceedings for the resolution of the Dispute.

21.4.5 All deadlines specified in this Section 21.4 may be extended by mutual agreement of the Parties.

21.5 Jurisdiction, Venue. Each Party irrevocably: (a) submits to the exclusive jurisdiction of the federal and state courts located in the County of Washoe, State of Nevada; (b) waives any objection which it may have to the laying of jurisdiction or venue of any proceedings brought in any such court; and (c) waives any claim that such proceedings have been brought in an inconvenient forum.

21.6 Recovery of Costs and Attorneys’ Fees. In the event of a Dispute arising from or relating to this Agreement, whether or not an action is commenced in any court to enforce any provision or for damages by reason of any alleged breach of this Agreement, the prevailing Party will be entitled to recover from the other Party all costs and attorneys’ fees reasonably incurred in resolving the Dispute. For purposes hereof, the “prevailing” Party need not prevail on every issue involved in the Dispute, but only on the main issue giving rise to the Dispute.

21.7 Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

22. NATURE OF OBLIGATIONS

22.1 Relationship of the Parties. The provisions of this Agreement shall not be construed to create an association, trust, partnership, or joint venture; or impose a trust or partnership duty, obligation, or liability or agency relationship between the Parties.

22.2 No Public Dedication. By this Agreement, neither Party dedicates any part of its facilities nor the services provided under this Agreement to the public.

23. ASSIGNMENT

Except as stated below, neither this Agreement nor any of the rights or obligations hereunder shall be assigned by either Party, including by operation of Law, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Any assignment of this Agreement in violation of the foregoing shall be, at the option of the non-assigning Party, void.
23.1 **Buyer Assignment.** Buyer may, without the consent of Supplier, assign this Agreement or assign or delegate its rights and obligations under this Agreement, in whole or in part, if such assignment or delegation is made to: (a) Sierra Pacific Power Company; (b) any successor to Buyer, provided that such successor is a public utility holding a certificate of public convenience and necessity granted by the PUCN pursuant to NRS Chapter 704, where such assignment does not occur by operation of Law; (c) a Person (other than a natural person) providing retail electric service in Nevada and which meets the Minimum Credit Rating; (d) a wholesale electric provider which meets the Minimum Credit Rating or provides adequate credit assurance or a guarantee from a party that meets the Minimum Credit Rating; (e) a Person (other than a natural person) whose Credit Rating, as published by either Relevant Rating Agency, is equal or superior to the Minimum Credit Rating as of the time of assignment and provided such assignment would not have a material adverse regulatory consequence on Supplier; or (f) a Person (other than a natural person) as otherwise required by Law which meets the Minimum Credit Rating and provided such assignment would not have a material adverse regulatory consequence on Supplier. Buyer shall provide Supplier with written notice of any assignment pursuant to this Section 23.1.

23.2 **Supplier Assignment.** Supplier may, without the consent of Buyer (and without relieving itself from liability hereunder), transfer or assign a Controlling Interest in Supplier to any of Supplier's Affiliates or this Agreement to any of Supplier's Affiliates in connection with a transfer of the Facility to such Affiliate or a corporate reorganization between Supplier and its Affiliates so long as the purposes of the ROFO in Article 6 are not frustrated by such a transfer or assignment; provided that Supplier provides Buyer prior notice of any such transfer or assignment and (a) either (i) the Credit Rating of such Affiliate is equal to or superior to the Credit Rating of Supplier as of the Effective Date, as determined by Buyer in its reasonable discretion, or (ii) the Development Security or Operational Security, as applicable, is maintained without change due to such transfer or assignment or is replaced with Development Security or Operational Security, as applicable, in accordance with the requirements of Article 17, and (b) such Affiliate enters into an assignment and assumption agreement, in form and substance satisfactory to Buyer, pursuant to which such Affiliate assumes all of Supplier’s obligations hereunder and otherwise agrees to be bound by the terms of this Agreement. Supplier agrees that it will provide written notice to Buyer (and, if required, the PUCN Regulatory Operations Staff, and the State of Nevada Attorney General’s Bureau of Consumer Protection) of any transfer or assignment of this Agreement by Supplier to an Affiliate pursuant to this Section 23.2, together with information supporting the permissible nature of the transfer or assignment in accordance with the requirements of this Section 23.2, no less than five (5) Business Days prior to the effective date of any such transfer or assignment.

23.3 **Liability After Assignment.** A Party’s assignment or transfer of rights or obligations pursuant to this Article 23 (other than Section 23.2) of this Agreement shall relieve such Party from any liability and financial responsibility for the performance thereof arising after any such transfer or assignment, provided that such transferee
enters into an assignment and assumption agreement, in form and substance satisfactory to the other Party, pursuant to which such transferee assumes all of the assigning or transferring Party’s obligations hereunder and otherwise agrees to be bound by the terms of this Agreement.

23.4 Transfers of Ownership. Subject to the provisions of Article 6, Supplier shall not directly or indirectly sell, transfer, assign or otherwise dispose of its ownership interest in the Facility to any third party absent: (a) a transfer of this Agreement to such third party; (b) Supplier entering into an assignment and assumption agreement, in form and substance satisfactory to Buyer, with such third party pursuant to which such third party assumes all of Supplier’s obligations hereunder and otherwise agrees to be bound by the terms of this Agreement; (c) Buyer’s prior written approval, not to be unreasonably withheld, of such third party; and (d) such third party being a Qualified Transferee. This Section 23.4 shall not apply or restrict any sale, transfer, assignment or disposal of the Facility in accordance with the provisions of Section 6.6, Section 23.2, or Section 23.8. This Section 23.4 shall also not apply to any sale, transfer, assignment or disposal of the Facility to a third party pursuant to any Restricted Transaction(s) permitted in accordance with the ROFO provisions of Section 6.1, provided that such transfer is to a Qualified Transferee.

23.5 Controlling Interest. Subject to the provisions of Article 6, no Controlling Interest in Supplier may be directly or indirectly sold, transferred or assigned (whether through a single transaction or a series of transactions over time) without Buyer’s prior written approval, not to be unreasonably withheld, and then only to a Qualified Transferee. This Section 23.5 shall not apply or restrict any sale, transfer or assignment of a Controlling Interest in Supplier (a) in accordance with the provisions of Section 6.6 or Section 23.2, (b) that is a Permitted Transfer, or (c) pursuant to any Restricted Transaction(s) permitted in accordance with the ROFO provisions of Section 6.1, provided that such transfer is to a Qualified Transferee.

23.6 Assignee Obligations with Respect to Granting a Security Interest. As a condition precedent to granting any Person a security interest in the Facility, Supplier shall (a) satisfy the requirements of Section 23.8 or (b) procure and deliver to Buyer an agreement, enforceable by Buyer and in form and substance satisfactory to Buyer, from each such Person to the effect that, if such Person forecloses on its security interest, (i) it will assume Supplier’s obligations under and otherwise be bound by the terms of this Agreement, and (ii) it will not sell, transfer or otherwise dispose of its interest in the Facility to any Person other than in accordance with the provisions of this Article 23.

23.7 Successors and Assigns. This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective permitted successors and permitted assigns.

23.8 Collateral Assignment by Supplier. Supplier may, without the consent of Buyer (and without relieving itself from liability hereunder), transfer, pledge, encumber or collaterally assign this Agreement or the account, revenues or proceeds hereof to Supplier’s Lender in connection with any financing, including tax equity
financing, or other financial arrangements for the Facility. In the event that Supplier intends to transfer, pledge, encumber or collateralize assign this Agreement to Supplier’s Lenders, Supplier shall provide at least thirty (30) days’ prior written notice thereof to Buyer, including the address of Supplier’s Lenders. Any negotiation of documentation required in connection with a collateral assignment or other financing activity of Supplier shall be at the sole cost and expense of Supplier, and Supplier shall reimburse Buyer for all documented third-party and internal costs in connection with such activities. As a condition precedent to the effectiveness of any such transfer, pledge, encumbrance or collateral assignment to Supplier’s Lenders, Buyer and Supplier and Supplier’s Lenders shall have entered into a consent to collateral assignment agreement, which agreement shall be substantially in the form and substance of the Lender’s Consent in Exhibit 19, including such revisions as may be reasonably requested by Supplier’s Lenders.

24. DEFAULT AND REMEDIES

24.1 Events of Default. An event of default (‘Event of Default’) shall be deemed to have occurred with respect to a Party (the ‘Defaulting Party’) upon the occurrence of one or more of the following events and expiration of any applicable Cure Period:

24.1.1 failure to comply with any of its material obligations under this Agreement (not otherwise specifically addressed below) or failure of any of its representations or warranties in this Agreement to be true and correct in all material respect when made or deemed made;

24.1.2 failure to make timely payments due under this Agreement;

24.1.3 failure to comply with the material requirements of any Electric System Authority, Transmission Provider or any Governmental Authority;

24.1.4 in the case of Supplier, its failure at any time to qualify and maintain, subject to Section 3.5, the Generating Facility as a Renewable Energy System;

24.1.5 in the case of Supplier, its failure to install, operate, maintain or repair the Facility in accordance in all material respects with Good Utility Practice;

24.1.6 in the case of Supplier, unless excused by an event of Force Majeure, its failure to timely achieve: (a) any of the Critical Project Milestones (excluding Commercial Operation) before the scheduled date set forth in Exhibit 6; and (b) Commercial Operation by the Commercial Operation Deadline as set forth in Exhibit 6, after expiration of the applicable period for which Daily Delay Damages are owed by Supplier pursuant to Section 8.5.1;

24.1.7 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.2.4.
24.1.8 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.2.5.

24.1.9 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.4.3.

24.1.10 in the case of Supplier, its failure to comply with the provisions of Section 17 (including any replenishment requirement);

24.1.11 its failure to comply with the provisions of Section 23;

24.1.12 in the case of Supplier, its failure to comply with the provisions of Section 27;

24.1.13 in the case of Supplier, if Supplier: (a) becomes insolvent, files for or is forced into bankruptcy (and in the case of an involuntary bankruptcy, such proceeding is not dismissed within sixty (60) days); (b) makes an assignment for the benefit of creditors; (c) is unable to pay its debts as they become due; or (d) is subject to a similar action or proceeding (and in the case of an involuntary bankruptcy, such proceeding is not dismissed within sixty (60) days); and

24.1.14 in the case of Supplier, if Supplier: (a) relinquished possession and control of all or substantially all of the Facility, other than pursuant to a transfer permitted under this Agreement; or (b) after commencement of the construction of the Facility, and prior to the Commercial Operation Date, completely ceases construction, testing, and inspection of the Facility for ninety (90) consecutive days, if not attributable to an Event of Default of, or request by Buyer, or an event of Force Majeure; and

24.1.15 in the case of Supplier, if: (a) the Storage Contract Capacity of the Storage Facility determined pursuant to a Storage Capacity Test is less than or equal to ninety percent (90%) of the Storage Contract Capacity that was in effect as of the Commercial Operation Date for at least two (2) consecutive Contract Years; or (b) the Monthly Storage Availability is less than or equal to seventy-five percent (75%) for at least three (3) consecutive Dispatch Availability Months during any Contract Year or any five (5) non-consecutive Dispatch Availability Months during a period of two (2) consecutive Contract Years.

24.2 Duty/Right to Mitigate. Each Party has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party’s performance or non-performance of its obligations under this Agreement. For the purpose of this Section 24.2, commercially reasonable efforts by Supplier shall include seeking to maximize the price for Product received by Supplier from third parties, including entering into an enabling agreement with, or being affiliated with, one or more power marketers of nationally recognized standing to market such Product not purchased or accepted
by Buyer during a period Buyer is a Defaulting Party and Supplier is entitled to sell such Product to third parties in accordance with the terms of this Agreement.

24.3 **Cure Period.** Other than for an Event of Default under Sections 24.1.6 or 24.1.13 or 24.1.15 for which there is no cure period, an Event of Default shall not be deemed to have occurred under Section 24.1, unless and until the Defaulting Party shall: (a) for purposes of Section 24.1.2, 24.1.7, 24.1.8, 24.1.9, and 24.1.11, had a period of ten (10) Business Days from the date the applicable payment or performance was due; and (b) for purposes of all other Events of Default described in Section 24.1 (other than Sections 24.1.2, 24.1.6, 24.1.7, 24.1.8, 24.1.9, 24.1.11, 24.1.13 or 24.1.15 which are addressed above), had a period of thirty (30) days from the date of receipt of written notice of the occurrence of any of the Events of Default described in Section 24.1 (each of the cure periods in Section 24.3(a) and (b), a “Cure Period”) to cure such potential Event of Default; provided that such thirty (30)-day period may be extended for an additional reasonable period of time (not to exceed ninety (90) days) if: (i) the potential Event of Default is not reasonably capable of being cured within such thirty (30)-day period; (ii) such potential Event of Default is capable of being cured within an additional reasonable period of time (not to exceed ninety (90) days); and (iii) Supplier is diligently and continuously proceeding to cure such potential Event of Default.

24.4 **Remedies.** If an Event of Default is not cured by the Defaulting Party during the applicable Cure Period, if any, then, subject to Section 8.4.1, the Non-Defaulting Party shall be entitled to all legal and equitable remedies that are not expressly prohibited by the terms of this Agreement, including termination of this Agreement as provided in Section 2.3, payment of damages, and in the case of Buyer, drawing upon the Development Security and the Operating Security.

24.5 **Termination of Duty to Buy.** If this Agreement is terminated because of an Event of Default by Supplier, neither Supplier nor any Affiliate of Supplier, nor any successor to Supplier with respect to the ownership of the Facility or the Project Site, may thereafter require or seek to require Buyer to make any purchases from the Facility or any electric generation facility constructed on the Project Site, under the Public Utility Regulatory Policies Act of 1978 or any other Law, for any periods that would have been within the Term had this Agreement remained in effect. Supplier, on behalf of itself and any other entity on whose behalf it may act, hereby waives its rights to require Buyer so to do.

24.5.1 **Right of First Offer for Product.** If Buyer terminates this Agreement in accordance with Section 2.3.1 due to a Supplier Event of Default, then neither Supplier nor Supplier’s Affiliates may sell, or enter into a contract to sell, Net Energy or any Product generated by, associated with or attributable to a generating facility that from time to time may be constructed by Supplier or any Affiliate of Supplier on the Project Site installed at the Project Site to a party other than Buyer for a period of three (3) years following the effective date of such termination (“Restricted Period”). The foregoing prohibition on contracting and sale will not apply if, before entering into such contract or making a sale to a party other than
Buyer, Supplier or Supplier’s Affiliate provides Buyer with a written offer to sell the Net Energy or any Product to Buyer at the rate set forth in this Agreement and otherwise on terms and conditions materially similar to the terms and conditions set forth in this Agreement and Buyer fails to accept such offer within (A) forty-five (45) days after Buyer’s receipt of such offer if this Agreement had originally been terminated by Buyer after the commencement of construction of the Facility, and (B) one hundred twenty (120) days after Buyer’s receipt of such offer if this Agreement had originally been terminated by Buyer prior to the commencement of construction of the Facility. If Buyer elects to purchase such Product, then the Parties shall enter into a binding agreement consistent with the foregoing and otherwise on terms and conditions substantially similar with this Agreement, the same being modified only as necessary to address changes which arise due to the passage of time. Neither Supplier nor Supplier’s Affiliates may sell or transfer the Facility, or any part thereof, or their land rights or interests in the Project Site (including the interconnection queue position) during the Restricted Period so long as the limitations contained in this Section 24.5.1 apply, unless the transferee agrees to be bound by the terms set forth in this Section 24.5.1 pursuant to a written agreement approved by Buyer. Notwithstanding the above prohibition on a sale of transfer, this prohibition will not prevent the sale by Supplier or Supplier’s Affiliates of their interests in the Project Site to a third party if an independent engineer provides a notarized certification to the fact that a solar facility cannot be developed on the Project Site. Buyer shall be permitted to file a notice of the rights contained in this Section 24.5.1 with respect to the Supplier’s and Supplier’s Affiliates’ interests in the Project Site. Supplier shall indemnify and hold Buyer harmless from all Losses sustained by Buyer as a result of any breach of the covenants contained in this Section 24.5.1.

24.6 Step-In Rights.

24.6.1 Step-In Rights following an Event of Default. The Buyer step-in rights described in this Section 24.6 are subject to and subordinate to the rights of Supplier’s Lenders set forth in this Agreement and any consent to collateral assignment agreement entered into by Buyer and Supplier’s Lenders. If Supplier commits an Event of Default, including pursuant to Section 24.1.6(b), and this Agreement has not been terminated by Buyer, then without limiting its other rights and remedies hereunder, Buyer shall have the right to enter the Project Site and take possession of the Facility and to take or cause to be taken all such actions and do or cause to be done all such things as Buyer may consider necessary or desirable to cure the Event of Default, including to complete the Facility and cause Commercial Operation to occur. Following the cure of the Event of Default, Buyer shall: (a) return possession of the Facility to Supplier upon execution by Supplier of an indemnity and release agreement, in form and substance reasonably acceptable to Buyer, pursuant to which Supplier shall indemnify and release Buyer from all claims arising out of Buyer’s exercise of its rights pursuant
to this Section 24.6; or (b) failing the execution of such indemnity and release agreement: (i) operate the Facility for all or such portion of the remaining Term as Buyer may elect, in its sole discretion, pursuant to the license granted in Section 24.6.2; and/or (ii) exercise its other rights and remedies under this Agreement, including the right to terminate this Agreement without the payment of any damages by Buyer.

24.6.2 License to Operate Facility. Supplier hereby irrevocably grants to Buyer the right, license and authority to enter the Project Site, to construct, operate and maintain the Facility for the Term during the continuance of and following any Event of Default by Supplier. During any period in which Buyer constructs, operates or maintains the Facility pursuant to the license granted in this Section 24.6.2, Supplier shall, upon request from Buyer, reimburse Buyer for all reasonable costs and expenses incurred by Buyer to construct, operate and maintain the Facility.

24.6.3 Records and Access. Supplier shall collect and have available at a convenient, central location at the Project Site all documents, contracts, books, manuals, reports, and records required to construct, operate and maintain the Facility in accordance with Good Utility Practice. Upon Buyer’s notice of intent to exercise its rights under this Section 24.6, Buyer, its employees, contractors, or designated third parties shall have the right to enter the Project Site and the Facility for the purpose of constructing, operating or maintaining the Facility. Upon the exercise by Buyer of the rights under this Section 24.6, Supplier shall cause the Facility contractor or operator (and any Person within the control of Supplier) to give Buyer access to and control of the construction, operation and maintenance of the Facility, as applicable, to the extent reasonably necessary to enable Buyer to exercise its rights under this Section 24.6, and shall provide reasonable assistance and cooperation to Buyer to effect safely the transfer of responsibility for construction, operation and maintenance as may be requested by Buyer. Supplier shall execute such documents and take such other action as may be necessary for Buyer to effectuate its rights under this Section 24.6.

24.6.4 Return. Buyer may, at any time and in its sole discretion, terminate its exercise of its rights under this Section 24.6 whether or not the applicable Event of Default has been cured. If at any time after exercising its rights under this Agreement, Buyer elects to return possession of the Facility to Supplier, Buyer shall provide Supplier with at least ten (10) days advance notice of the date Buyer intends to return such possession, and upon receipt of such notice Supplier shall take all actions necessary to resume possession of the Facility on such date.

24.6.5 No Assumption. Buyer’s exercise of its rights under this Section 24.6 shall not be deemed an assumption by Buyer of any liability of Supplier due and owing prior to the exercise of such rights. Buyer shall not assume any liability of Supplier for the period during which Buyer exercises its rights.
under this Section 24.6. During any period that Buyer is exercising its rights, Supplier shall retain legal title to and ownership of the Facility and all of its other property and its revenues. When exercising its rights under this Section 24.6, Buyer shall assume possession, operation, and control of the Facility solely as agent for Supplier. In no event shall Buyer’s election to exercise its rights under this Section 24.6 be deemed to constitute a transfer of ownership of or title to the Facility, the Project Site or any assets of Supplier.

24.6.6 Costs and Expenses. Supplier shall indemnify and hold harmless Buyer from and against all Losses incurred by Buyer in connection with exercise of its rights under this Section 24.6 other than due to the negligence or willful misconduct of Buyer. In connection with its exercise of its rights under this Section 24.6, Buyer shall have the right to recoup and set off all such Losses against amounts otherwise owed by Buyer hereunder. Buyer’s exercise of such recoupment and set off rights shall not limit the other rights and remedies available to Buyer hereunder or otherwise.

25. REPRESENTATIONS AND WARRANTIES OF SUPPLIER

Supplier represents and warrants to Buyer as of the Effective Date and for the term of this Agreement and at the Commercial Operation Date as set forth in Sections 25.1 through 25.12, and covenants to Buyer as set forth in Sections 25.13 through 25.15:

25.1 Organization. Supplier is a limited liability company duly organized, validly existing and in good standing under the Laws of the State of Delaware and has all requisite entity power and authority to own or lease and operate its properties and to carry on its business as is now being conducted. Supplier is duly qualified or licensed to do business and is in good standing in the State of Nevada and in each other jurisdiction in which the property owned, leased or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not reasonably be expected to have a Material Adverse Effect on Supplier.

25.2 Authority. Supplier has full authority to execute, deliver and perform its obligations under this Agreement and to consummate the transactions contemplated herein and has taken all corporate actions necessary to authorize the execution, delivery and performance of its obligations under this Agreement. No other proceedings or approvals on the part of Supplier are necessary to authorize this Agreement. This Agreement constitutes a legal, valid and binding obligation of Supplier enforceable in accordance with its terms except as the enforcement thereof may be limited by (a) applicable bankruptcy, insolvency or similar Laws affecting the enforcement of creditors’ rights generally and (b) general principles of equity, whether considered in a proceeding in equity or at law.

25.3 Governmental Approvals; No Violation. Other than obtaining the Supplier’s Required Regulatory Approvals as set out in Exhibit 10, the execution, delivery and performance of this Agreement by Supplier shall not: (a) conflict with or result in
any breach of any provision of the articles of organization (and/or other governing documents) of Supplier; (b) require any Governmental Approval, except where the failure to obtain such Governmental Approval would not reasonably be expected to have a Material Adverse Effect on Supplier; or (c) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, agreement, lease or other instrument or obligation to which Supplier or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained.

25.4 **Regulation as a Utility.** Except for its anticipated future status as a "public utility" as defined in the Federal Power Act, and as set forth in Exhibit 10, Supplier is not subject to regulation as a public utility or public service company (or similar designation) by any Governmental Authority.

25.5 **Availability of Funds.** Supplier has, or will have, and shall maintain sufficient funds available to it to perform all of its obligations under this Agreement and to consummate the transactions contemplated pursuant hereto.

25.6 **Interconnection Process: Transmission.** Supplier has initiated with the Transmission Provider the process of obtaining the rights to interconnect the Facility to the Transmission System in order to provide for the delivery of Net Energy and Discharging Energy to and at the Delivery Points.

25.7 **Interconnection Cost Due Diligence.** Supplier has conducted due diligence regarding the costs of all facilities and equipment necessary to interconnect the Facility to and at the Delivery Points and all such costs are covered by payments for Product provided for in this Agreement.

25.8 **Required Facility Documents.** All Required Facility Documents are listed on Exhibit 12. Pursuant to the Required Facility Documents, Supplier holds as of the Effective Date, or will hold by the Commercial Operation Date (or such other later date as may be specified under requirements of Law), and will maintain for the Term all Required Facility Documents (including all material authorizations, rights and entitlements) necessary to construct, own, operate and maintain the Facility and to perform its obligations under this Agreement, including the sale and delivery of Product to Buyer in accordance with this Agreement. The anticipated use of the Facility complies with all applicable restrictive covenants affecting the Facility or the Project Site.

25.9 **Governmental Approvals.** Supplier has applied or will apply for or has received the Governmental Approvals listed in Exhibits 10 and 12, and no other Governmental Approvals are required by Supplier to construct, own, operate and maintain the Facility or perform its obligations under this Agreement. Following the Commercial Operation Date, Supplier shall notify Buyer of any additional material Governmental Approvals that are required for the ownership, operation and maintenance of the Facility or the performance by Supplier of its obligations under
this Agreement, in each case, promptly after Supplier makes any such determination.

25.10 Related Agreements. Supplier has entered into or will enter into all material agreements as listed in Exhibit 12 necessary for the construction, ownership, operation and maintenance of the Facility and the performance of its obligations under this Agreement.

25.11 Certification. Subject to Section 3.5, the Generating Facility qualifies as a Renewable Energy System and Supplier has been and is in compliance with all requirements set forth in the Renewable Energy Law.

25.12 Title. Supplier will own all Product attributable to the Facility and has the right to sell such Product to Buyer. Supplier will convey good title to the Product to Buyer free and clear of any liens or other encumbrances or title defects, including any which would affect Buyer’s ownership of any portion of such Product or prevent the subsequent transfer of any portion of such Product by Buyer to a third party.

25.13 Project Execution Plan. Supplier will execute the development and construction of the Facility in accordance with the project execution plan submitted by Supplier to Buyer pursuant to the October 16, 2018 request for proposals, but subject to modifications as may be required to reflect changes in contractors and suppliers, subject to Section 25.14, and modifications as may be required to reflect the final design of the Facility, subject to Section 8.7. Supplier shall not make any material modifications to the project execution plan without the consent of Buyer, such consent not to be unreasonably withheld, conditioned or delayed.

25.14 Approved Vendors. To the extent the Facility uses equipment types listed on Exhibit 23, Supplier shall construct the Facility using only such equipment manufactured by the vendors, subcontractors and equipment suppliers listed on Exhibit 23, which shall be provided by Buyer.

25.15 Work Site Agreement. Supplier shall enter into a work site agreement, memorandum of understanding, or similar document in the form attached hereto as Exhibit 21.

25.16 Continuing Nature of Representations and Warranties; Notice. The representations and warranties set forth in this Article 25 are made as of the Effective Date and shall be deemed repeated as of the Commercial Operation Date. If at any time during the Term, Supplier obtains actual knowledge of any fact, circumstance, event or information that would have caused or cause any of the representations and warranties in this Article 25 to be materially untrue or misleading at the time given or deemed given or at any time thereafter for so long as this Agreement is in force and effect, then Supplier shall provide Buyer with written notice of the fact, circumstance, event or information, the representations and warranties affected, and the action, if any, which Supplier intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section 25.16 shall
be given as soon as practicable after Supplier obtains actual knowledge of any such fact, circumstance, event or information.

26. REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer represents and warrants to Supplier as of the Effective Date as follows and covenants to Supplier that such representations and warranties will be true and correct for so long as this Agreement is in force and effect:

26.1 Organization; Qualification. Buyer is a corporation duly organized, validly existing and in good standing under the Laws of the State of Nevada and has all requisite corporate power and authority to own, lease, and operate its properties and to carry on its business as is now being conducted. Buyer is duly qualified or licensed to do business and is in good standing in each jurisdiction in which the property owned, leased or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not reasonably be expected to have a Material Adverse Effect on Buyer.

26.2 Authority. Buyer has full authority to execute, deliver and perform its obligations under this Agreement and to consummate the transactions contemplated herein and has taken all corporate actions necessary to authorize the execution, delivery and performance of its obligations under this Agreement. No other proceedings or approvals on the part of Buyer are necessary to authorize this Agreement. This Agreement constitutes a legal, valid and binding obligation of Buyer enforceable in accordance with its terms except as the enforcement thereof may be limited by (a) applicable bankruptcy, insolvency or similar Laws affecting the enforcement of creditors’ rights generally and (b) general principles of equity, whether considered in a proceeding in equity or at law.

26.3 Governmental Approvals; No Violation. Other than obtaining Buyer’s Required Regulatory Approvals as set out in Exhibit 9, the execution, delivery and performance of its obligations under this Agreement by Buyer shall not: (a) conflict with or result in any breach of any provision of the articles of organization (or other similar governing documents) of Buyer; (b) require any Governmental Approval, except: (i) where the failure to obtain such Governmental Approval would not reasonably be expected to have a Material Adverse Effect on Buyer; or (ii) for Governmental Approvals which become applicable to Buyer as a result of specific regulatory status of Buyer or as a result of any other facts that specifically relate to the business or activities in which Buyer is or proposes to be engaged, which Governmental Approvals have been obtained or made by Buyer; or (c) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, agreement, lease or other instrument or obligation to which Buyer or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained.
26.4 Continuing Nature of Representations and Warranties: Notice. The representations and warranties set forth in this Article 26 are made as of the Effective Date. If at any time during the Term, Buyer obtains actual knowledge of any fact, circumstance, event or information that would have caused or cause any of the representations and warranties in this Article 26 to be materially untrue or misleading at the time given or at any time thereafter for so long as this Agreement is in force and effect, Buyer shall provide Supplier with prompt written notice of the fact, circumstance, event or information, the representations and warranties affected, and the action, if any, which Buyer intends to take to make the representations and warranties true and correct.

27. INSURANCE

27.1 General Requirements. From and after the Effective Date, Supplier shall maintain at all times, at its own expense, general-commercial liability, worker’s compensation, and other forms of insurance relating to its property, operations and facilities in the manner and amounts set forth in this Article 27. Supplier shall maintain coverage on all policies written on a “claims made” or “occurrence” basis. If any policy is maintained on a “claims made” form and is converted to an “occurrence form,” the new policy shall be endorsed to provide coverage back to a retroactive date acceptable to Buyer.

27.2 Qualified Insurers. Every contract of insurance providing the coverage required herein shall be with an insurer or eligible surplus lines insurer qualified to do business in the State of Nevada and with the equivalent, on a continuous basis, of an “A.M. Best Company Rating” of “A” or better and shall include provisions or endorsements:

27.2.1 Stating that such insurance is primary insurance with respect to the interest of Buyer and that any insurance maintained by Buyer is excess and not contributory insurance required hereunder;

27.2.2 Stating that no reduction, cancellation or non-renewal of the policy shall be effective until thirty (30) days from the date notice thereof is actually received by Buyer; provided that upon Supplier’s receipt of any notice of reduction, cancellation or non-renewal, Supplier shall immediately provide notice thereof to Buyer;

27.2.3 Providing Buyer with subrogation waivers on all coverage;

27.2.4 Providing for Separation of Insured coverage in the general liability and auto liability insurance policies; and

27.2.5 Naming Buyer as an additional insured on the general liability and auto liability insurance policies of Supplier as its interests may appear with respect to this Agreement.
27.3 **Certificates of Insurance.** Within thirty (30) days of the Effective Date and each anniversary thereafter during the Term, and upon any change in coverage or at the request of Buyer (not to exceed once each year), Supplier shall provide to Buyer properly executed and current certificates of insurance with respect to all insurance policies required to be maintained by Supplier under this Agreement. Certificates of insurance shall provide the following information:

27.3.1 The name of insurance company, policy number and expiration date;

27.3.2 The coverage required and the limits on each, including the amount of deductibles or self-insured retentions, which shall be for the account of Supplier; and

27.3.3 A statement indicating that Buyer shall receive at least thirty (30) days prior notice of cancellation or non-renewal of a policy or of a reduction of liability limits with respect to a policy.

27.4 **Certified Copies of Insurance Policies.** At Buyer's request, in addition to the foregoing certificates of insurance, Supplier shall deliver to Buyer a copy of each insurance policy, certified as a true and complete copy by an authorized representative of the issuing insurance company.

27.5 **Inspection of Insurance Policies.** Buyer shall have the right to inspect the original policies of insurance applicable to this Agreement at Supplier's place of business during regular business hours.

27.6 **Supplier's Minimum Insurance Requirements.**

27.6.1 **Worker's Compensation.** Workers' compensation insurance in the form and manner required by statutory requirements and endorsement providing insurance for obligations under the U.S. Longshoremen's and Harbor Worker's Compensation Act and the Jones Act where applicable. Employer's liability insurance with the following limits: (a) one million dollars ($1,000,000.00) per each bodily injury by accident; (b) one million dollars ($1,000,000.00) per each employee bodily injury by occupational disease; and (c) one million dollars ($1,000,000.00) in the annual aggregate per each bodily injury by occupational disease.

27.6.2 **General Liability.** General liability insurance including bodily injury, property damage, products/completed operations, contractual and personal injury liability with a combined single limit of at least five million dollars ($5,000,000) per occurrence and at least five million dollars ($5,000,000) annual aggregate.

27.6.3 **Automobile Liability.** Automobile liability insurance including owned, non-owned and hired automobiles with combined bodily injury and property damage with a combined single limit of at least two million dollars ($2,000,000). The minimum insurance limits set forth in Sections 27.6.1,
27.6.2, and 27.6.3 can be met by Supplier’s underlying workers’ compensation/employer’s liability, general liability, and automobile liability policies in combination with an excess insurance policy.

27.6.4 **Excess Liability.** Excess liability insurance with a minimum limit of five million dollars ($5,000,000) (“Excess Minimum”) for each occurrence and an aggregate where applicable on a following form basis to be excess of the insurance coverage and limits required in Supplier’s general liability insurance and automobile liability insurance. Supplier shall promptly notify Buyer if the Excess Minimum is not available and Supplier shall purchase additional insurance coverage up to the Excess Minimum if required by Buyer.

27.6.5 **Failure to Comply.** If Supplier fails to comply with the provisions of this Article 27, Supplier shall save harmless and indemnify Buyer from any direct or indirect Loss, including attorneys’ fees and other costs of litigation, resulting from the injury or death of any person or damage to any property if Buyer would have been protected had Supplier complied with the requirements of this Article 27, in accordance with the indemnification provisions of Article 18.

28. NO EXPECTATION OF CONFIDENTIALITY; PUBLIC STATEMENTS

28.1 **No Expectation of Confidentiality.** Supplier has no expectation that any of the terms of this Agreement will be treated as confidential by Buyer, and Buyer has no obligation to seek confidential treatment of this Agreement in connection with Buyer’s Required Regulatory Approvals or otherwise.

28.2 **Public Statements.** The Parties shall consult with each other prior to issuing any public announcement, public statement or other public disclosure with respect to this Agreement and Supplier shall not issue any such public announcement, public statement or other public disclosure without having first received the written consent of Buyer, except as may be required by Law. Notwithstanding the foregoing, Supplier acknowledges and agrees that Buyer may advertise, issue brochures or make other announcements, publications or releases regarding this Agreement and the Facility for educational, promotional or informational purposes and Supplier may disclose this Agreement and information regarding the Facility to its members, officers, directors, employees, suppliers, contractors, attorneys, agents and representatives in connection with the execution, delivery and performance of its obligations under this Agreement. Supplier shall reasonably cooperate with Buyer regarding such activities, including providing Buyer with reasonable access to the Facility and authorizing the use of pictures of the Facility for such activities. It shall not be deemed a violation of this Section 28.2 to file this Agreement with the PUCN or FERC or any other Governmental Authority in connection with Buyer’s Required Regulatory Approvals, Supplier’s Required Regulatory Approvals or otherwise.
29. MISCELLANEOUS

29.1 Notices.

29.1.1 All notices, requests, demands, submittals, waivers and other communications required or permitted to be given under this Agreement (each, a “Notice”) shall, unless expressly specified otherwise, be in writing and shall be addressed, except as otherwise stated herein, to the Parties’ Contract Representatives as set forth in Exhibit 4, as the same may be modified from time to time by Notice from the respective Party to the other Party.

29.1.2 All Notices required by this Agreement shall be sent by regular first class U.S. mail, registered or certified U.S. mail (postage paid return receipt requested), overnight courier delivery, or electronic mail. Such Notices will be effective upon receipt by the addressee, except that Notices transmitted by electronic mail shall be deemed to have been validly and effectively given on the day (if a Business Day and, if not, on the next following Business Day) on which it is transmitted if transmitted before 16:00 PPT, and if transmitted after that time, on the following Business Day. If any Notice sent by regular first class U.S. mail, registered or certified U.S. mail postage paid return receipt requested, or overnight courier delivery is tendered to an addressee and the delivery thereof is refused by such addressee, then such Notice shall be deemed validly and effectively given upon such tender. All oral notifications required under this Agreement shall be made to the receiving Party’s Contract Representative or Operating Representative (as applicable) and shall promptly be followed by Notice as provided in this Section 29.1.

29.1.3 Notices of Force Majeure or an Event of Default pursuant to Article 20 or Article 24, respectively, and Notices of a change to Exhibit 4 shall be sent either by registered or certified U.S. mail (postage paid return receipt requested), overnight courier delivery or electronic mail. If any such Notice is sent via electronic mail, then a copy of such Notice shall also be sent either by registered or certified U.S. mail (postage paid return receipt requested), or overnight courier delivery. Such Notices will be effective as provided in Section 29.1.2.

29.1.4 Any payments required to be made to a Party under this Agreement shall be made pursuant to the payment instructions in Exhibit 4, as such payment instructions may be amended by such Party from time to time by Notice to the other Party.

29.2 Merger. This Agreement contains the entire agreement and understanding between the Parties with respect to all of the subject matter contained herein, thereby merging and superseding all prior agreements and representations by the Parties with respect to such subject matter contained herein whether written or oral.
29.3 **Counterparts.** This Agreement may be executed in multiple counterparts, each of which shall be deemed an original.

29.4 **Rules of Construction; Interpretation.** Unless otherwise required by the context in which any term appears: (a) the singular includes the plural and vice versa; (b) references to “Articles,” “Sections,” “Schedules,” or “Exhibits” are to articles, sections, schedules, or exhibits hereof; (c) all references to a particular Person include a reference to such Person’s permitted successors and assigns; (d) ”herein,” “hereof” and “hereunder” refer to this Agreement as a whole; (e) all accounting terms not specifically defined herein shall be construed in accordance with generally accepted accounting principles, consistently applied; (f) the masculine includes the feminine and neuter and vice versa; (g) “including” (and the correlative terms “include”, “includes” and “included”) means “including, without limitation” or “including, but not limited to”; (h) all references to a particular Law means that Law as amended, supplemented or otherwise modified from time to time; (i) all references to energy or capacity are to be interpreted as utilizing alternating current, unless expressly stated otherwise; and (j) the word “or” is not necessarily exclusive. Reference to “days”, “months”, “quarters” and “years” shall be to calendar days, months, quarters and years, unless expressly stated otherwise herein. In the event an ambiguity or question of intent or interpretation arises with respect to this Agreement, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any Law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise.

29.5 **Headings and Titles.** The headings and section titles in this Agreement are for convenience of the Parties only and shall not be used to construe this Agreement.

29.6 **Discontinued or Modified Index.** If any index publisher discontinues publishing or substantially modifies any index utilized herein, then the index used herein will be modified to the most appropriate available index, with appropriate adjustments to take into account any changes in the location of measurement.

29.7 **Severability.** If any term, provision or condition of this Agreement is held to be invalid, void or unenforceable by a Governmental Authority and such holding is subject to no further appeal or judicial review, then such invalid, void, or unenforceable term, provision or condition shall be deemed severed from this Agreement and all remaining terms, provisions and conditions of this Agreement shall continue in full force and effect. The Parties shall endeavor in good faith to replace such invalid, void or unenforceable terms, provisions or conditions with valid and enforceable provisions which achieve the purpose intended by the Parties to the greatest extent permitted by Law.

29.8 **Waivers; Remedies Cumulative.** No failure or delay on the part of a Party in exercising any of its rights under this Agreement or in insisting upon strict performance of provisions of this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing, usage of trade or
course of performance between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith. The remedies provided in this Agreement are cumulative and not exclusive of any remedies provided by Law or in equity. Notwithstanding the foregoing or any other provision hereof, for breach of any provision hereof for which an express remedy or measure of damages is provided (including Sections 3.4 (Delivery Responsibilities), 3.5 (Renewable Energy System), 3.6 (Shortfall; Replacement Costs), 3.7 (PC Shortfall; PC Replacement Costs), 8.4 (Failure to Achieve Commercial Operation), 8.5 (Delay Damages), 8.6 (Nameplate Damages) and 8.7 (Modification)), such express remedy or measure of damages will be the sole and exclusive remedy, the obligor’s liability will be limited as set forth in such provision and all other remedies or damages at law or in equity are waived, unless the provision in question provides that the express remedies are in addition to other remedies that may be available.

29.9 Amendments. Amendments or modifications to this Agreement must be in writing and executed by an authorized representative of each Party. Buyer may determine that submitting an amendment or modification to this Agreement to the PUCN and FERC, as applicable, for filing, acceptance or approval shall be a condition precedent to the effectiveness of any such amendment.

29.10 Time is of the Essence. Time is of the essence to this Agreement and in the performance of all of the covenants, agreements, obligations and conditions hereof.

29.11 Choice of Law. This Agreement and the rights and obligations of the Parties hereunder shall be construed and governed by the Laws of the State of Nevada, except for such Laws that would require the application of the Laws of another jurisdiction.

29.12 Further Assurances. The Parties agree to execute and deliver promptly, at the expense of the Party requesting such action, any and all other and further instruments, documents and information which a Party may request and which are reasonably necessary or appropriate to give full force and effect to the terms and intent of this Agreement. Without limiting the foregoing, whenever revised or updated exhibits are delivered or generated hereunder for attachment to this Agreement, the Parties will memorialize the same in a reasonable written instrument, to be executed and delivered by both Parties.

29.13 Forward Contract. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereunder constitute a “forward contract” within the meaning of the United States Bankruptcy Code.

29.14 No Third-Party Beneficiaries. Nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, and this Agreement is intended
solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder.

29.15 Specific Performance.

29.15.1 Subject always to Section 29.15.2 (a) Buyer shall be entitled to seek and obtain a decree compelling specific performance or granting injunctive relief with respect to, and shall be entitled, to enjoin any actual or threatened breach of any material obligation of Supplier hereunder, (b) the Parties agree that specific performance (including temporary and preliminary relief) and injunctive relief are proper in the event of any actual or threatened breach of any material obligation of Supplier hereunder, and that any liability limits contained herein shall not operate to limit the exercise of Buyer’s remedies in equity to cause Supplier to perform its obligations hereunder, and (c) Supplier agrees that it will not assert as a defense to Buyer’s action for specific performance of, or injunctive relief relating to, Buyer’s obligations hereunder that the amounts payable or paid by Supplier in respect of liquidated damages constitute an adequate remedy for the breach of such obligation, and Supplier hereby conclusively waives such defense. Supplier shall at all times during the Term, own, lease, control, hold in its own name or be signatory to (as the case may be) all assets relating to the Facility to the extent necessary to prevent a material adverse effect on Buyer’s right to specific performance or injunctive relief.

29.15.2 Buyer shall not be entitled to seek and obtain a decree compelling specific performance or granting injunctive relief for Supplier’s breach of any provision hereof for which an express remedy or measure of damages is provided (including Sections 3.4 (Delivery Responsibilities), 3.5 (Renewable Energy System), 3.6 (Shortfall; Replacement Costs), 3.7 (PC Shortfall; PC Replacement Costs), 8.4 (Failure to Achieve Commercial Operation), 8.5 (Delay Damages), and 8.6 (Nameplate Damages)).


[SIGNATURES APPEAR ON THE FOLLOWING PAGE]
IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representative as of the Effective Date.

BUYER:
NEVADA POWER COMPANY d/b/a NV ENERGY

By: [Signature]
Name: Douglas A. Cannon
Title: President

SUPPLIER:
SOLAR PARTNERS XI, LLC

By: [Signature]
Name: David Scaysbrook
Title: Managing Partner
EXHIBIT 1

DESCRIPTION OF FACILITY

1. Name of Generating Facility: Gemini Solar
   (a) Location: Clark County, Nevada
   (b) Delivery Points: 230kv Crystal Substation, and
   525kv South Crystal (Navajo) Substation

2. Supplier: Solar Partners XI, LLC

3. Parent: Valley of Fire Solar, LLC

4. Operator: Supplier

5. Equipment:
   (a) Type of Generating Facility: Photovoltaic solar
   (b) Installed Nameplate Capacity:
      (i) Total capacity: 745.6 MVA (sum of inverter rating)
      (ii) Expected Nameplate Capacity Rating at Delivery Points: 690 MW AC @ +/- 0.95, subject to the provisions of Section 3.4.5 (gross nameplate of 707 MW with software-controlled limit to achieve 690 MW at Delivery Points)
      (iii) Total gross output capacity: 745.6 MW
      (iv) Total capacity net of Station Usage and other losses: 690 MW (at Delivery Points)
      (v) Full Requirements Period Capacity Factor: 65%
      (vi) Full Requirements Period Product: 206,310 MWh over each Full Requirements Period

   (c) Additional Technology Specific Information, if any:

6. Operating Characteristics of Generating Facility during Generating Facility-Only Generation:
   (a) Max VAR, leading: 226.8 MVAR (@delivery of 690 MW at Delivery Points)
   (b) Max VAR, lagging: 226.8 MVAR (@delivery of 690 MW at Delivery Points)
   (c) Power Factor: +/- 0.95, subject to the provisions of Section 3.4.5
   (d) Controlled Ramp Rate: <10 second to rated capacity or as specified by inverter manufacturer
   (e) Minimum Operating Capacity (MW): 10 MW, provided, however that any interval in which the dispatch is less than 34.5 MW will be excluded from the calculation of the Dispatchable Accuracy Rate pursuant to Exhibit 16

7. Operating Characteristics of Generating Facility during Storage Facility Discharge:
   (a) Max VAR, leading: 124.9 MVAR (@delivery of 380 MW at the Delivery Points from Storage Facility)
   (b) Max VAR, lagging: 124.9 MVAR (@delivery of 380 MW at the Delivery Points from Storage Facility)
DESCRIPTION OF FACILITY

(c) Power Factor: +/- 0.95, subject to the provisions of Section 3.4.5
(d) Controlled Ramp Rate: <10 second to 380 MVA (real/reactive power to be limited to Storage capacity at Delivery Points/4)
(e) Minimum Operating Capacity (MW): 10 MW, provided, however that any interval in which the dispatch is less than 34.5 MW will be excluded from the calculation of the Dispatchable Accuracy Rate pursuant to Exhibit 16

8. Type of Storage Facility: (e.g. AC or DC coupled, technology, chemistry, etc.)
   (a) DC-coupled Battery System

9. Operating Characteristics of Storage Facility available to Buyer:
   (a) Charge capacity at the Storage Facility Metering Points on DC side: 400 MW
   (b) Discharge capacity at Delivery Points: 380 MW
   (c) Discharge capacity at the Delivery Points for a 3.7-hour duration: 380 MW as of COD
   (d) Storage capacity at Delivery Points: 1,416 MWh as of COD
   (e) Projected Storage capacity at Delivery Point by contract year [%]

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<th>Year</th>
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<td>Year 1</td>
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<td>Year 2</td>
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<td>Year 24</td>
<td>103.6%</td>
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<tr>
<td>Year 25</td>
<td>102.5%</td>
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</table>
EXHIBIT 2A

PRODUCT RATES

DISPATCHABLE PERIOD PRODUCT RATE

The Dispatchable Period Product Rate shall be $24.79 per MWh.

FULL REQUIREMENTS PERIOD PRODUCT RATE

The Full Requirements Period Product Rate during the Full Requirements Period shall be 6.5 times the Dispatchable Product Rate for the applicable period (the “Full Requirements Period Product Rate”) as represented below.

|     | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|-----|---|---|---|---|---|---|---|---|---|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Jan | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Feb | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Mar | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Apr | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| May | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Jun | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Jul | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Aug | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Sep | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Oct | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Nov | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
| Dec | x | x | x | x | x | x | x | x | x | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  | x  |
EXHIBIT 2B
FORM OF MONTHLY ENERGY INVOICE

Supplier Letterhead

Facility: ______________________ Date: ____________
Facility ID: ____________________ Billing Period: ___________

Invoice Number: ____________

CURRENT MONTHLY BILLING DATA INPUT

Pricing
Dispatchable Period Product Rate
Full Requirements Period Product Rate
Provisional Product Rate
Test Product Rate
Over Delivery Amount Rate

$/MWh

Excused Product
Planned Outages
Force Majeure
Emergencies (as applicable)
Curtailed Product
Un-Dispatched Amount
Transmission Provider Instructions
Buyer’s Failure to Accept Net Energy
FRP Deemed Delivered Energy

Total Excused Product

Delivered Amount (kWh) On-Peak Off-Peak
Dispatchable Period – Net Energy
Full Requirements Period – Net Energy
Total Delivered Amount

CURRENT MONTHLY INVOICE CALCULATION

<table>
<thead>
<tr>
<th>Description</th>
<th>Net Energy</th>
<th>Rate/kWh</th>
<th>Amount</th>
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<tbody>
<tr>
<td>a. Dispatchable Period Product</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>b. Full Requirements Period Product</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>c. FRP Deemed Delivered Energy</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>d. Un-Dispatched Amount</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>e. Provisional Energy</td>
<td>_______</td>
<td>x _______</td>
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<tr>
<td>f. Test Energy</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>g. Shortfall/Replacement Cost (from page 2B-2)</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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<tr>
<td>h Over Delivery Amount</td>
<td>_______</td>
<td>x _______</td>
<td>$ _______</td>
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</table>

i. Total Product Payment (a+b+c+d+e+f-g+h) $ _______

j. Adjustments (+/-) $ _______

TOTAL AMOUNT DUE (i + j) $ _______

PAYMENT DUE DATE NO LATER THAN: ____________

1 Excluding Provisional Energy and Test Energy

2B-1
**EXHIBIT 2B**

**FORM OF MONTHLY ENERGY INVOICE**

**REPLACEMENT COST CALCULATION** – For Billing Period: ________________

<table>
<thead>
<tr>
<th>Full Requirements Period</th>
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<tbody>
<tr>
<td>a. Full Requirements Period Product</td>
</tr>
<tr>
<td>b. 95% of FRP Product (0.95 * a)</td>
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<tr>
<td>c. Excused Product</td>
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<tr>
<td>d. Delivered Amount</td>
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<tr>
<td>e. Reserved</td>
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</table>

**Shortfall (Y/N)?**

- __________

| f. Shortfall Amount (max b – c – d or zero)                                             | ________________ kWh |

**Replacement Cost Calculation**

| g. Average Market Price                                                                  | ________________ $/MWh |
| h. Full Requirements Period Product Rate                                                | ________________ $/MWh |
| i. Difference (max g – h or zero)                                                       | ________________ $/MWh |

| j. Replacement Cost (f * i)                                                             | $ ________________ |

**REPLACEMENT COST CALCULATION** – For Billing Period: ________________

<table>
<thead>
<tr>
<th>Dispatchable Period</th>
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<tbody>
<tr>
<td>k. Resource-Adjusted Backcast Amount</td>
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<tr>
<td>l. FRP Charging Energy</td>
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<tr>
<td>m. Difference (k – l)</td>
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<tr>
<td>n. 95% of Difference (0.95 * m)</td>
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</table>

| o. Delivered Amount                                                                     | ________________ kWh |
| p. Excused Product                                                                      | ________________ kWh |

**Shortfall (Y/N)?**

- __________

| r. Shortfall Amount (max n – o – p or zero)                                             | ________________ kWh |

**Replacement Cost Calculation**

| s. Average Market Price                                                                  | ________________ $/MWh |
| t. Dispatchable Period Product Rate                                                     | ________________ $/MWh |
| u. Difference (max s – t or zero)                                                       | ________________ $/MWh |

| v. Replacement Cost (r * u)                                                             | $ ________________ |
EXHIBIT 2B

FORM OF MONTHLY ENERGY INVOICE DETAIL

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<th>Date</th>
<th>Hour Ending</th>
<th>On-Peak/Off-Peak</th>
<th>Dispatched Availability Amount</th>
<th>Total Delivered Amount</th>
<th>Base Product Amount</th>
<th>Product Rate</th>
<th>Full Requirements Period Delivered Amount</th>
<th>Un-Dispatched Amount</th>
<th>Base Product Cost</th>
<th>Excess Energy</th>
<th>Maximum Amount Energy</th>
<th>Excused Product</th>
<th>Reason for Excused Product</th>
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Total On-Peak: 
Total Off-Peak: 
TOTAL: 

2B-3
**EXHIBIT 2C**

**FORM OF PC REPLACEMENT INVOICE**

Buyer Letterhead

---

**Facility:** __________________________
**Facility ID:** __________________________
**Date:** __________
**Contract Year:** __________
**Invoice Number:** __________
**Payment Due Date:** __________

**PC REPLACEMENT COSTS CALCULATION**

**Contract Year Data**

<table>
<thead>
<tr>
<th>PCs</th>
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<tbody>
<tr>
<td>a. Yearly PC Amount</td>
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<tr>
<td>b. Delivered PCs</td>
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**PCs Associated with Excused Product:**

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<th>PCs</th>
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<td>c. Planned Outages</td>
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<td>d. Force Majeure</td>
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<td>e. Emergencies</td>
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<td>f. Curtailed Product</td>
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<tr>
<td>g. Un-Dispatched Amount</td>
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<tr>
<td>h. Transmission Provider Instructions</td>
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<tr>
<td>i. Buyer’s Failure to Accept Net Energy</td>
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<tr>
<td>j. FRP Deemed Delivered Energy</td>
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<tr>
<td>k. Excused Product</td>
<td>(c + d + e + f + g + h + i + j)</td>
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<tr>
<td>l. Difference (a - k)</td>
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<tr>
<td>m. 90% of Difference (0.9 * l)</td>
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**n. PC Shortfall Amount (max m - b or zero)**

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<tr>
<td>o. PC Replacement Rate</td>
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<tbody>
<tr>
<td>p. PC REPLACEMENT COSTS (n * o)</td>
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</table>
EXHIBIT 3A

DESCRIPTION OF PROJECT SITE

All Project Site is located on BLM Lands. The following property intersect the Project Site, in Clark County, Nevada:
Block A
- Section 13, Township 17 South, Range 64 East
- Northeast 1/6, Section 14, Township 17 South, Range 64 East
- Southeast 3/4, Section 12, Township 17 South, Range 64 East
- Southwest 1/2, Section 7, Township 17 South, Range 65 East
- Northwest 1/2, Section 18, Township 17 South, Range 65 East
- Southwest 1/3, Section 18, Township 17 South, Range 65 East

Consisting of approximately 862 acres.
Block B
- Southeast 1/2, Northeast 1/3, Section 7, Township 17 South, Range 65 East
- Northeast, Southwest, Southeast 1/3, Section 8, Township 17 South, Range 65 East
- Northeast 1/2, Southeast 1/2, Section 18, Township 17 South, Range 65 East
- Northwest, Southwest, Southeast, Northeast 2/3, Section 17, Township 17 South, Range 65 East
- Northwest 1/5, Southwest 1/2, Southeast, Northeast, Section 19, Township 17 South, Range 65 East
- Northwest, Southwest, Northeast 1/2, Section 19, Township 17 South, Range 65 East
- Northeast 1/6, Southeast 1/3, Section 20, Township 17 South, Range 65 East
- Northwest, Southwest, Northeast 1/2, Southeast 2/3, Section 30, Township 17 South, Range 65 East
- Northwest 2/3, Southeast, Section 36, Township 17 South, Range 64 East
- Northwest, Southwest 1/2, Northeast 1/3, Section 31, Township 17 South, Range 65 East
- Northwest 1/2, Northeast 2/3, Section 31, Township 18 South, Range 64 East

Consisting of approximately 3340 acres.
Block C
- Northeast, Southeast 2/3, Section 8, Township 17 South, Range 65 East
- Northeast, Southwest 2/3, Section 9, Township 17 South, Range 65 East
- Northeast 1/4, Section 17, Township 17 South, Range 65 East
- Northwest 1/3, Section 16, Township 17 South, Range 65 East

Consisting of approximately 472 acres.
Block D
- Southwest 1/4, Southeast 1/4, Section 20, Township 17 South, Range 65 East
- Northwest 1/2, Northeast 1/2, Southwest 3/4, Southeast 3/4, Section 29, Township 17 South, Range 65 East
- Northwest, Northeast 3/4, Southwest, Southeast, Section 32, Township 17 South, Range 65 East
- Northeast 1/3, Southeast 3/4, Section 31, Township 17 South, Range 65 East
- Section 05 3/4, Section 06 1/8, Section 04 1/8 Township 18 South, Range 65 East

Consisting of approximately 1913 acres.
Block E
- Southeast 1/5, Section 20, Township 17 South, Range 65 East
- Southwest 1/5, Section 21, Township 17 South, Range 65 East
- Northeast 1/4, Southeast 1/8, Section 29, Township 17 South, Range 65 East
- Northwest 2/3, Southwest 3/4, Section 28, Township 17 South, Range 65 East
- Northwest 1/2, Section 33, Township 17 South, Range 65 East

Consisting of approximately 402 acres.
EXHIBIT 3A

DESCRIPTION OF PROJECT SITE

Gen-tie parcels (3 options):

- Southwest, Southeast, Section 10, Township 17 South, Range 64 East
- Southwest, Southeast, Section 11, Township 17 South, Range 64 East
- Southwest, Northwest, Northeast Section 12, Township 17 South, Range 64 East
- Northwest, Northeast, Section 07, Township 17 South, Range 64 East
- Northwest, Northeast, Section 15, Township 17 South, Range 64 East
- Northwest, Northeast, Southeast, Section 14, Township 17 South, Range 64 East
- Southeast, Southwest, Section 13, Township 17 South, Range 64 East
- Southwest, Section 18, Township 17 South, Range 65 East
- Northwest, Section 19, Township 17 South, Range 65 East
EXHIBIT 4
NOTICES, BILLING AND PAYMENT INSTRUCTIONS

SUPPLIER:

Solar Partners XI, LLC

<table>
<thead>
<tr>
<th>Contact</th>
<th>Mailing Address</th>
<th>Phone</th>
<th>E-mail</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mark Boyadjian</td>
<td>c/o Valley of Fire LLC</td>
<td>917-653-8116</td>
<td><a href="mailto:Mark@areviapower.com">Mark@areviapower.com</a></td>
</tr>
<tr>
<td></td>
<td>500 N. Central Ave Suite 600 Glendale, CA, 91203</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Prior to Commercial Operation Date:

From and after Commercial Operation Date:

<table>
<thead>
<tr>
<th>David Scaysbrook</th>
<th>c/o Valley of Fire LLC</th>
</tr>
</thead>
<tbody>
<tr>
<td>15 Via Roma Suite 1.303, Isle of Capri, QLD 4217 Australia</td>
<td>61 400 439 590</td>
</tr>
</tbody>
</table>

OPERATING REPRESENTATIVE:

Prior to Commercial Operation Date:

From and after Commercial Operation Date:

<table>
<thead>
<tr>
<th>David Scaysbrook</th>
<th>c/o Valley of Fire LLC</th>
</tr>
</thead>
<tbody>
<tr>
<td>15 Via Roma Suite 1.303, Isle of Capri, QLD 4217 Australia</td>
<td>61 400 439 590</td>
</tr>
</tbody>
</table>

CHARGING AND DISCHARGING NOTICE COMMUNICATIONS:

[To be provided prior to start of construction]

OPERATING NOTIFICATIONS:

[To be provided prior to start of construction]

Prescheduling
Real-Time
Monthly Checkout
EXHIBIT 4

NOTICES, BILLING AND PAYMENT INSTRUCTIONS

INVOICES:
Mark Boyadjian  c/o Valley of Fire LLC  917-653-8116  Mark@areviapower.com
500 N. Central Ave Suite 600 Glendale,
CA, 91203

PAYMENT INSTRUCTIONS  [To be provided by Supplier]

BUYER: NV ENERGY

Nevada Power Company d/b/a NV Energy

<table>
<thead>
<tr>
<th>Contact</th>
<th>Phone</th>
<th>E-mail</th>
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<tr>
<td>CONTRACT REPRESENTATIVE:</td>
<td>702/402-5667</td>
<td><a href="mailto:ContractManagement@nvenergy.com">ContractManagement@nvenergy.com</a></td>
</tr>
<tr>
<td>Manager, Energy Supply</td>
<td>702/402-5667</td>
<td><a href="mailto:ContractManagement@nvenergy.com">ContractManagement@nvenergy.com</a></td>
</tr>
<tr>
<td>Contract Management</td>
<td>702/402-5667</td>
<td><a href="mailto:ContractManagement@nvenergy.com">ContractManagement@nvenergy.com</a></td>
</tr>
<tr>
<td>6226 W Sahara Ave, M/S 26A</td>
<td>702/402-5667</td>
<td><a href="mailto:ContractManagement@nvenergy.com">ContractManagement@nvenergy.com</a></td>
</tr>
<tr>
<td>Las Vegas, NV 89146</td>
<td>702/402-5667</td>
<td><a href="mailto:ContractManagement@nvenergy.com">ContractManagement@nvenergy.com</a></td>
</tr>
</tbody>
</table>

OPERATING REPRESENTATIVES

- Scheduling
  - Portfolio Analytics-NPC (Normal Business Hours) 702/402-2882  PortfolioAnalytics@nvenergy.com
  - Portfolio Analytics-SPPC (Normal Business Hours) 702/402-2884  PortfolioAnalytics@nvenergy.com
  - Generation Dispatch (Control Area Operations) 702/402-7111  Sysop@nvenergy.com
  - Daily Availability Notice-NPC (Spreadsheet) 702/402-2882  PortfolioAnalytics@nvenergy.com
  - Daily Availability Notice-SPPC (Spreadsheet) 702/402-2884  PortfolioAnalytics@nvenergy.com

- Emergencies (including Force Majeure)
  - Grid Reliability 775/834-4216  Grid_Reliability@nvenergy.com
  - Portfolio Analytics 702/402-1954  PortfolioAnalytics@nvenergy.com

- Planned Outages-NPC
  702/402-6602  esccoc@nvenergy.com

- Planned Outages-SPPC
  775/834-4716  esccoc@nvenergy.com

- Metering-NPC
  702/402-6110  NPCMeterOps@nvenergy.com

- Metering-SPPC
  775/834-7156  Electric_Meter_Ops_North@nvenergy.com

INVOICES
Energy Supply Contract Management 702/402-5667  ContractManagement@nvenergy.com
6226 W Sahara Ave, M/S 26A
Las Vegas, NV 89146

CC all invoices to:
Fuel & Purchased Power Accounting 775/834-6281  cmcelwee@nvenergy.com
6100 Neil Road, M/S S2A20
Reno, NV 89511

“EVENT OF DEFAULT”, “COMMERCIAL OPERATION DATE” AND “FORCE MAJEURE”
CC all notices to:
Office of General Counsel
6226 W. Sahara Ave, M/S 3A
Las Vegas, NV 89146
EXHIBIT 5
ONE-LINE DIAGRAM OF FACILITY AND DELIVERY POINT

Attached is a one-line diagram of the Facility, which indicates the Delivery Points and the ownership and the location of Meters, including the Storage Facility Metering Points.
EXHIBIT 6

PROJECT MILESTONE SCHEDULE

1. All time periods are in months after the last day of the month in which the PUCN Approval Date (designated as “AA” below). Any other timing is as otherwise described in specific items below. Buyer will update this Exhibit 6 with actual dates after the PUCN Approval is received.

2. All milestones may be completed earlier than stated times, at the sole option of Supplier.

A) **Project Milestone:** Supplier shall issue Limited Notices to Proceed (LNTPs) for equipment and initial construction-related activities.

   **Completion Date:** later of thirty-five (37) months AA or September 30, 2022

   **Documentation:** Supplier shall provide Buyer a copy of the executed LNTP acknowledged by the Construction Contractor and documentation from qualified professionals which indicates that equipment is planned to be procured. Such documentation will also indicate the type of initial construction-related activities and physical work that has begun at the Project Site.

B) **Project Milestone:** Supplier shall obtain all Required Facility Documents to construct the Facility.

   **Completion Date:** later of forty-one (41) months AA or January 31, 2023.

   **Documentation:** Supplier shall provide Buyer with an officer’s certificate from an authorized representative of Supplier certifying that the Required Facility Documents to construct the Facility as listed in Exhibit 12 (Construction Documents) have been obtained, together with the metering system design for the Facility (submitted for Buyer’s approval in accordance with Section 7.1) and a completed version of Exhibit 14.

C) **Project Milestone:** Supplier’s major equipment shall be delivered to the Project Site

   **Completion Date:** later of forty-three (43) months AA or March 31, 2023.

   **Documentation:** Supplier shall provide Buyer with documentation that the major equipment (including step-up and medium voltage transformers [and inverters]) has been delivered to the Project Site.

D) **Project Milestone:** Supplier shall obtain the Required Facility Documents to operate (but not achieve Commercial Operation) the Facility, including registration with PC Administrator.

   **Completion Date:** later of fifty-one (51) months AA or November 30, 2023.

   **Documentation:** Supplier shall provide Buyer with an officer’s certificate from an authorized representative of Supplier certifying that Required Facility Documents to operate (but not achieve Commercial Operation) the Facility as listed in Exhibit
EXHIBIT 6

PROJECT MILESTONE SCHEDULE

12 have been obtained, together with reasonable documentation evidencing registration with PC Administrator.

E) Project Milestone: The Facility achieves the Operation Date.

Completion Date: later of (51) months AA or November 30, 2023.

Documentation: Buyer’s Meters shall record Energy being delivered from the Generating Facility to Buyer and the Storage Facility and Discharging Energy being delivered from the Storage Facility to Buyer, and Supplier provides written notice to Buyer that the Facility satisfies the definition of Operation Date.

CRITICAL PROJECT MILESTONES

F) Project Milestone: Supplier shall demonstrate to Buyer that it has complete financing for construction of the Facility.

Completion Date: later of forty-two (42) months AA or February 28, 2023.

Documentation: Supplier shall provide Buyer with an officer’s certificate from an authorized Representative of Supplier certifying that debt and equity financing arrangements have been executed for funding of 100% of the construction financing of the Facility.

G) Project Milestone: Notice to Proceed has been issued to the Construction Contractor under the Construction Contract and construction of the Facility has commenced.

Completion Date: later of forty-two (42) months AA or February 28, 2023.

Documentation: Supplier shall provide Buyer a copy of the executed Notice to Proceed acknowledged by the Construction Contractor and documentation from qualified professionals which indicates that physical work has begun at the Project Site regarding the construction of the Facility, as well as an ALTA Survey for the Project Site. Supplier shall provide Buyer with a copy of the Construction Contract.

H) Project Milestone: The Facility achieves the Commercial Operation Date.

Completion Date: the 1st day of the month following the later of fifty-two (52) months AA or December 1, 2023 (“Commercial Operation Deadline”).

Documentation: Supplier provides certifications required by Section 8.3.2 to Buyer.
EXHIBIT 7

PERFORMANCE TESTS

1. Performance tests required by the Construction Contract.

2. Such other tests as may be required by Law or by Buyer to document resource supply.
**EXHIBIT 8**

**FORM OF AVAILABILITY NOTICE**

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<thead>
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<th>Unit Name</th>
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</tbody>
</table>

Describe any Generating Facility impairments including cause and expected return to full availability ("NA" if none):

Describe any Storage Facility charging impairments including cause and expected return to full availability ("NA" if none):

Describe any Storage Facility discharging impairments including cause and expected return to full availability ("NA" if none):

Storage Facility state of charge:__________

Note: Form of Availability Notice to be provided by Buyer to Supplier in Excel format. The format of the form may not be changed, except by Buyer.²

² NTD: Exhibit 8 to accommodate relevant information with respect to the Storage Facility.
**EXHIBIT 8**

**FORM OF AVAILABILITY NOTICE**

Date For Notice:  

Supplier:  

Name of Suppliers Representative:  

Buyer: Nevada Power Company  

Contact Info:  

<table>
<thead>
<tr>
<th>Hour</th>
<th>Net Availability From Plant MWh</th>
<th>Total Derating MWh</th>
<th>Plant Total MWh</th>
<th>Cause and Time of Derating (include whether any derating impacts ability to charge or discharge the Storage Facility)</th>
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Include other considerations current or anticipated events potentially impacting the Generating Facility’s ability to produce the Delivered Amount or Ancillary Services including any Supplier plans to charge the battery.

Note: Supplier to submit Form of Availability Notice in Excel format to Balancing Authority Area Operator as identified in Exhibit 4 Notices. Form requires 7 days of availability.
EXHIBIT 9

BUYER’S REQUIRED REGULATORY APPROVALS

1. PUCN Approval of this Agreement.
EXHIBIT 10

SUPPLIER’S REQUIRED REGULATORY APPROVALS

1. Renewable Energy System certification as specified in WREGIS.

2. PUCN Approval of this Agreement.

3. Although obtaining EWG status is not a Supplier Required Regulatory Approval, if Supplier elects to obtain EWG status for the Facility, Supplier shall obtain: (a) a Notice of Self Certification as an EWG, or (b) an order from FERC granting the Facility EWG status.

4. Market-Based-Rate Authority based on Supplier’s status as a “public utility” under the Federal Power Act, FERC authorization under section 205 of the Federal Power Act to make sales of electric energy, capacity, and ancillary services from the Facility.

5. U.S. Energy Information Administration, filing of Forms 860 and 923

6. Environmental Impact Statement (EIS) and associated Record of Decision (ROD) issued by Bureau of Land Management (BLM) under the National Environmental Protection Act (NEPA)

7. Bureau of Land Management, right of way grant(s) issued pursuant to the Federal Land Policy Management Act

8. U.S. Fish and Wildlife Service, Endangered Species Act, Section 7 Consultation and Biological Opinion

9. State Historical Preservation Office, National Historical Preservation Act, Section 106 Consultation

10. Clean Water Act Section 404, Jurisdictional Determination, Nation Wide Permit or Individual Permit if applicable

11. Clean Water Act, Section 401, state way quality certification, if required in connection with other permits

12. Public Utilities Commission Nevada, Utility Environmental Protection Act, order and permit to construct

13. Nevada Division of Environmental Protection, Construction Water General Permit

14. Clark County Department of Planning, Special Use Permit (SUP)

15. Clark County Department of Air Quality, Dust Control Permit

16. Clark County Building Department, Construction Permits
EXHIBIT 11

TECHNICAL SPECIFICATIONS

In accordance with Section 8.1, Supplier shall provide, not later than Supplier’s completion of the Project Milestone relating to obtaining Required Facility Documentation (Section (B) of Exhibit 6), a completed version of Exhibit 11.
EXHIBIT 12

REQUIRED FACILITY DOCUMENTS

Construction Documents

1. Construction Contract
2. Construction Permits
3. This Agreement
4. Permits and approvals listed as items 6 through 16 on Exhibit 10

Operating Documents

1. Permits and approvals listed as items 1 through 5 on Exhibit 10
2. PUCN Approval of this Agreement.
3. Operating and Maintenance Agreement.
4. Interconnection Agreement
5. California Energy Commission, Renewable Portfolio Standard Pre-Certification and Certification, if applicable.
6. Western Renewable Energy Generation Information System (WREGIS), registrations, including as a Nevada Renewable Energy System, as applicable.
7. Transmission Provider’s permission to operate.
8. Crossing consents or easements, Nevada Department of Transportation (NDOT), Union Pacific Rail Road (UPRR) and other utility crossings, as applicable
### EXHIBIT 13A

**DISPATCH AVAILABILITY AMOUNT**

The Dispatch Availability Amount shall be the Energy amounts for each Delivery Hour that shall be made available by Supplier to Buyer, pursuant to this Agreement, as specified by each value in the table below.

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**Daily Dispatch Availability Amount (MWh)**

- 3,994
- 5,014
- 6,214
- 6,925
- 7,701
- 8,154
- 7,487
- 7,172
- 6,760
- 5,690
- 4,465
- 3,583

**Daily On-Peak Dispatch Availability Amount (MWh)**

- 3,994
- 5,014
- 6,213
- 6,871
- 7,506
- 7,855
- 7,328
- 7,096
- 6,741
- 5,690
- 4,465
- 3,583

**Monthly Dispatch Availability Amount (MWh)**

- 123,815
- 140,385
- 192,624
- 207,750
- 238,728
- 244,624
- 232,104
- 222,318
- 202,813
- 176,400
- 133,963
- 111,058

**Annual Dispatch Availability Amount (MWh)**

- 2,226,581

**Delivery Points Maximum Amount (MWh)**

- 690.0
### PERFORMANCE PERIODS

(Dispatchable Period, Full Requirements Period and Full Requirements Period Product)

The Dispatchable Period, the Full Requirements Period and the Full Requirements Period Product\(^3\) are identified in the table below.\(^4\)

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Full Requirements Period Product (annual total)\(^5\): 206,310 MWh

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3 The hourly megawatt values stated in this table are for illustrative purposes only, which represents the estimated average hourly Net Energy deliveries during the hours of the Full Requirements Period. Supplier shall be required to deliver a total quantity of megawatt-hours during the Full Requirements Period, which is the sum of the megawatts delivered during all hours of the Full Requirements Period, the Full Requirements Period Product.

4 The hourly values in the table are an average of the complete Full Requirement Period and have been rounded to a single decimal point for each Delivery Hour in the Full Requirements Period.

5 Full Requirements Period Product equals (the sum of June output hours ending 1700-2100 multiplied by 30) + (the sum of July output hours ending 1700-2100 multiplied by 31) + (the sum of August output hours ending 1700-2100 multiplied by 31).
EXHIBIT 14

DIAGRAM OF FACILITY

In accordance with Section 8.1, Supplier shall provide: (a) not later than Supplier’s completion of the Project Milestone relating to obtaining Required Facility Documentation (Section 2(B) of Exhibit 6), a completed version of Exhibit 14; and (b) within thirty (30) Business Days after the Commercial Operation Date, a revised version of Exhibit 14 reflecting the Facility as built.

The diagram of the Facility to be attached as Exhibit 14 will include a detailed layout of the Facility, including size, type, location and electrical infrastructure.
EXHIBIT 15

OPERATIONS AND MAINTENANCE AGREEMENT;
OPERATOR GOOD STANDING CERTIFICATE

In accordance with Section 8.9, Supplier shall provide Exhibit 15 no later than ninety (90) days prior to the Commercial Operation Date.
EXHIBIT 16

DISPATCHABLE ACCURACY RATE

For purposes of determining whether the Generating Facility remains capable of being dispatched by the Buyer, the ability of the Generating Facility to timely reach output levels sent by the Energy Management System to the Facility’s Automatic Generation Control system will be tracked at five minute intervals during the Dispatchable Period.

1. The Generating Facility’s Dispatchable Accuracy Rate during the Dispatchable Period will be calculated as follows:
   a. Determine the absolute value of the difference between the output level sent by Buyer’s Energy Management System (which shall not exceed the instantaneous maximum capability of the Generating Facility as communicated electronically from Supplier to Buyer) to the Facility’s Automatic Generation Control and the Delivered Amount (excluding any Buyer Charging Energy delivered to the Storage Facility Metering Points) of the Facility, as recorded and tracked at five minute intervals by Buyer;
   b. During an interval that includes a ramp from one set point to another, the comparison described in Section 1a of this Exhibit 16 will be made between the average of the start and finish output levels sent by Buyer’s Energy Management System (which shall not exceed the instantaneous maximum capability of the Generating Facility) to the Facility’s Automatic Generation Control and the Delivered Amount (excluding any Buyer Charging Energy delivered to the Storage Facility Metering Points);
   c. Divide this difference by the output level sent by the Buyer’s Energy Management System;
   d. Subtract this quotient from 1.00.
   For example: If Automatic Generation Control signal was 50MW and Facility Delivered Amount was 48MW. Therefore\(^6\): \(a = 2\), \(c = 2/50 = 0.04\), \(d = 1.0 - 0.04 = 0.96\), which expressed as a percentage is 96%.

2. Each calendar month, the Facility’s average Dispatchable Accuracy Rate during the Dispatchable Period will be calculated as follows:
   a. Sum each recorded five minute interval difference between the output level sent by the EMS to the Facility’s AGC and the actual output of the Facility as described above (for purposes of summation, treat all differences, whether positive or negative, as positive values);
   b. Sum each five minute recorded output level sent by the EMS to the Facility’s AGC;
   c. Divide the summed difference by the summed output level sent by the Facility’s EMS to the Facility’s AGC;
   d. Subtract this quotient from 1.00;
   e. This difference represents the Facility’s average Dispatchable Accuracy Rate for the calendar month.

3. Those periods in which the Facility is in a planned outage or wholly or partially unavailable due to Force Majeure, Emergencies, Transmission Provider Instructions or curtailment and therefore unable to follow dispatch orders shall be excluded for calculation of Dispatchable Accuracy Rate.

4. Real-Time and/or Instantaneous Availability of Supplier’s Generating Facility

\(^6\) Where a, b and c represent the above concepts.
EXHIBIT 16

DISPATCHABLE ACCURACY RATE

a. On an ongoing basis, the Generating Facility will provide real-time, instantaneous availability levels of minimum real power that could be generated at the referenced meter (pMinimum) and maximum real power that could be generated at the referenced meter (pMaximum). The pMinimum and pMaximum shall be reported at least once per six seconds as an estimated forecast.

b. Power set-point instructions from Buyer’s EMS to the Generating Facility’s AGC will recognize and obey real-time, instantaneous pMinimum and pMaximum availability levels, and any other constraints which are caused due to real-time weather conditions. In the event the Power set-point instructions from Buyer’s EMS to the Generating Facility’s AGC are lower than the instantaneous PMaximum, then Section 10.2.2 shall apply.

c. The Dispatchable Accuracy Rate will therefore be an indication of how the Generating Facility performed relative to its real-time or instantaneous capabilities as a result of existing weather and site conditions.

5. The difference between the set-point sent by the Buyer’s Energy Management System and the Delivered Amount from the Facility shall be considered zero for purposes of calculating the Dispatchable Accuracy Rate under the following conditions:

a. Those periods in which the Generating Facility is in a planned outage or affected by a force outage or Force Majeure or Emergency and therefore unable to follow dispatch orders shall be excluded for calculation of Dispatchable Accuracy Rate.

b. Those periods when the Buyer’s Energy Management System is not sending the Generating Facility a dispatch command.

c. The actual available solar generation is less than the estimated pMaximum forecast during the five minute set-point.

d. The 12 seconds following the receipt of an AGC signal for required response time of the Facility.

e. Those periods when the ramp rate of the Buyer’s AGC exceeds 10% per minute of the Expected Nameplate Capacity Rating as reported in Exhibit 1, Section 5(b)(ii) during the 5 minute dispatch period.

f. The referenced meter is the Delivery Point for the Generating Facility’s AGC set-point but the Storage Facility is given a charge/discharge notice.

g. Frequency response, Volt-Watt or other operating set-points are triggered that require the Storage Facility to charge or discharge something other than the AGC set-point.

h. Those periods when the Power set-point instructions from Buyer’s EMS to the Generating Facility’s AGC are higher than the instantaneous PMaximum.
EXHIBIT 17

FORM OF LETTER OF CREDIT

IRREVOCABLE STANDBY LETTER OF CREDIT

[Name of Issuing Bank]  
Letter Of Credit No. [_______]  
Irrevocable Standby Letter Of Credit

[Address of Issuing Bank]  
Stated Expiration Date: [_______]

[City, State of Issuing Bank]  
Stated Amount: USD $[_______]

Date of Issue: [_______], 20__

Applicant:  
[Name and address]

[_______]

[_______]

Beneficiary:  
Nevada Power Company d/b/a NV Energy
6226 W. Sahara Avenue
Las Vegas, NV 89146
Attn: Jenny Venter – Risk Control
Mailstop 9A

Credit Available With: [_______]
EXHIBIT 17

FORM OF LETTER OF CREDIT

Ladies and Gentlemen:

At the request and for the account of [ ] (the “Applicant”), we hereby establish in favor of Nevada Power Company (“Beneficiary”) for the aggregate amount not to exceed [ ] million United States Dollars ($[ ]), in connection with the Long Term Renewable Power Purchase Agreement dated as of [ ] (as amended, restated, amended and restated or otherwise modified, the “Agreement”), by and between the Applicant and Beneficiary this Irrevocable Standby Letter of Credit no. [ ] (this “Letter of Credit”) expiring on [date not earlier than 364 days from issuance] (the “Stated Expiration Date”).

We irrevocably authorize you to draw on this Letter of Credit, in accordance with the terms and conditions hereinafter set forth, in any amount up to the full Available Amount (as defined below) available against presentation of a dated drawing request drawn on [Name of Issuing Bank] manually signed by a purported authorized representative of a Beneficiary completed in the form of Annex 1 hereto (a “Drawing Request”). Partial drawings and multiple drawings are allowed under this Letter of Credit. Each Drawing Request honored by us shall immediately reduce the amount available to be drawn hereunder by the amount of the payment made in satisfaction of such Drawing Request (each, an “Automatic Reduction”).

On any given date, the Stated Amount (as set forth on the first page of this Letter of Credit) minus any Automatic Reductions plus any amounts increased pursuant to the terms and conditions hereto shall be the aggregate amount available hereunder (the “Available Amount”).

Drawing Requests and all communications with respect to this Letter of Credit shall be in writing, addressed or presented in person to us at: [Address of Issuing Bank], Attn: [ ], referencing this Letter of Credit No. [ ]. In addition, presentation of a Drawing Request may also be made by facsimile transmission to [Fax number of Issuing Bank], or such other facsimile number identified by us in a written notice to you. To the extent a Drawing Request is made by facsimile transmission, you must (i) provide telephone notification to us at [Telephone number of Issuing Bank] prior to or simultaneously with the sending of such facsimile transmission and (ii) send the original of such Drawing Request to us by overnight courier, at the same address provided above; provided, however, that our receipt of such telephone notice or original documents shall not be a condition to payment hereunder. Presentation of the original of this Letter of Credit shall only be required for any drawing of the entire Available Amount.

If a Drawing Request is presented in compliance with the terms of this Letter of Credit to us at such address or facsimile number by 11:00 a.m., New York City time, on any Business Day (as defined below), payment will be made not later than the close of business, New York City time, on the following Business Day, and if such Drawing Request is so presented to us after 11:00 a.m., New York City time, on any Business Day, payment will be made on the second following Business Day not later than the close of business, New York City time on such following Business Day. Payment under this Letter of Credit shall be made in immediately available funds by wire transfer to such account as specified in the Drawing Request.
FORM OF LETTER OF CREDIT

As used in this Letter of Credit, “Business Day” means any day other than a Saturday, Sunday or other day on which commercial banks are authorized or required by Law to remain closed in the State of New York.

This Letter of Credit shall expire on the earliest to occur of (1) our receipt of written confirmation from a Beneficiary authorizing us to cancel this Letter of Credit accompanied by the original of this Letter of Credit; (2) the close of business, New York time, on the date (the “Early Expiration Date”) specified in a notice of early expiration in the form of Annex 2 hereto sent by us to the Beneficiary and the Applicant by courier, mail delivery or delivery in person or facsimile transmission and stating that this Letter of Credit shall terminate on such date, which date shall be no less than thirty (30) days after the date of such notice, with the Beneficiary remaining authorized to draw on us prior to such Early Expiration Date in accordance with the terms hereof; or (3) the Stated Expiration Date. It is a condition of this letter of credit that it shall be deemed automatically extended without an amendment for periods of one (1) year each beginning on the present expiry date hereof and upon each anniversary of such date, unless at least thirty (30) days prior to any such expiry date we have sent you written notice (the “Notice of Non-Renewal”) by certified mail or overnight courier service that we elect not to permit this Letter of Credit to be so extended beyond, and will expire on its then current expiry date. No presentation made under this Letter of Credit after such expiry date will be honored. To the extent a Notice of Non-Renewal has been provided to the Beneficiary and Applicant in accordance herewith, the Beneficiary are authorized to draw on us up to, in the aggregate, the full Available Amount of this Letter of Credit, by presentation to us, in the manner and at the address specified in the third preceding paragraph, of a Drawing Request completed in the form of Annex 1 hereto and sent and purportedly signed by a Beneficiary’s authorized representative.

This Letter of Credit is effective immediately.

In the event that a Drawing Request fails to comply with the terms of this Letter of Credit, we shall provide the Beneficiary prompt notice of same stating the reasons therefore and shall upon receipt of a Beneficiary’s instructions, hold any nonconforming Drawing Request and other documents at your disposal or return any non-conforming Drawing Request and other documents to the Beneficiary at the addresses set forth above by delivery in person or facsimile transmission. Upon being notified that the drawing was not effected in compliance with this Letter of Credit, a Beneficiary may attempt to correct such non-complying Drawing Request in accordance with the terms of this Letter of Credit.

This Letter of Credit sets forth in full the terms of our undertaking and this undertaking shall not in any way be modified, amended, limited or amplified by reference to any document, instrument or agreement referred to herein, and any such reference shall not be deemed to incorporate herein by reference any document, instrument, or agreement except for Drawing Requests and certificates. The foregoing notwithstanding, this Letter of Credit is subject to the rules of the “International Standby Practices 1998, International Chamber of Commerce, Publication No. 590” published by the Institute of International Banking Law and Practice (“ISPD 98”) and, as to matters not governed by ISP 98, shall be governed by and construed in accordance with the Laws of the State of New York.
EXHIBIT 17

FORM OF LETTER OF CREDIT

This Letter of Credit is transferable, only in its entirety and not in part, upon presentation to us, at our presentation office specified herein, of a signed transfer certificate in the form of Annex 3 accompanied by this original Letter of Credit and all amendments, if any, in which a Beneficiary irrevocably transfers to its successor or assign all of its rights hereunder, whereupon we will either issue a substitute letter of credit to such successor or assign or endorse such transfer on the reverse of this Letter of Credit. Transfers to designated foreign nationals are not permitted as being contrary to the U.S. Treasury Department or Foreign Assets Controls Regulations.

Any voluntary reduction hereunder shall be in the form of Annex 4 hereto.

All banking charges are for the account of the Applicant. All transfer fees are for the account of the Beneficiary.

All Drawing Requests under this Letter of Credit must bear the clause: “Drawn under [Name of Issuing Bank], Letter of Credit Number [_____] dated [________________].”

This Letter of Credit shall not be amended except with the written concurrence of [Name of Issuing Bank], the Applicant and the Beneficiary.

We hereby engage with you that a Drawing Request drawn strictly in compliance with the terms of this Letter of Credit and any amendments thereto shall be honored.

We irrevocably agree with you that any legal action or proceeding with respect to this Letter of Credit shall be brought in the courts of the State of New York in the County of New York or of the United States of America in the Southern District of New York. You and we irrevocably submit to the nonexclusive jurisdiction of such courts solely for the purposes of this Letter of Credit. You and we hereby waive to the fullest extent permitted by Law any objection either of us may now or hereafter have to the laying of venue in any such action or proceeding in any such court.

[Name of Issuing Bank]

Authorized signature
EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 1
[Letterhead of a Beneficiary]

Drawn under [insert name of Issuing Bank],
Letter of Credit Number [_______] dated [_________]

DRAWING REQUEST
[Date]

[name and address of Issuing Bank]

Ladies and Gentlemen:

The undersigned, a duly authorized representative of a Beneficiary hereby draws on [insert name of Issuing Bank], Irrevocable Standby Letter of Credit No. [_______] (the “Letter of Credit”) dated [__________] issued by you in favor of us. Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

In connection with this drawing, we hereby certify that:

A) This drawing in the amount of US$__________ is being made pursuant to the Letter of Credit;

[Use one or more of the following forms of paragraph B, as applicable, and include in this Drawing Request]

B-1) Beneficiary is authorized to make a drawing under this Letter of Credit in accordance with the terms of the Agreement applicable to Beneficiary.

or

B-2) The Letter of Credit will expire within thirty (30) days of the date of this Drawing Request pursuant to a Notice of Non-Renewal and the Applicant has failed to provide a replacement letter of credit from an acceptable credit provider and satisfying the requirements of the Agreement applicable to Beneficiary;

or

B-3) [insert name of Issuing Bank] has delivered an Early Expiration Notice and such Early Expiration Notice has not been rescinded and the Applicant has not replaced the Letter of Credit;

; and

C) You are directed to make payment of the requested drawing to:
EXHIBIT 17

FORM OF LETTER OF CREDIT

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ___ day of ________________.

[Beneficiary]

By: ____________________________
Name: __________________________
Title: __________________________

FORM OF LETTER OF CREDIT

ANNEX 2
NOTICE OF EARLY EXPIRATION
[Date]

[Beneficiary name and address]

Ladies and Gentlemen:

Reference is made to that Irrevocable Standby Letter of Credit No. [_____] (the “Letter of Credit”) dated [______] issued by [Issuing Bank] in favor of [______] (the “Beneficiary”). Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

This constitutes our notice to you pursuant to the Letter of Credit that the Letter of Credit shall terminate on [______, ____] [insert a date which is thirty (30) or more days after the date of this notice of early expiration] (the “Early Expiration Date”).

Pursuant to the terms of the Letter of Credit, the Beneficiary is authorized to draw (pursuant to one or more drawings), prior to the Early Expiration Date, on the Letter of Credit in an aggregate amount that does not exceed the then Available Amount (as defined in the Letter of Credit).

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ___ day of ____________________.

[ISSUING BANK]

By: __________________________
Name: _________________________
Title: __________________________

cc:

[Applicant name and address]
EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 3

REQUEST FOR TRANSFER OF LETTER OF CREDIT IN ITS ENTIRETY

[Name of Issuing Bank],

(Address)
[City, State]

Attn: Trade Services Department

Re: [Name of Issuing Bank], Irrevocable Standby Letter of Credit No. [___________]

For value received, the undersigned beneficiary hereby irrevocably transfers to:

NAME OF TRANSFEREE

ADDRESS OF TRANSFEREE

CITY, STATE/COUNTRY ZIP

(hereinafter, the “transferee”) all rights of the undersigned beneficiary to draw under above letter of credit, in its entirety.

By this transfer, all rights of the undersigned beneficiary in such Letter of Credit are transferred to the transferee and the transferee shall have the sole rights as beneficiary hereof, including sole rights relating to any amendments, whether increases or extensions or other amendments and whether now existing or hereafter made. All amendments are to be advised directly to the transferee without necessity of any consent of or notice to the undersigned beneficiary.

The original of such Letter of Credit and all amendments, if any, is returned herewith, and we ask you to endorse the transfer on the reverse thereof, and forward it directly to the transferee with your customary notice of transfer.

In payment of your transfer commission in amount equal to a minimum of $[_____] and maximum of $[______].

Select one of the following:

___ we enclose a cashier’s/certified check
___ we have wired funds to you through __________________ bank
___ we authorize you to debit our account # __________________ with you, and in addition thereto, we agree to pay you on demand any expenses which may be incurred by you in connection with this transfer
EXHIBIT 17

FORM OF LETTER OF CREDIT

We certify that this transfer request is not in violation of any federal or state laws and further confirm our understanding that the execution of this transfer request by you is subject to compliance with all legal requirements and related procedures implemented by your bank under applicable laws of the United States of America [and the jurisdiction of Issuing Bank].

Very truly yours,

[BENEFICIARY NAME]

________________________________________
Authorized Signature

The signature(s) of __________________________________ with title(s) as stated conforms to those on file with us; are authorized for the execution of such instrument; and the beneficiary has been approved under our bank's Customer Identification Program. Further, pursuant to Section 326 of the USA Patriot Act and the applicable regulations promulgated thereunder, we represent and warrant that the undersigned bank: (i) is subject to a rule implementing the anti-money laundering compliance program requirements of 31 U.S.C. section 5318(h); (ii) is regulated by a Federal functional regulator [as such term is defined in 31 C.F.R. section 103.120(a)(2)]; and (iii) has a Customer Identification Program that fully complies with the requirements of the regulations.

________________________________________
(Signature of Authenticating Bank)

________________________________________
(Name of Bank)

________________________________________
(Printed Name/Title)

(Date)

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this _____ day of ________________.

[Beneficiary name]

By: ____________________________
Name: _________________________
Title: _________________________

cc:
[insert name and address of Transferee]
[insert name and address of Applicant]
EXHIBIT 17
FORM OF LETTER OF CREDIT

ANNEX 4
VOLUNTARY REDUCTION REQUEST CERTIFICATE

[Date]

[insert name of Issuing Bank]
[insert address of Issuing Bank]

Ladies and Gentlemen:

Reference is made to that Irrevocable Standby Letter of Credit No. [_____] (the “Letter of Credit”) dated [_____] issued by you in favor of [_____] (the “Beneficiary”). Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

The undersigned, a duly authorized representative of the Beneficiary, having been so directed by [_____] (the “Applicant”), hereby requests that the Stated Amount (as such term is defined in the Letter of Credit) of the Letter of Credit be reduced by U.S.$[_____] to U.S.$[______].

We hereby certify that the undersigned is a duly authorized representative of the Beneficiary.

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ____ day of ________________.

[Beneficiary name]

By: __________________________
Name: ________________________
Title: _________________________

cc:

[Applicant name and address]
EXHIBIT 18

YEARLY PC AMOUNT

| Yearly PC Amount | 2,226,581 MWh |

18-1
EXHIBIT 19

FORM OF LENDERS CONSENT

This CONSENT AND AGREEMENT (this “Consent”), dated as of __________, 20__, is entered into by and among Nevada Power Company, a Nevada corporation, d/b/a NV Energy, acting in its merchant function capacity (together with its permitted successors and assigns, “NVE”), ____________, in its capacity as [Administrative Agent] for the Lenders referred to below (together with its successors, designees and assigns in such capacity, “Administrative Agent”), and ____________, a ____________ formed and existing under the Laws of the State of ____________ (together with its permitted successors and assigns, “Borrower”). Unless otherwise defined, all capitalized terms have the meaning given in the PPA (as hereinafter defined).

WHEREAS, Borrower intends to develop, construct, install, test, own, operate and use an approximately ___ MW solar-powered electric generating facility and integrated storage facility located ____________, known as the ____________ (the “Project”).

WHEREAS, in order to partially finance the development, construction, installation, testing, operation and use of the Project, Borrower has entered into that certain [Financing Agreement] dated as of ________ (as amended, amended and restated, supplemented or otherwise modified from time to time, the “Financing Agreement”), among Borrower, the financial institutions from time to time parties thereto (collectively, the “Lenders”), and Administrative Agent for the Lenders, pursuant to which, among other things, Lenders have extended commitments to make loans and other financial accommodations to, and for the benefit of, Borrower.

[WHEREAS, Borrower anticipates that, prior to the completion of construction of the Project, it will seek an additional investor (the “Tax Investor”) to make an investment in Borrower to provide additional funds to finance the operation and use of the Project.]

WHEREAS, Buyer and Borrower have entered into that certain Power Purchase Agreement, dated as of ____________ (collectively with all documents entered into in connection therewith that are listed on [Schedule A] attached hereto and incorporated herein by reference, as all are amended, amended and restated, supplemented or otherwise modified from time to time in accordance with the terms thereof and hereof, the “PPA”).

WHEREAS, pursuant to a security agreement executed by Borrower and Administrative Agent for the Lenders (as amended, amended and restated, supplemented or otherwise modified from time to time, the “Security Agreement”), Borrower has agreed, among other things, to assign, as collateral security for its obligations under the Financing Agreement and related documents (collectively, the “Financing Documents”), all of its right, title and interest in, to and under the PPA to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents.

NOW THEREFORE, for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be legally bound, the parties hereto hereby agree as follows:
SECTION 1. CONSENT TO ASSIGNMENT

NVE acknowledges the collateral assignment by Borrower of, among other things all of its right, title and interest in, to and under the PPA to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents, consents to an assignment of the PPA pursuant thereto, and agrees with Administrative Agent as follows:

(A) Administrative Agent shall be entitled (but not obligated) to exercise all rights and to cure any defaults of Borrower under the PPA, subject to applicable notice and cure periods provided in the PPA and Section 1(C) below. Upon receipt of notice from Administrative Agent, NVE agrees to accept such exercise and cure by Administrative Agent if timely made by Administrative Agent under the PPA and this Consent. Upon receipt of Administrative Agent’s written instructions, NVE agrees to make directly to Administrative Agent all payments to be made by NVE to Borrower under the PPA from and after NVE’s receipt of such instructions, and Borrower consents to any such action.

(B) NVE will not, without the prior written consent of Administrative Agent (such consent not to be unreasonably withheld), (i) cancel, terminate or suspend its performance under the PPA, (ii) consent to or accept any cancellation, termination or suspension thereof by Borrower, except as provided in the PPA and in accordance with subparagraph 1(C) hereof.

(C) NVE agrees to deliver duplicates or copies of all notices of default delivered by NVE under or pursuant to the PPA to Administrative Agent in accordance with the notice provisions of this Consent. NVE may deliver any such notices concurrently with delivery of the notice to Borrower under the PPA. Administrative Agent shall have: (a) the same period of time to cure the breach or default that Borrower is entitled to under the PPA plus an additional fifteen (15) days if such default is the failure to pay amounts to NVE which are due and payable by Borrower under the PPA, except that if NVE does not deliver the default notice to Administrative Agent concurrently with delivery of the notice to Borrower under the PPA, then as to Administrative Agent, the applicable cure period under the PPA shall begin on the date on which the notice is given to Administrative Agent, or (b) the later of the applicable cure period under the PPA or thirty (30) days from the date notice of default or breach is delivered to Administrative Agent to cure such default if such breach or default cannot be cured by the payment of money to NVE, so long as Administrative Agent continues to perform any monetary obligations under the PPA and all other obligations under the PPA are performed by Borrower or Administrative Agent or its designees or assignees. If possession of the Project is necessary to cure such breach or default, and Administrative Agent or its designees or assignees declare Borrower in default and commence foreclosure proceedings, Administrative Agent or its designees or assignees will be allowed a reasonable period to complete such proceedings but not to exceed ninety (90) days. NVE consents to the transfer of Borrower’s interest under the PPA to a Qualified Transferee upon enforcement of such security at a foreclosure sale by judicial or non-judicial foreclosure and sale or by a conveyance by Borrower in lieu of foreclosure and agrees that upon such foreclosure, sale or conveyance, NVE shall recognize such Qualified Transferee as the applicable party under the PPA (provided that such Qualified Transferee assumes the obligations of Borrower under the PPA). “Qualified Transferee” means a Person that is at least as financially and operationally qualified as Borrower and, at a minimum, (i) has a tangible net worth of at least seven million five hundred thousand dollars ($7,500,000) or provides adequate assurance in an amount and form
EXHIBIT 19

FORM OF LENDERS CONSENT

reasonably acceptable to Buyer and (ii) has (or agrees to contract with an operator who has) (x) at least three (3) years of experience operating a generating plant of at least 100 MW and of similar technology to the generating facility component of the Project and (y) at least two (2) years of experience operating a storage facility of at least 10 MW and of similar technology to the storage facility component of the Project. Subject to the terms herein, NVE shall execute and deliver, at the reasonable request of the Administrative Agent, all documents reasonably necessary or appropriate to implement this Consent, including to effect a foreclosure and transfer.

(D) Notwithstanding subparagraph 1(C) above, in the event that the PPA is rejected by a trustee or debtor-in-possession in any bankruptcy or insolvency proceeding, or if the PPA is terminated for any reason other than a default which could have been but was not cured by Administrative Agent or its designees or assignees as provided in subparagraph 1(C) above, and if, within forty-five (45) days after such rejection or termination, the Lenders or their successors or assigns shall so request, to the extent permitted by applicable law, NVE will enter into a new contract with a Qualified Transferee. Such new contract shall be on the same terms and conditions as the original PPA for the remaining term of the original PPA before giving effect to such termination, provided, however that such terms shall be modified to the extent NVE reasonably determines such modifications are necessary to comply with any laws, rules or regulations applicable to Borrower, NVE or Lender, including any state, and federal constitutions, statutes, rules, regulations, published rates, and orders of governmental bodies and all judicial orders, judgments and decrees (hereinafter “Applicable Law”) in effect at such time. Lenders or Administrative Agent shall cure or cause the cure of any payment defaults then existing under the original PPA prior to NVE entering into a new contract.

(E) In the event Administrative Agent, the Lenders or their designees or assignees elect to perform Borrower’s obligations under the PPA as provided in subparagraph 1(C) above or enter into a new contract as provided in subparagraph 1(D) above, the recourse of NVE against Administrative Agent, Lenders or their designees and assignees shall be limited to such parties’ interests in the Project, the Development Security and Operating Security required under the PPA, and recourse against the assets of any party or entity that assumes the PPA or that enters into such new contract. Nothing herein abrogates, and any Qualifying Assignee shall be subject to, NVE’s rights under Article 6 of the PPA.

(F) In the event a Qualified Transferee succeeds to Borrower’s interest under the PPA, Administrative Agent, the Lenders or their designees or assignees shall cure any then-existing payment and performance defaults under the PPA, except any performance defaults of Borrower itself which by their nature are not capable of being cured and do not impair NVE’s rights under the PPA. Administrative Agent, the Lenders and their designees or assignees shall have the right to assign the PPA or the new contract entered into pursuant to subparagraph 1(d) above to any Qualified Transferee to whom Borrower’s interest in the Project is transferred, provided that such transferee assumes the obligations of Borrower under the PPA. Upon such assignment, Administrative Agent and the Lenders and their designees or assignees (including their agents and employees, but excluding Borrower) shall be released from any further liability thereunder accruing from and after the date of such assignment.
SECTION 2. REPRESENTATIONS AND WARRANTIES

NVE, acting in its merchant function capacity (and therefore specifically excluding the knowledge of NVE, acting in its transmission function capacity ("NVE Transmission")), as to any of the matters stated below, and without imputation to NVE of any knowledge whatsoever relating to the NVE Transmission, whether as a result of information publicly posted to the open access same-time information system or otherwise), hereby represents and warrants that as of the date of this Consent:

(A) It (i) is a corporation duly formed and validly existing under the laws of the state of its organization, (ii) is duly qualified, authorized to do business and in good standing in every jurisdiction necessary to perform its obligations under this Consent, and (iii) has all requisite corporate power and authority to enter into and to perform its obligations hereunder and under the PPA, and to carry out the terms hereof and thereof and the transactions contemplated hereby and thereby;

(B) the execution, delivery and performance of this Consent and the PPA have been duly authorized by all necessary corporate action on its part and do not require any approvals, material filings with, or consents of any entity or person which have not previously been obtained or made;

(C) each of this Consent and the PPA is in full force and effect;

(D) each of this Consent and the PPA has been duly executed and delivered on its behalf and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms;

(E) the execution, delivery and performance by it of this Consent and the PPA, and the consummation of the transactions contemplated hereby, will not result in any violation of, breach of or default under any term of (i) its formation or governance documents, or (ii) any material contract or material agreement to which it is a party or by which it or its property is bound, or of any material Applicable Law presently in effect having applicability to it, the violation, breach or default of which could materially and adversely affect its ability to perform its obligations under this Consent;

(F) neither NVE nor, to NVE’s actual knowledge, any other party to the PPA, is in default of any of its obligations thereunder.

SECTION 3. NOTICES

All notices required or permitted hereunder shall be in writing and shall be effective (a) upon receipt if hand delivered, (b) upon telephonic verification of receipt if sent by facsimile and (c) if otherwise delivered, upon the earlier of receipt or three (3) Business Days after being sent registered or certified mail, return receipt requested, with proper postage affixed thereto, or by private courier or delivery service with charges prepaid, and addressed as specified below:

If to NVE:

[ ]

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FORM OF LENDERS CONSENT

[_________________________________________]
[_________________________________________]
Telephone No.: [_____________________________________
Telexcopy No.: [_____________________________________
Attn: [__________________________________________]

If to Administrative Agent:
[_________________________________________]
[_________________________________________]
Telephone No.: [_____________________________________
Telexcopy No.: [_____________________________________
Attn: [__________________________________________]

If to Borrower:
[_________________________________________]
[_________________________________________]
Telephone No.: [_____________________________________
Telexcopy No.: [_____________________________________
Attn: [__________________________________________]

Any party shall have the right to change its address for notice hereunder to any other location within the United States by giving thirty (30) days written notice to the other parties in the manner set forth above. Further, the Tax Investor shall be entitled to receive notices from NVE by providing written notice to NVE of Tax Investor’s address for notices. NVE’s failure to provide any notice to the Tax Investor shall not be a breach of this Consent.

SECTION 4. CONFIRMATION, TERMINATION, AMENDMENT AND GOVERNING LAW

NVE agrees to (a) confirm its continuing obligation hereunder in writing upon the reasonable request of (and at the expense of) Borrower, Administrative Agent, the Lenders or any of their respective successors, transferees or assigns. No termination, amendment, variation or waiver of any provisions of this Consent shall be effective unless in writing and executed by the parties hereto. This Consent shall be governed by the laws of the State of New York (without giving effect to the principles thereof relating to conflicts of law except Section 5-1401 and 5-1402 of the New York General Obligations Law).

SECTION 5. COUNTERPARTS

This Consent may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

SECTION 6. SEVERABILITY

In case any provision of this Consent, or the obligations of any of the parties hereto, shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining
provisions, or the obligations of the other parties hereto, shall not in any way be affected or impaired thereby.

SECTION 7. ACKNOWLEDGMENTS BY BORROWER.

Borrower, by its execution hereof, acknowledges and agrees that notwithstanding any term to the contrary in the PPA, NVE may perform as set forth herein and that neither the execution of this Consent, the performance by NVE of any of the obligations of NVE hereunder, the exercise of any of the rights of NVE hereunder, or the acceptance by NVE of performance of the PPA by any party other than Borrower shall (1) release Borrower from any obligation of Borrower under the PPA, (2) constitute a consent by NVE to, or impute knowledge to NVE of, any specific terms or conditions of the Financing Agreement, the Security Agreement or any of the other Financing Documents, or (3) constitute a waiver by NVE of any of its rights under the PPA. Borrower and Administrative Agent acknowledge hereby for the benefit of NVE that none of the Financing Agreement, the Security Agreement, the Financing Documents or any other documents executed in connection therewith alter, amend, modify or impair (or purport to alter, amend, modify or impair) any provisions of the PPA. Borrower shall have no rights against NVE on account of this Consent.

SECTION 8. JURY TRIAL WAIVER

THE PARTIES EACH HEREBY IRREVOCABLY WAIVE ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

IN WITNESS WHEREOF, the parties by their officers duly authorized, have duly executed this Consent as of the date first set forth above.

Nevada Power Company

By: ________________________________
Name: ______________________________
Title: ______________________________

__________________________,
a __________________________

By: ________________________________
Name: ______________________________
Title: ______________________________

__________________________,
as Administrative Agent for the Lenders
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FORM OF LENDERS CONSENT

[Borrower]

By: ______________________________
Name: ____________________________
Title: ____________________________
EXHIBIT 20

FORM OF GUARANTEE

This GUARANTEE (this “Guarantee”), dated as of ___________, 20__, is issued by Quinbrook Low Carbon Power Parallel Fund (US) LP, a limited partnership organized and existing under the laws of Delaware and Quinbrook Low Carbon Power LP, a limited partnership organized and existing under the laws of Jersey (“Guarantors”) in favor of Nevada Power Company, a Nevada corporation doing business as NV Energy (“Company”).

Pursuant to that certain Long-Term Renewable Power Purchase Agreement, dated as of __________, 20__ (as the same may be amended, modified or supplemented from time to time, the “Agreement”), by and between Company and [___________], a [_________] [___________], of which Guarantors are the indirect parent entities (“Subsidiary”), and pursuant to which Guarantors will indirectly benefit from the terms and conditions thereof, and the performance by Subsidiary of its obligations thereunder, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantors, jointly and severally, hereby covenant, undertake and agree with Company as follows:

Section 1. Definitions. Capitalized terms used herein and not otherwise defined shall have their respective meanings as set forth in the Agreement.

Section 2. Guarantee.

(a) Guarantee. Guarantors hereby, jointly and severally, irrevocably and unconditionally guarantee to and for the benefit of Company, the full and prompt payment by Subsidiary of each and every obligation of Subsidiary arising under the Agreement up to (i) twenty six million seven hundred fifty thousand ($26,750,000) prior to the PUCN Approval Date, (ii) seventy four million nine hundred thousand ($74,900,000) from and after the PUCN Approval Date until the Commercial Operation Date, and (iii) sixty eight million nine thousand five hundred dollars ($68,009,500) from and after the Commercial Operation Date (collectively, the “Cap”), including, without limitation, the payment of all indemnities, refunds and liquidated damages payable at any time under the Agreement (the “Guaranteed Obligations”). The Guaranteed Obligations shall further include, without limitation, interest accruing as part of the Guaranteed Obligations according to the terms thereof following the commencement by or against the Subsidiary of any case or proceeding under any Applicable Law relating to bankruptcy, insolvency, reorganization, winding-up, liquidation, dissolution or composition or adjustment of debt and (ii) all reasonable costs and expenses (including reasonable attorneys’ fees), if any, incurred by Company in enforcing Company’s rights under this Guarantee up to a one million dollar ($1,000,000) limit which is in addition to the Cap in each instance. Guarantors further agree that if Subsidiary shall fail to pay in full all or any part of the Guaranteed Obligations, Guarantors will pay (or procure the payment of) the same in accordance with Section 4 herein. Notwithstanding anything in this Guarantee or in the Agreement to the contrary, the maximum aggregate obligation and liability of Guarantors under this Guarantee, and the maximum recovery from Guarantors under this Guarantee, shall in no event exceed the Cap plus all reasonable costs and expenses (including reasonable attorneys’ fees), if any, incurred by Company in enforcing Company’s rights under this Guarantee up to a one million dollar ($1,000,000) limit; provided that Guarantors shall not be liable for such fees and expenses of Company under this Section 2(a) if it is finally determined by a court of competent jurisdiction that no payment under this Guarantee is due.

(b) Nature of Guarantee. The Guarantee and the obligations of Guarantors hereunder shall continue to be effective or be automatically reinstated, as the case may be, if at any time
EXHIBIT 20

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payment of any of the Guaranteed Obligations is rendered unenforceable or is rescinded or must otherwise be returned by Company upon the occurrence of any action or event including, without limitation, the bankruptcy, reorganization, winding-up, liquidation, dissolution or insolvency of the Subsidiary, Guarantors, any other Person or otherwise, all as though the payment had not been made.

(c) Absolute Guarantee. Guarantors agree that their obligations under this Guarantee are irrevocable, absolute, independent, unconditional and continuing and shall not be affected by any circumstance that constitutes a legal or equitable discharge of a guarantor or surety other than payment in full of the Guaranteed Obligations. In furtherance of the foregoing and without limiting the generality thereof, Guarantors agree, subject to the other terms and conditions hereof, as follows:

(i) this Guarantee is a guarantee of payment and not of collectability or performance;

(ii) Company may from time to time in accordance with the terms of the Agreement, without notice or demand and without affecting the validity or enforceability of this Guarantee or giving rise to any limitation, impairment or discharge of Guarantors' liability hereunder, (A) renew, extend, accelerate or otherwise change the time, place, manner or terms of payment of the Guaranteed Obligations, (B) settle, compromise, release or discharge, or accept or refuse any offer of payment with respect to, or substitutions for, the Guaranteed Obligations or any agreement relating thereto and/or subordinate the payment of the same to the payment of any other obligations, (C) request and accept other guaranties of or security for the Guaranteed Obligations and take and hold security for the payment of this Guarantee or payment of the Guaranteed Obligations, (D) release, exchange, compromise, subordinate or modify, with or without consideration, any security for payment of the Guaranteed Obligations, any other guarantees of the Guaranteed Obligations, or any other obligation of any person with respect to the Guaranteed Obligations, (E) enforce and apply any security now or hereafter held by or for the benefit of Company in respect of this Guarantee or the Guaranteed Obligations and direct the order or manner of sale thereof, or exercise any other right or remedy that Company may have against any such security, as Company in its discretion may determine consistent with the Agreement and any applicable security agreement, and even though such action operates to impair or extinguish any right of reimbursement or subrogation or any other right or remedy of Guarantors against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guarantee of or security for the Guaranteed Obligations, and (F) exercise any other rights available to Company under the Agreement, at law or in equity; and

(iii) this Guarantee and the obligations of Guarantors hereunder shall be valid and enforceable and shall not be subject to any limitation, impairment or discharge for any reason (other than payment in full of the Guaranteed Obligations and otherwise as set forth in this Guarantee), including, without limitation, the occurrence of any of the following, whether or not Guarantors shall have had notice or knowledge of any of them: (A) any failure to assert or enforce, or agreement not to assert or enforce, or the stay or enjoining, by order of court, by operation of law or otherwise, or the exercise or enforcement of, any claim or demand or any right, power or remedy with respect to the Guaranteed Obligations or any agreement relating thereto, or with respect to any other guarantee of or security for the payment of the Guaranteed Obligations; (B) any waiver, amendment or modification of, or any consent to departure from, any of the terms or provisions of the Agreement or any agreement or instrument executed pursuant thereto or of any
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other guarantee or security for the Guaranteed Obligations; (C) the Guaranteed Obligations, or any agreement relating thereto, at any time being found to be illegal, invalid or unenforceable in any respect; (D) the personal or corporate incapacity of any person; (E) any change in the financial condition, or the bankruptcy, administration, receivership or insolvency of Subsidiary or any other person, or any rejection, release, stay or discharge of Subsidiary’s or any other person’s obligations in connection with any bankruptcy, administration, receivership or similar proceeding or otherwise or any disallowance of all or any portion of any claim by Company, its successors or permitted assigns in connection with any such proceeding; (F) any change in the corporate existence of, or cessation of existence of, Guarantors or the Subsidiary (whether by way of merger, amalgamation, transfer, sale, lease or otherwise); (G) the failure to create, preserve, validate, perfect or protect any security interest granted to, or in favor of, any person; (H) any substitution, modification, exchange, release, settlement or compromise of any security or collateral for or guarantee of any of the Guaranteed Obligations or failure to apply such security or collateral or failure to enforce such guarantee; (I) the existence of any claim, set-off, or other rights which Guarantors or any affiliates thereof may have at any time against Company or any affiliate thereof in connection with any matter unrelated to the Agreement; and (J) any other act or thing or omission, or delay to do any other act or thing, which may or might in any manner or to any extent vary the risk of Guarantors as obligors in respect of the Guaranteed Obligations.

(d) **Currency.** All payments made by Guarantors hereunder shall be made in U.S. dollars in immediately available funds.

(e) **Defenses.** Notwithstanding anything herein to the contrary, each Guarantor specifically reserves to itself all rights, counterclaims and other defenses that the Subsidiary is or may be entitled to arising from or out of the Agreement, except for any defenses arising out of the bankruptcy, insolvency, dissolution or liquidation of the Subsidiary, the lack of power or authority of the Subsidiary to enter into the Agreement and to perform its obligations thereunder, or the lack of validity or enforceability of the Subsidiary’s obligations under the Agreement or any transaction thereunder.

Section 3. **Other Provisions of the Guarantee.**

(a) **Waivers by Guarantor.** Each Guarantor hereby waives for the benefit of Company, to the maximum extent permitted by Applicable Law:

(i) notice of acceptance hereof;

(ii) notice of any action taken or omitted to be taken by Company in reliance hereon;

(iii) any right to require Company, as a condition of payment by Guarantor, to (A) proceed against or exhaust its remedies against Subsidiary or any person, including any other guarantor of the Guaranteed Obligations, or (B) proceed against or exhaust any security held from Subsidiary or any person, including any other guarantor of the Guaranteed Obligations;

(iv) subject to Clause 2(e), any defense arising by reason of the incapacity, lack of authority or any disability of Subsidiary including, without limitation, any defense based on or arising out of the lack of validity or the unenforceability of the Guaranteed Obligations or any agreement or instrument relating thereto or by reason of the cessation of the liability of Subsidiary
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from any cause other than payment in full of the Guaranteed Obligations or termination of this Guarantee in accordance with its terms;

(v) any requirement that Company protect, secure, perfect or insure any security interest or lien on any property subject thereto;

(vi) other than as provided in Section 4, any requirement that Company be diligent or prompt in making demands hereunder or give notices of default under the Agreement, notices of any renewal, extension or modification of the Guaranteed Obligations or any agreement related thereto, and any right to consent to any thereof; and

(vii) any event, occurrence or other circumstance which might otherwise constitute a legal or equitable discharge of a surety, including promptness, diligence, notice of acceptance and notice of any default under the Agreement, notice of presentment, demand, protest, and notice of dishonor or nonpayment, notice of acceleration or other demand and any other notice with respect to this Guarantee.

(b) Deferral of Subrogation. Until such time as the Guaranteed Obligations have been paid or performed in full, notwithstanding any payment made by a Guarantor hereunder or the receipt of any amounts by Company with respect to the Guaranteed Obligations, (i) each Guarantor (on behalf of itself, its successors and assigns, including any surety) hereby expressly agrees not to exercise any right, nor assert the impairment of such rights, it may have to be subrogated to any of the rights of Company against Subsidiary or against any other collateral security held by Company for the payment of the Guaranteed Obligations, (ii) each Guarantor agrees that it will not seek any reimbursement from Company in respect of payments made by such Guarantor in connection with the Guaranteed Obligations or amounts realized by Company in connection with the Guaranteed Obligations and (iii) such Guarantor shall not claim or prove in a liquidation or other insolvency proceeding of the Subsidiary in competition with the Company. If any amount shall be paid to a Guarantor on account of such subrogation rights at any time when all of the Guaranteed Obligations shall not have been paid in full or otherwise fully satisfied, such amount shall be held in trust by such Guarantor for the benefit of Company and shall forthwith be paid to Company, to be credited and applied to the Guaranteed Obligations.

Section 4. Payment. If Subsidiary fails or refuses to pay any Guaranteed Obligation, Company shall notify Guarantors and Guarantors in writing of such failure to pay and demand that payment be made by Guarantors (a “Demand Notice”). Guarantors shall make the requested payment within five (5) Business Days of receipt of a Demand Notice.

Section 5. Representations and Covenants of Guarantors.

(a) Each Guarantor hereby represents as of the date hereof as follows:

(i) Guarantor is duly organized, validly existing and in good standing under the laws of its jurisdiction of organization, and has the corporate power, authority and legal right to own its property and assets and to transact the business in which it is engaged.

(ii) Guarantor has full power, authority and legal right to execute and deliver this Guarantee and all other instruments, documents and agreements required by the provisions of
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this Guarantee to be executed, delivered and performed by Guarantor, and to perform its obligations hereunder and thereunder.

(iii) The execution, delivery and performance of this Guarantee and all other instruments, documents and agreements required by the provisions of this Guarantee to be executed, delivered and performed by Guarantor have been duly authorized by all necessary action on the part of Guarantor and do not contravene or conflict with Guarantor’s governance documents.

(iv) This Guarantee and all other instruments, documents and agreements required by the provisions of this Guarantee to be executed, delivered and performed by Guarantor have been duly executed and delivered by Guarantor and constitute the legal, valid and binding obligations of Guarantor, enforceable against it in accordance with their respective terms.

(v) Neither the execution and delivery of this Guarantee nor the performance of the terms and conditions hereof by Guarantor shall result in (i) a violation or breach of, or a default under, or a right to accelerate, terminate or amend, any contract, commitment or other obligation to which Guarantor is a party or is subject or by which any of its assets are bound, or (ii) a violation by Guarantor of any Applicable Law.

(vi) To the actual knowledge of Guarantor, there are no actions, suits, investigations, proceedings, condemnations, or audits by or before any court or other governmental or regulatory authority or any arbitration proceeding pending or threatened against or affecting Guarantor, its properties, or its assets that would adversely affect its ability to perform under this Guarantee.

(vii) All necessary action has been taken under Applicable Laws to authorize the execution, delivery and performance of this Guarantee. No governmental approvals or other consents, approvals, or notices of or to any person are required in connection with the execution, delivery, performance by Guarantor, or the validity or enforceability, of this Guarantee.

(viii) That the obligations under this Guarantee do not exceed Undrawn Commitments (as such term is defined in the Limited Partnership Agreement of Quinbrook Low Carbon Power Parallel Fund (US) LP (the “LP”)) of the Guarantor.

(b) Each Guarantor hereby covenants:

(i) That so long as there are Undrawn Commitments (as such term is defined in the Limited Partnership Agreement of Quinbrook Low Carbon Power Parallel Fund (US) LP (the “LP”)) and this Guarantee is in effect, the Manager will not consent to a transfer of LP interests unless the transferee has the legal, financial and operating power, authority, capacity and assets to satisfy the obligations of the transferring LP in respect of the transferred interest. That the General Partner will not consent to any amendment to the LP that would adversely affect or otherwise impair the LP’s ability to satisfy its obligations under this Guarantee.

Section 6. Notices. All notices, demands, instructions, waivers, consents, or other communications required or permitted hereunder shall be in writing in the English language and shall be sent by personal delivery, courier, certified mail or facsimile, to the following addresses:
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(a) If to Guarantors:

Quinbrook Infrastructure Partners
1330 Post Oak Boulevard
Suite 1350
Houston, TX 77056
Attention: David Scaysbrook
Facsimile:

With a copy to (which shall not constitute notice):

Winston & Strawn LLP
1700 K Street, NW
Washington, DC 20006-3817
Attention: Patrick E. Groomes
Facsimile: [______________]

(b) If to Company:

Nevada Power Company
6226 W. Sahara Avenue
Las Vegas, Nevada 89146
Facsimile No.: 702-402-2455
Email: ContractManagement@nvenergy.com
Attn: [____________________]

With a copy to (which shall not constitute notice):

Nevada Power Company
6226 W. Sahara Avenue
Las Vegas, Nevada 89146
Facsimile: (702) 402-2069
Attn: [____________________]

The addresses and facsimile numbers of either party for notices given pursuant to this Guarantee may be changed by means of a written notice given to the other party at least three (3) Business Days (being a day on which clearing banks are generally open for business in the jurisdiction of the party to whom a notice is sent) prior to the effective date of such change. Any notice required or authorized to be given hereunder shall be in writing (unless otherwise provided) and shall be served (i) personally, (ii) by courier service or (iii) by facsimile transmission addressed to the relevant Person at the address stated below or at any other address notified by that Person as its address for service. Any notice so given personally shall be deemed to have been served on delivery, any notice so given by express courier service shall be deemed to have been served the next Business Day after the same shall have been delivered to the intended Person, and any notice so given by facsimile transmission shall be deemed to have been served on dispatch unless dispatched after the recipient’s normal business hours on a Business Day or dispatched on any day other than a Business Day, in which case such notice shall be deemed to have been delivered on
the next Business Day. As proof of such service it shall be sufficient to produce a receipt showing personal service, the receipt of a courier company showing the correct address of the addressee or an activity report of the sender’s facsimile machine showing the correct facsimile number of the Person on whom notice is served and the correct number of pages transmitted.


(a) Waiver: Remedies Cumulative. No failure on the part of Company to exercise, and no delay on the part of Company in exercising, any right or remedy, in whole or in part hereunder shall operate as a waiver thereof. No single or partial exercise of any right or remedy shall preclude any other or further exercise thereof or the exercise of any other right or remedy. No waiver by Company shall be effective unless it is in writing and such writing expressly states that it is intended to constitute such waiver. Any waiver given by Company of any right, power or remedy in any one instance shall be effective only in that specific instance and only for the purpose for which given, and will not be construed as a waiver of any right, power or remedy on any future occasion. The rights and remedies of Company herein provided are cumulative and not exclusive of any rights or remedies provided by Applicable Law.

(b) Successors and Assigns. This Guarantee shall be binding upon the successors of Guarantors and shall inure to the benefit of Company and its successors and permitted assigns. Guarantors shall not assign or transfer all or any part of its rights or obligations hereunder without the prior written consent of Company. Any purported assignment or delegation without such written consent shall be null and void. Company may assign its rights and obligations hereunder to any assignee of its rights under the Agreement permitted in accordance with the Agreement.

(c) Amendment. This Guarantee may not be modified, amended, terminated or revoked, in whole or in part, except by an agreement in writing signed by Company and Guarantors.

(d) Termination, Limits and Release. This Guarantee is irrevocable, unconditional and continuing in nature and is made with respect to all Guaranteed Obligations now existing or hereafter arising and shall remain in full force and effect until the time when in accordance with the terms of the Agreement all of the Guaranteed Obligations are fully satisfied and discharged, and then, and only then, this Guarantee shall automatically be released and shall be of no further force and effect; otherwise, it shall remain in full force and effect. Other than as set forth in the previous sentence, no release of this Guarantee shall be valid unless executed by Company and delivered to Guarantors. Under no circumstances will Guarantors’ aggregate liability hereunder exceed the Cap.

(e) Law and Jurisdiction.

(i) THIS GUARANTEE IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEVADA, WITHOUT REGARD FOR ANY PRINCIPLES OF CONFLICTS OF LAW THAT WOULD DIRECT OR PERMIT THE APPLICATION OF THE LAW OF ANY OTHER JURISDICTION.

(ii) GUARANTORS AND COMPANY IRREVOCABLY AGREE THAT THE STATE AND FEDERAL COURTS LOCATED IN CLARK COUNTY, NEVADA, SHALL HAVE EXCLUSIVE JURISDICTION TO HEAR AND DETERMINE ANY SUIT, ACTION OR
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PROCEEDING, AND TO SETTLE ANY DISPUTE, WHICH MAY ARISE OUT OF OR IN CONNECTION WITH THIS GUARANTEE, AND FOR SUCH PURPOSES HEREBY IRREVOCABLY SUBMIT TO THE JURISDICTION OF SUCH COURTS, AND GUARANTORS CONSENT TO THE JURISDICTION OF, AND TO THE LAYING OF VENUE IN, SUCH COURTS FOR SUCH PURPOSES AND HEREBY WAIVES ANY DEFENSE BASED ON LACK OF VENUE OR PERSONAL JURISDICTION OR OF INCONVENIENT FORUM.

(f) **Severability.** Any provision of this Guarantee that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. Where provisions of law or regulation resulting in such prohibition or unenforceability may be waived they are hereby waived by Guarantors and Company to the full extent permitted by law so that this Guarantee shall be deemed a valid binding agreement in each case enforceable in accordance with its terms.

(g) **Third Party Rights.** The terms and provisions of this Guarantee are intended solely for the benefit of Company and Guarantors and their respective successors and permitted assigns, and it is not the intention of Company or Guarantors to confer upon any other persons any rights by reason of this Guarantee.

(h) **No Set-off, Deduction or Withholding.** Guarantors hereby guarantee that payments hereunder shall be made without set-off or counterclaim and free and clear of and without deduction or withholding for any taxes; provided, that if the Guarantor shall be required under Applicable Law to deduct or withhold any taxes from such payments, then (i) the sum payable by Guarantor shall be increased as necessary so that after making all required deductions and withholdings (including deductions and withholdings applicable to additional sums payable pursuant to this sentence) the Company receives an amount equal to the sum it would have received had no such deduction or withholding been required, (ii) Guarantor shall make such deduction or withholding, and (iii) Guarantor shall timely pay the full amount deducted or withheld to the relevant governmental authority in accordance with Applicable Law.

(i) **Waiver of Right to Trial by Jury.** TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF GUARANTORS AND COMPANY WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS GUARANTEE. EACH OF GUARANTORS AND COMPANY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

(j) **Counterparts; Facsimile Signatures.** This Guarantee may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Signatures delivered by facsimile shall be deemed to be original signatures.

[Signature page follows.]
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IN WITNESS WHEREOF, each Guarantor has duly executed this Guarantee on the day and year first before written.

**Quinbrook Low Carbon Power LP**

By: Quinbrook Infrastructure Partners (Jersey) Limited
As Manager of Quinbrook Low Carbon Power LP
Name:
Title:

**Quinbrook Low Carbon Parallel Fund (US) LP**

By: Quinbrook Infrastructure Partners (Jersey) Limited
As Manager of Quinbrook Low Carbon Parallel Fund (US) LP
Name:
Title:

Acknowledged and Accepted:

**NEVADA POWER COMPANY D/B/A NV ENERGY, A NEVADA CORPORATION**

Name:
Title:
EXHIBIT 21

WORK SITE AGREEMENT

[See Attached.]
1. INITIAL PROVISIONS

1.1. This Work Site Agreement ("Agreement") is entered into by [General Contractor's Name] ("Primary Employer"), and IBEW Local Unions 357 & 396 ("the Unions").

1.2. The Gemini Solar Project, Solar Power XL, (the "Project") has a potential to provide approximately 690 MW as a solar photovoltaic power plant located in Southern Nevada. This location is known as the "Project Site". The Project is owned and operated by Arevia Power Company on behalf of Valley of Fire Solar, LLC ("Owner"). It is understood and agreed by and between the Parties to this Agreement that the final plans for the Project may be subject to modifications and approval by those public agencies possessing lawful approval authority over the Project and that this Agreement applies to the Project as it is finally approved by such entities and agencies. Once a final physical address is secured for this Project Site, they will be incorporated into this Agreement.

1.3. Owner is responsible for the construction of the Project and has engaged the Primary Employer to handle such construction.

1.4. As provided below, all persons or entities assigning, awarding or subcontracting Covered Work (as defined in Article 2) on the Project, or authorizing another party to assign, award or subcontract Covered Work on the Project, or performing Covered Work on the Project (all of whom are individually and collectively referred to as "Employer" or "Employers") will (except for the Owner and Primary Employer) become subject to this Agreement by executing Attachment A (the "Agreement To Be Bound").

1.5. The Unions are labor organizations whose members are construction industry employees who generally work in close proximity to one another at construction job sites and whose jobs are closely related and coordinated. The Unions are party to a multi-employer collective bargaining agreement ("Master Agreement") that covers the geographic area of the Project. Where the term Master Agreement is used, it means the existing Master Agreement in effect on the date hereof for the labor unions noted herein.

1.6. A large labor pool represented by the Unions will be required to execute the work involved in the Project. AREVIA and Employers wish, and it is the purpose of this Agreement to ensure, that a sufficient supply of skilled craft workers are available at the Project, that all construction work and related work performed by the members of the Unions on this Project proceed continuously and economically, without interruption, in a safe and efficient manner. The parties also expressly recognize that the Project is located in a desert region that is subject to high temperatures. Employers will provide a safe work site and comply with all
state and federal requirements related to protection from heat. The Unions will not seek to restrict productivity based on the desert location. In furtherance of these purposes and to secure optimum productivity, harmonious relations between the parties and the orderly performance of the work, the parties to this Agreement agree to establish adequate and fair wage levels and working conditions.

1.7. A central purpose of the parties in executing this Agreement is to guarantee labor peace on the Project by minimizing the jobsite friction that could arise at a common-situs jobsite when union employees are required to work alongside non-union employees in those other crafts with which they generally work in close proximity performing work that is closely related and coordinated, and by ensuring there will be no disruption of the work should any non-union workers be present to perform work outside the scope of the Agreement. This Agreement accomplishes these objectives by requiring that all Covered Work on the Project be performed by workers who are members of the Unions.

1.8. In the interest of the future of the construction industry in the local area, of which the Unions are a vital part, and to maintain the most efficient and competitive posture possible, the Unions pledge to work and cooperate with the Owner, Primary Employer and all other Employers to produce the most efficient utilization of labor and equipment in accordance with this Agreement. In particular, the Unions shall make all efforts to first source labor local to the Project Site. In addition, the Union shall not afford preferential status to other jobs in the jurisdiction; to the extent such preference will inhibit the availability of qualified workers for the Project.

2. SCOPE OF AGREEMENT

2.0. All work to construct Project covered by this Agreement as defined below is referred to as “Covered Work.” This Agreement also covers work done in temporary yards or facilities adjacent to or near the Project that is otherwise Covered Work described below. The scope of Covered Work set forth in this Agreement for this Project shall not be considered precedential.

2.1. IBEW Inside Covered Work Includes:

2.1.1. This Agreement covers the following on-site electrical construction work within the scope of the Union’s Master Agreement: handling and installation of photovoltaic panels, installation and connection of any electrical wires and cables, connections to power conversion stations, electrical fixtures, electrical appliances, electrical apparatus, electrical raceways or trays, electrical conduits, electrical instrumentation and controls. All of the foregoing work with the exception of any excluded work in Section 2.3 is referred to as “Covered Work.”

2.1.2. IBEW Inside Covered Work also includes all work performed by electrical craft labor that is part of startup and commissioning, including, but not limited to, loop checks and rework and modifications during start-up and commissioning. The Primary Employer, manufacturer's representatives, vendor's representatives, and plant operating personnel may supervise and direct employees performing startup and commissioning, including loop checks and rework and modifications during start-up and commissioning. This related craft work is
typically performed as part of a joint effort with these representatives and personnel. After a system or subsystem becomes operational and upon acceptance by the Primary Employer, Covered Work on that system or subsystem is completed. However, rework and modifications normally provided as a function of the initial construction effort, and other related initial construction work normally performed by members of the Unions, will be performed by members of the Unions. Nothing set forth in this Section 2.1.2 or the rest of this Agreement shall be construed as prohibiting or limiting the following: (1) permanent operating personnel, who are not members of the Unions, from operating systems prior to Covered Work being completed; or (2) the performance of industry standard work performed by a manufacturer or vendor or its representatives to satisfy its guarantee or warranty prior to startup of a piece of equipment.

2.2. IBEW Outside Line Covered Work includes all construction of transmission and distribution lines, outside substations, switchyards, and substation or switchyard related ground grids. To the extent there is additional work needed by Employer on the Project that is outside of the above language, but covered within the scope of work for the IBEW Outside Line Construction Agreement, IBEW Local 396 and the Employer agree to meet and confer to determine if that work can be covered by IBEW Local 396.

2.3. Excluded Employees from Covered Work: The following individuals/employees are specifically excluded from this Agreement and not subject to the provisions of this Agreement:

a) Supervisors or managers, assistant supervisors, superintendents technical or non-manual employees including, but not limited to executives, office and clerical personnel, clerks, project managers, drafters, engineers, surveyors, schedulers, planners, timekeepers, messengers/mail carriers, procurement and/or material receipt personnel, inspectors and testers (including necessary resources required for commissioning and testing scope of work), quality control/assurance personnel, janitors, guards, technicians, professionals, or any other employees above the classification of general foreman who perform administrative/clerical functions.

b) Employees and entities not engaged in the work listed in Section 2.1, 2.1.2 and 2.2, above;

c) Employees of any Employer or construction manager, except those performing Covered Work;

d) Vendors and employees of vendors engaged expressly for repair, testing, inspection, delivery, training, warranty work, or engaged in corrections of defective equipment or material;

e) Employees engaged in geophysical and/or environmental testing or other site-specific investigatory work (whether land, water or air);
f) Employees performing preconstruction site preparation work including
fence installation, cleaning, grubbing, grading and compaction and dust
control/watering;

g) Employees engaged in ancillary work on the Project which is performed
by third parties, such as electric utilities (i.e. NV Energy), gas utilities,
telephone companies and railroads, or any other similar work;

h) Employees engaged in the delivery and unloading of material, supplies
and equipment to the Project Site or to locations designated throughout
the Project Site for equipment and material staging, as determined by
the Owner or Employer;

i) Employees of any federal, state, county, city or other governmental
bodies and/or agencies or their contractors; and

j) Employees and contractors of lenders engaged in work on the Project
Site as part of the lenders' due diligence or monitoring, which work is
ancillary to Project work.

2.4. Purchase of any manufactured item produced in a genuine
manufacturing facility for the supply of products is not Covered Work and shall not
be considered subcontracting under Article 3 below. Any offsite fabrication, kitting,
preparation or other assembly of components for the Project is Covered Work and
shall be performed on site. For the convenience of the Employer, such work may be
performed offsite if performed in accordance with the union standards for the
applicable Union established by this Agreement. Covered Work does not include
creating inverter skids, if they are created, built, or assembled in a genuine
manufacturing facility.

2.5. The initial delivery of materials to the Project site, to a drop off location
within the site, or to a temporary yard at/or area near the Project is not Covered
Work. The loading, unloading and distributing of electrical materials within the site
after the initial delivery are Covered Work.

2.6. The manual and physical work typically performed by the Unions as
part of startup and commissioning prior to turnover acceptance pursuant to Section
2.7 is Covered Work. It is understood that the Owner, Primary Employer, or any
other Employers (including temporary employees under their direction performing
non-manual functions), manufacturer's representatives, vendor's representatives,
and plant operating personnel may supervise and direct start-up and commissioning
activities. If craft labor is required to perform commissioning and testing related
work, it will be performed as part of a joint effort with the commissioning and testing
representative directing the work and represented personnel.

2.7. Upon turnover and acceptance of a portion of the Project by the Owner
or Primary Employer, such portion of the Project shall no longer be subject to the
terms of this Agreement and any work done on such portion shall not be Covered
Work. In the event that the Owner or Primary Employer is not willing to accept the
Project until substantial completion of the entire Project is reached, after approval
by the Owner, the Primary Employer will issue to the Unions notice in writing of the
completion of the section of the Project and the issuance of this letter to the Union will constitute the end of the terms and conditions of this Agreement and any work done on such portion after the issuance of this letter shall not be Covered Work. A copy of this letter will be provided to Owner by the Primary Employer at the time of issuance to the Unions. The turnover process provided in this Section shall not diminish the scope of Covered Work that has customarily been included as part of Covered Work in similar projects.

2.8. Covered Work does not include operations or maintenance work.

3. SUBCONTRACTING

3.1. Primary Employer and each other Employer agree that they will contract for the assignment, awarding or subcontracting of Covered Work, or authorize another party to assign, award or subcontract Covered Work, only to a person, firm, corporation or other entity that, at the time the contract is executed, has become a party to this Agreement by executing the Agreement to Be Bound.

3.2. Primary Employer and each other Employer agree that they will subcontract Covered Work only to a person, firm, or corporation who is or becomes signatory to this Work Site Agreement and who is or becomes signatory to the Union's Master Agreement for any non-residential solar work. The subcontractor agrees to become a signatory of the Master Agreement under this provision only for the life of the current Master Agreement. Any Employer performing Covered Work on the Project shall, as a condition to working on the Project, become signatory to and perform all work under the terms of this Agreement and the Master Agreement. Before being authorized to perform any Covered Work, Employers (other than Primary Employer) shall become a party to this Agreement by signing an Agreement To Be Bound, which is provided as Attachment A to this Agreement. Every Employer shall notify the Unions in writing within five business days after it has subcontracted work, and shall at the same time provide to the Unions a copy of an Agreement To Be Bound executed by the Employer.

3.3. Nothing in this Agreement shall in any manner whatsoever limit the rights of Primary Employer or any other Employer, to subcontract work or to select its contractors or subcontractors, provided, however, that all Employers, at all tiers, performing Covered Work shall be required to comply with the provisions of this Agreement. Primary Employer and every other Employer shall notify each of its contractors and subcontractors of the provisions of this Agreement and require as a condition precedent to the award of any construction contract or subcontract for Covered Work or allowing any subcontracted Covered Work to be performed, that all such contractors and subcontractors at all tiers become signatory to this Agreement and the Master Agreement for non-residential solar work. If any Employer fails to provide the Union with the Agreement To Be Bound executed by its subcontractor, that Employer shall be liable for any contributions to any trust funds that the subcontractor, or any subcontractor to that subcontractor, fails to make
4. WAGES, BENEFITS, HOURS OF WORK, SHIFT WORK, HOLIDAYS

4.1. All employees covered by this Agreement (including foremen and general foremen if they are covered by a Master Agreement) shall be classified and paid wages, and contributions made on their behalf to multi-employer trust funds, all in accordance with the appropriate Master Agreement.

4.2. The standard work day shall consist of eight (8) hours of work between 6:00 a.m. and 5:30 p.m. with one-half hour designated as an unpaid period for lunch. Breaks will be allowed in accordance with Federal/State Law. The standard work week shall be five (5) consecutive days starting on Monday. Nothing herein shall be construed as guaranteeing any employee eight (8) hours of work per day or forty (40) hours of work per week.

4.3. It is recognized by the parties to this Agreement that the standard work week may not be desirable or cost effective for the Project, and other arrangements for hours of work may be considered. Such proposed modifications to the standard work week will be established with the consent of the Employer and the Union.

4.4. Shifts may be established when considered necessary by the Employer. Shift hours will be as follows: First shift will be eight (8) hours pay for eight (8) hours worked, plus one-half hour unpaid lunch period. Second shift will be eight (8) hours pay for eight (8) hours worked, plus the shift differential set forth in the Master Agreement.

4.5. A four (4) day, ten (10) hour per day work week may be established. Forty (40) hours per week constitutes the work week Monday through Thursday. Hours beyond ten (10) will be paid at the double time rate. Overtime on Friday will be paid at time and one-half for the first eight (8) hours; hours beyond eight (8) will be paid at the rate established in the Master Agreement, not to exceed double time. There shall be no make-up days.

4.6. The Employer may establish two four (4) day ten (10) hour per day shifts at the straight time rate of pay Monday through Thursday. The first shift shall be ten (10) hours pay for ten (10) hours worked at the regular straight time hourly rate, exclusive of thirty (30) minute unpaid meal period. The second shift shall be ten (10) hours pay for ten (10) hours worked plus the shift differential set forth in the Master Agreement.

4.7. There will be no pyramiding of overtime rates.

4.8. Recognized holidays shall be as follows: New Year's Day, Martin Luther King, Jr. Day, Presidents' Day, Memorial Day, Fourth of July, Labor Day, Veterans Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day. Under no circumstances shall any work be performed on Labor Day except in cases of emergency involving life or property. In the event a holiday falls on Saturday, the previous day, Friday, shall be observed as such holiday. In the event a holiday falls on Sunday, the following day, Monday, shall be observed as such holiday. There shall be no paid holidays. If employees are required to work on a holiday, they shall receive the appropriate rate as provided in the Master Agreement not to exceed double the straight time rate of pay. Work on Labor Day requires the prior approval.
of the Business Manager of the applicable Union. The listed holidays may be modified by mutual agreement of the Primary Employer and the Unions.

4.9. Employees performing Covered Work dispatched off the Helper Book shall, at a minimum, receive wages and benefits as specified in Attachment C.

5. UNION RECOGNITION AND REFERRAL

5.1. The Employers recognize the Unions signatory to this Agreement as the sole and exclusive collective bargaining agents for its construction craft employees performing Covered Work for the Project, and further recognize the traditional and customary craft jurisdiction of the Unions.

5.2. All employees performing Covered Work shall be or shall become and then remain members in good standing of the Union as a condition of employment on or before the eighth (8th) day of employment, or the eighth (8th) day following the execution of this Agreement, whichever is later.

5.3. The Unions shall be the source of all craft employees for Covered Work for the Project. Employers agree to be bound by the hiring and layoff practices of the Unions, including hiring of apprentices, and to utilize its registration facilities and referral systems. Notwithstanding this provision, Primary Employer and all other Employers shall have the right to determine the competency of all referrals; determine the number of employees required; determine the selection of employees to be laid-off and reject any applicant referred by the Unions.

5.4. The Unions will exert their utmost efforts to recruit sufficient numbers of skilled and qualified craft employees to fulfill the requirements of each Employer. The Unions and the Employers agree that they will not discriminate against any employee or applicant for employment because of race, color, religion, sex, sexual orientation, national origin, disability, age, pregnancy, any genetic information or any other protected classification protected by law or regulation. Primary Employer and each other Employer, and the Unions agree that they will not require any employee or applicant to submit to genetic testing or non-job related medical inquiries.

5.5. Primary Employer is aware of the importance of local hiring on any construction project. Local hiring brings a sense of community to the initiative and supports the local economy in which it is doing business. In continuance of that initiative, the parties agree that hiring will be from the Union's book for the geographic area.

5.6. In the event the referral facilities maintained by the Unions do not refer the employees as requested by the Employer within a forty eight (48) hour period after such requisition is made by the Employer (Saturdays, Sundays and Holidays excepted), the Employer may employ applicants from any source.

5.7. Employers may utilize the workmen dispatched from the Helper Books described in Attachment C. These workmen may be used for all work involving PV module installation and material/trash distribution/removal. Module Installation Crews shall be setup in teams of 1 Foreman, 3 Apprentices, and 3 Helpers.
Material Distribution Crews and Trash Crews shall have at least 1 (JW) foreman and any combination of Apprentices, Helpers, and Material Expediters not exceeding a crew size of 15 workmen. Once the modules are installed, any further work downstream of this identified work will be performed by either Apprentices or Journeymen as per the Master Agreement. In accordance with Section 4.28 of the Master Agreement, a foreman is required on any job with (3) or more workmen and may supervise up to (15) workmen including himself/herself.

5.8. If there are insufficient apprentices available, Primary Employer may utilize the workmen dispatched from the Helper Books with the consent of the Union.

6. STRIKES AND LOCKOUTS

6.1. During the term of this Agreement, the Unions agree that they shall not (and that they shall not cause their agents, representatives and employees) to incite, encourage, condone or participate in any strike, walkout, slowdown, sit-down, stay-in, boycott, sympathy strike, picketing or other work stoppage for any cause whatsoever with respect to this Project; and it is expressly agreed that any such action is in violation of this Agreement. In the event of a violation of this provision, any Employer shall be entitled to seek relief in court, specifically including injunctive relief, to restrain any such action on the part of the Unions, and/or any of their agents, representatives or employees, in addition to the Liquidated Damages for violation of this Section 6.1 of this Agreement.

6.2. Upon written notice of a violation to the Union and its' officers, and their agents, representatives, employees and persons acting in concert with it, the Union shall take immediate action and will use its best efforts to prevent, end or avert any such activity or the threat thereof by any of its officers, members, representatives or employees, either individually or collectively, including but not limited to, publicly disavowing any such action and ordering all such officers, representatives, employees or members who participate in such unauthorized activity to cease and desist from same immediately and to return to work and comply with its orders. Nothing in this Agreement shall be construed to limit or restrict the right of any of the parties to this Agreement to pursue fully any and all remedies available under law in the event of a violation of this Article 6.

6.3. The parties agree that to the extent the Master Agreement provisions of the Union's current labor agreement apply to this Project, they shall continue to apply throughout the duration of this Project notwithstanding the expiration of that agreement for all affected Employers on this Project.

6.4. Neither Owner, Primary Employer, nor any other Employer shall incite, encourage or participate in any lockout or cause to be locked out any employee covered under the provisions of this Agreement. The term “lockout” does not refer to the discharge, termination or layoff of employees by any Employer for any reasons in the exercise of its rights as set forth in any provision of this Agreement, nor does “lockout” include a decision by Owner, Primary Employer, or any Employer to terminate or suspend work on the Project Site or any portion thereof for any reason other than a labor dispute.
6.5. Notwithstanding the provisions of Section 6.1, it is agreed that the Union retains the right to withhold the services of its members from a particular Employer who fails to make timely payments to the Union’s benefit plans, or fails to timely pay its weekly payroll, in accordance with the Master Agreement; provided, in the event the Union or any of its members withholds their services from such Employer, Owner, Primary Employer, or the applicable Employer shall have the right to replace such Employer with any other Employer who executes the Agreement To Be Bound. The Union shall not withhold the services of its members under this provision without first giving Owner, Primary Employer, and the individual Employer alleged to be delinquent in its payments at least five (5) business days’ notice, in the case of payroll delinquencies, and ten (10) business days’ notice, in the case of benefit fund delinquencies, and an opportunity to cure the delinquency by tendering payment to the relevant employees or trust funds.

7. GRIEVANCE PROCEDURE

7.1. It is mutually agreed that any question arising out of and during the term of this Agreement involving interpretation and application of this Agreement shall be considered a grievance. Any grievances involving interpretation and application of this Agreement will be governed by this Agreement’s grievance procedure as set forth below. Any grievances involving interpretation and application of the Master Agreement will be governed by the Master Agreement’s grievance procedure.

7.2. Owner, Primary Employer, and any other Employer, as well as the Union, may bring forth grievances under this Article.

7.3. A grievance shall be considered null and void if not brought to the attention of the Employer(s) within five (5) working days after the incident that initiated the alleged grievance occurred or was discovered, whichever is later. The term “working days” as used in this Article shall exclude Saturdays, Sundays or holidays regardless of whether any work is actually performed on such days.

7.4. Grievances shall be settled according to the following procedure, except that grievances that do not involve an individual grievant shall be discussed by Primary Employer and the Union, and then, if not resolved within five (5) working days of written notice unless extended by mutual consent, commence at Step 4:

7.5. Step 1. The steward and the grievant shall attempt to resolve the grievance with the Employer’s supervisor within five (5) working days after the grievance has been brought to the attention of the Employer.

7.6. Step 2. In the event the matter remains unresolved in Step 1 above after five (5) working days, within five (5) working days after notice to the Union, the alleged grievance, in writing, may then be referred to the Business Manager of the Union and the Labor Relations representative of the Employer for discussion and resolution. A copy of the written grievance shall also be mailed/e-mailed to Primary Employer.

7.7. Step 3. In the event the matter remains unresolved in Step 2 above after five (5) working days, within five (5) working days, the alleged grievance, in
writing, may then be referred to the Business Manager of the Union and the
Manager of Labor Relations of the Primary Employer or the Manager's designated
representative and the Owner for discussion and resolution.

7.8. Step 4. If the grievance is not settled in Step 3 within five (5) working
days, within five (5) days thereafter, either party may request the dispute be
submitted to arbitration or the time may be extended by mutual consent of both
parties. The request for arbitration and/or the request for an extension of time
must be in writing with a copy to Primary Employer and the Owner. Should the
parties be unable to mutually agree on the selection of an arbitrator, selection for
that given arbitration shall be made by seeking a list of seven (7) labor arbitrators
with construction experience from the Federal Mediation and Conciliation Service
and alternately striking names from the list of names on the list until the parties
agree on an Arbitrator or until one name remains. The first party to strike a name
from the list shall alternate between the party bringing forth the grievance and the
party defending the grievance. Primary Employer shall keep a record of the
sequence and shall notify the parties to the grievance as to which party has the
right to strike a name first.

7.9. The selected arbitrator ("Arbitrator") shall conduct a hearing at which
the parties to the grievance shall be entitled to present testimonial and
documentary evidence. Hearings will be transcribed by a certified court reporter.
The parties shall be entitled to file written briefs after the close of the hearing and
receipt of the transcript.

7.10. Upon expiration of the time for the parties to file briefs, the Arbitrator
shall issue a written decision that will be served on all parties and on Primary
Employer. The Arbitrator shall have the authority to utilize any equitable or legal
remedy to prevent and/or cure any breach or threatened breach of this Agreement.
The Arbitrator's decision shall be final and binding as to all parties signatory to this
Agreement. No arbitration decision or award under this Article may provide
retroactive relief of any kind exceeding fifteen (15) calendar days prior to the date
the grievance was first initiated at Step 1.

7.11. The cost of the Arbitrator and the court reporter, and any cost to pay for
facilities for the hearing, shall be borne equally by the parties to the grievance. All
other costs and expenses in connection with the grievance hearing shall be borne by
the party who incurs them.

7.12. The Arbitrator's decision shall be confined to the issue(s) posed by the
grievance and the Arbitrator shall not have the authority to modify, amend, alter,
add to or subtract from any provision of this Agreement.

7.13. Any party to a grievance may invite Owner or Primary Employer to
participate in resolution of a grievance. Owner or Primary Employer may, at its
own initiative, participate in Steps 1 through 3 of the grievance procedure.

7.14. In determining whether the time limits of Steps 2 through 4 of the
grievance procedure have been met, a written referral or request shall be considered
timely if it is personally delivered, sent by overnight mail or e-mailed within the
five (5) working day period. Any of the time periods set forth in this Article may be
extended in writing by mutual consent of the parties to the grievance, and any written referral or request shall be considered timely if it is personally delivered, sent by overnight mail or e-mailed during the extended time period.

7.15. For purposes of e-mailed copies of grievances to Owner or Primary Employer, they can be sent to the following e-mail address: ------------------------------------------@----------------------

8. MANAGEMENT RIGHTS

8.1. Except as expressly limited by the specific provisions of this Agreement, the Owner, Primary Employer, and all other Employers retain full and exclusive authority for the management of their respective Project operations and work forces, except as expressly limited by the terms of this Agreement. This authority includes, but is not limited to, the right to plan, direct and control the operations of all the work and the work force; decide the number to be hired and the qualifications therefore; decide the number and type of employees assigned to any specific work; hire, promote, transfer, and layoff employees; select and hire directly all supervisory personnel above the classification of general foreman it considers necessary and desirable, without such persons being referred by the Union; discipline or discharge of employees; decide the type of equipment to be used; decide the assignment and schedule of work; the promulgation of reasonable Project work rules, safety rules, and drug and alcohol policies pursuant to Section 10.8; determine the work methods and procedures; determine the competency of all employees; assign and schedule work and determine when overtime will be worked; determine the selection and use any type or kind of materials, apparatus or equipment regardless of source, manufacturer or designer; and determine the requirement, timing and number of employees to be utilized for Covered Work. Except as provided in the Master Agreement, no rules, customs, or practices of the Unions which limit or restrict productivity or efficiency of the individual, and/or joint working efforts with other employees shall be permitted or observed. The foregoing enumeration of management rights shall not be deemed to exclude other functions not specifically covered by this Agreement. The Owner, Primary Employer, and all other Employers, therefore, retain all legal rights not specifically given up in this Agreement.

8.2. There shall be no limitations or restriction upon the Owner, Primary Employer, or any other Employer's choice of materials, techniques, methods, technology or design, or, regardless of source (including but not limited to country source of origin) or location, upon the use and installation of equipment, machinery, package units, pre-cast, pre-fabricated, pre-finished, or pre-assembled materials of any kind, tools, or other labor-saving devices. The Union agrees that such material and equipment is to be installed without incident.

8.3. In recognition of the dynamic nature of the PV solar industry, the parties agree that Owner, Primary Employer or any other Employer may apply new technologies to the Project as they are developed, (including technological advances in the construction of PV solar plants) even if such application results in a reduction of the amount of labor on the Project.
8.4. All construction equipment assigned by an Employer to the Project shall be under the control of Owner, Primary Employer or any other Employer and they shall have the right to determine how many pieces of construction equipment an individual shall operate.

8.5. Owner, Primary Employer or any other Employer retains the right to deny access to the Project to any employee on the basis of violating any safety processes and procedures.

9. SUCCESSORSHIP AND SURVIVABILITY

9.1. The subcontracting obligations described in Article 3 are independent obligations of Primary Employer which shall survive any full or partial termination of Primary Employer's involvement in the Project for any reason, including, without limitation: (i) any full or partial termination or transfer of Primary Employer's right to control and coordinate construction of Covered Work on the Project; (ii) any full or partial termination or transfer of a contract, if any, between Primary Employer and the Owner for any Covered Work; (iii) the transfer of all or any portion of the Project or any interest in the Project by the Owner; or (iv) any other event that results in the replacement of Primary Employer with another contractor.

9.2. The parties agree that: (i) if Primary Employer's involvement in the Project is terminated and (ii) Covered Work is performed by a contractor or subcontractor that is not in compliance with the provisions of Article 3, then Primary Employer shall pay liquidated damages for each hour of Covered Work performed, as set forth on Attachment B.

9.3. Upon execution and delivery of an agreement assuming all the obligations of this Agreement and determination by the Unions that the successor is financially responsible, Primary Employer shall be released from any liability under this Agreement for the payment of liquidated damages under this Article 9 and shall have no liability for any breach of this Agreement by a successor employer or contractor. A successor shall be considered financially responsible if the Unions, in the exercise of their reasonable judgment, determine that the successor is financially capable of completing the Project and complying with the obligations and undertakings of Primary Employer under this Agreement, including any obligation to pay liquidated damages under this Article 9.

9.4. This Article shall be enforceable in any court of competent jurisdiction, and shall not be subject to the grievance procedure.

10. GENERAL PROVISIONS

10.1. If any article or provision of this Agreement shall be declared invalid, inoperative, or unenforceable by any competent authority of the executive legislative, judicial or administrative branch of the federal or state government, the Employers and the Union shall suspend the operation of such article or provisions during the period of its invalidity and shall substitute by mutual consent, in its place and stead, an article or provision which will satisfy the objections to its validity and which, to the greatest extent possible, will be in accord with the intent.
and purpose of the article or provision in question. At all relevant times, the provisions of Article 6 will apply.

10.2. If any article or provision of this Agreement shall be held invalid, inoperative or unenforceable by operation of law, or by any of the above mentioned tribunals of competent jurisdiction, the remainder of the Agreement or application of such article or provision to persons or circumstances other than to which it has been held invalid, inoperative or unenforceable shall not be affected thereby.

10.3. Except as enumerated in this Agreement, all other terms and conditions of employment described in the Master Agreements that are in effect shall apply.

10.4. The provisions of this Agreement shall take precedence over conflicting provisions of the Master Agreement of the Union.

10.5. The parties agree that all covered employees will be required to be at his or her work station and ready to begin work at the designated starting times. The parties support a pay arrangement that provides for the covered employee to be at his or her work station and ready to work at the start of this shift without compensation for the time traveled to his or her workstation however the parties further agree that employees will be compensated at the appropriate hourly rate of pay for travel time back to their vehicles from the workstation.

10.6. Each person executing this Agreement represents and warrants that he or she is authorized to execute this Agreement on behalf of the party or parties indicated.

10.7. Rights of Owner. Nothing in this Agreement shall be construed as limiting the Owner, in its sole discretion at any time to terminate, delay, cease, or suspend construction activities, in whole or part, on this Project and/or shut down the Project Site or any part thereof for reason other than a labor dispute without any liability whatsoever, except for liability incurred prior to such action.

10.8. This Agreement may be executed in counterparts.

10.9. The parties recognize that Primary Employer strongly supports a drug free work environment on each of its projects. To that end, the parties agree that Primary Employer's drug testing policies shall be applied to the Project by each Employer on the site. Specifically, that policy includes pre-employment drug testing prior to starting work on the site, random drug testing on the worksite once employed and drug testing following any industrial accident resulting in an injury or any damage to Owner, Primary Employer, or any other Employer's property. Should Primary Employer require a pre-employment drug test of the employee(s) of the signatory Employer as noted above, and the employee(s) (through the signatory Employer) will be paid (1) hour show up pay if he successfully passes the pre-employment drug test. Should an employee(s) initial test be deemed inconclusive and require further testing that employee(s) shall be paid (2) hour waiting time per day upon successfully passing the pre-employment drug testing. This pay provision shall only apply to pre-employment drug tests.
10.10. Any notices required under this Agreement shall be given as follows. Either party may notify the other in writing if its person designated to receive notice is changed.

To Primary Employer:

Al D. Davis, Business Manager –
Financial Secretary
IBEW Local 357
808 N. Lamb Blvd.
Las Vegas, NV 89110
Telephone: (702) 452-9357

With a copy to:

Jesse Newman, Business Manager –
Financial Secretary
IBEW Local 396
3520 Boulder HWY
Las Vegas, NV 89121
Telephone: (702) 457-3011

Mark Boyadjian
Arevia Power Company
1044 10th Avenue
Redwood City, CA 94063

To the Unions:

11. TERM OF AGREEMENT

11.1. The term of this Agreement shall commence on the date an agreement is executed between Primary Employer and Owner for the Project regarding this Project as identified in Section 1.2, and shall continue in effect until completion of all Covered Work pursuant to Article 2.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and effective as of 12/27, 2017.

[GENERAL CONTRACTOR]

By:
Its:

[Signature]

AREVIA POWER COMPANY

By: Mark Boyadjian
Its: Managing Partner, Arevia Power

IBEW LOCAL 396

By: Jesse Newman
Its: IBEW 396 Business Manager –
Financial Secretary

IBEW LOCAL 357

By: Al D. Davis
Its: IBEW 357 Business Manager –
Financial Secretary
ATTACHMENT A
AGREEMENT TO BE BOUND

WORK SITE AGREEMENT
GEMINI SOLAR PROJECT

The undersigned hereby certifies and agrees that:

1.) It is an Employer as that term is defined in Section 1.4 of the Gemini Solar Project Work Site Agreement ("Agreement") because it has been, or will be, awarded a contract or subcontract to assign, award or subcontract Covered Work on the Project (as defined in Article 2 of the Agreement), or to authorize another party to assign, award or subcontract Covered Work, or to perform Covered Work.

2.) In consideration of the award of such contract or subcontract, and in further consideration of the promises made in the Agreement and all attachments thereto (a copy of which was received and is hereby acknowledged), it accepts and agrees to be bound by the terms and conditions of the Agreement, together with any and all amendments and supplements now existing or which are later made thereto.

3.) If it performs Covered Work, it will be bound by the legally established trust agreements designated in local master collective bargaining agreements, and hereby authorize the parties to such local trust agreements to appoint trustees and successor trustee to administer the trust funds, and hereby ratifies and accepts the trustees so appointed as if made by the undersigned.

4.) It has no commitments or agreements that would preclude its full and complete compliance with the terms and conditions of the Agreement.

5.) It will secure a duly executed Agreement To Be Bound, in form identical to this document, from any Employer(s) at any tier or tiers with which it contracts to assign, award, or subcontract Covered Work, or to authorize another party to assign, award or subcontract Covered Work, or to perform Covered Work.

DATED: __________ Name of Employer ____________________________

__________________________________
(Authorized Officer & Title)

__________________________________
(Address)
ATTACHMENT B
SCHEDULE OF LIQUIDATED DAMAGES FOR BOTH PARTIES

WORK SITE AGREEMENT
GEMINI SOLAR PROJECT

1. Strikes: In the event the Union violates the terms of Section 6.1 of the Work Site Agreement, including without limitation, by interfering with the Project or by supporting a strike at the work site, then the Union shall be jointly and severally liable for an amount equal to twenty thousand dollars ($20,000) for each day in which the Union is in violation of the terms of Sections 6.1.

2. Failure of Successor to Assume. In the event Primary Employer fails to cause its successor to assume the Work Site Agreement, Primary Employer shall pay an amount equal to the journeyman electrician's or journeyman lineman's total compensation, as applicable, for each hour that Covered Work was performed on the Project within the scope of this Agreement by employees of contractors or subcontractors who are not signatory to this Agreement as follows:

   Fifty Percent (50%) per hour to the qualified pension plan and
   Fifty Percent (50%) per hour to the qualified health and welfare plan

of the Unions performed by the contractor(s) or subcontractor(s) not signatory to this Agreement. The parties agree that the Unions shall enforce, collect and receive the liquidated damages described herein on behalf of its qualified pension plan and its qualified health and welfare plan. The qualified pension plans and the qualified health and welfare plans shall have no right to independently enforce the provisions of this Agreement.

3. The liability of the Owner, Primary Employer, any other Employer and/or the Union under this Agreement shall be several and not joint. Neither the Owner, nor any Primary Employer or any other Employer shall be liable for any violations of this Agreement by any other contractor or party; and the Unions shall not be liable for any violations of this Agreement by any other union or party.

4. In no event shall Owner, Primary Employer's or Unions' liability for violation of this Agreement exceed $1,000,000 (One Million Dollars).
Appendix C

IBEW 357 Gemini Solar Project Helper Rates

<table>
<thead>
<tr>
<th>Date</th>
<th>Check</th>
<th>H&amp;W</th>
<th>DFW</th>
<th>B-Plan</th>
<th>JATC</th>
<th>LMCC</th>
<th>NLMCC</th>
<th>NEBF 3%</th>
<th>CAF 0.2%</th>
<th>Total</th>
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<tbody>
<tr>
<td>2/1/17</td>
<td>$21.00</td>
<td>$5.45</td>
<td>$.06</td>
<td>$1.00</td>
<td>$0.66</td>
<td>$0.15*</td>
<td>$0.01</td>
<td>$0.63</td>
<td>$0.04</td>
<td>$29.00</td>
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<td>1/1/19</td>
<td>$21.75</td>
<td>$5.45</td>
<td>$.06</td>
<td>$1.00</td>
<td>$0.66</td>
<td>$0.15*</td>
<td>$0.01</td>
<td>$0.65</td>
<td>$0.04</td>
<td>$29.77</td>
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<tr>
<td>1/1/20</td>
<td>TBD</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* LMCC is a total of $0.30 $0.15 contribution from the contractor and $0.15 deduction from the employees' wages.

Wages and Benefits are for workers dispatched from the Helper Books for the Gemini Solar Project.
Subject to limitations described in Exhibit 1, Sections 6 and 7.
EXHIBIT 23

APPROVED VENDORS LIST

[To be provided by Buyer]
EXHIBIT 24

STORAGE OPERATING PROCEDURES

The operating guidelines of the Generation Facility and Energy Storage Facility will be defined herein. The main operations are broken into two parts: Charging Notice and Discharging Notice. Final Operating Procedures for the Facilities will be mutually developed and agreed upon within 90 days of the Operation Date. The procedures will be periodically reviewed to optimize operations for both parties. Parties shall cooperate to integrate the systems and controls necessary to implement the Operating Procedures.

I. Forecasting

A. Supplier will provide to Buyer a 7-day hourly rolling availability forecast, the Availability Notice, of the solar resource, which incorporates the following information:
   1) Supplier’s optimal charging schedule, including charging window and hourly charging rate;
   2) hourly maximum charging rate availability of the Storage Facility;
   3) hourly minimum charging rate availability of the Storage Facility; and
   4) current status of the Storage Facility, expressed in a percentage of total battery available for discharge or state of charge;

B. Planned and forced outage notification and scheduling shall be via the Availability Notice. Additionally, in the event of a forced outage, Supplier shall notify the appropriate NV Energy personnel of forced outage and expected return to service.

II. Charging Notices and Discharging Notices

A. A Discharging Notice will be delivered to the Supplier in conjunction with each Charging Notice

B. Buyer will provide to Supplier, per the Western Electricity Coordinating Council (“WECC”) pre-scheduling calendar, a forecasted Charging Notice and Discharging Notice. The Charging and Discharging Notice will incorporate Supplier’s solar resource availability per Supplier’s 7-day hourly rolling forecast.

C. For the Charging component of the Charging and Discharging Notice, Buyer shall provide Supplier with the following information:
   1) the hours in which Supplier shall charge the Storage Facility;
   2) the Stored Energy Level the Supplier shall charge the Storage Facility to, by the end of the last hour in which Supplier shall charge the Storage Facility.
   3) Buyer, whenever feasible, will utilize Supplier’s provided optimal charging window identified in section I.A.1.

D. For the Discharging Notice, Buyer shall provide Supplier with the following information:
   1) the hours in which the Supplier shall discharge the Storage Facility;
   2) the energy discharged in each hour the Supplier shall discharge the Storage Facility.
EXHIBIT 24

STORAGE OPERATING PROCEDURES

III. Modifications to the Charging and Discharging Notices

A. On the day of operation, to the degree that it is technically feasible, Buyer reserves the right to make adjustments to its Charging Notices and Discharging Notices. To this end, Supplier will provide to Buyer real-time software application(s) which allow(s) Buyer to access the Stored Energy Level status of the Storage Facility, as well the current forecasts of PV generation.

B. To make intraday adjustments on the day of operation, Buyer will communicate with Supplier in a manner that is mutually agreeable to both Buyer and Supplier:
   1) either through a software application which allows Buyer to directly adjust the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility; or
   2) telephonically with Supplier to verbally request adjustments to the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility; or
   3) through a software application which allows for real-time communication, such as Microsoft Lync, Skype for Business, etc. to request adjustments to the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility.
   4) A real-time dispatch signal will be the primary control of the Facility

C. Supplier will communicate with Buyer, utilizing the manner of communication mutually agreed upon above, whether Buyer’s requested adjustment to the charge or discharge schedule contained in Buyer’s Charging Notice and Discharging Notice is feasible, both in terms of the hour(s) requested, as well as the rate of charge or discharge requested. Should Buyer’s requested adjustment to the charge or discharge schedule be infeasible, due to the current charged or discharged status of the Storage Facility, Buyer and Supplier shall mutually agree to:
   1) an alternate adjustment to the charge or discharge schedule, which is technically feasible given the Stored Energy Level or discharge of the Storage Facility; or
   2) reject Buyer’s adjustment to the charge or discharge schedule, and resume Buyer’s original charge or discharge schedule as specified in Buyer’s Charging and Discharging notice.
   3) any adjustments necessary to future charge or discharge schedules contained in Buyer’s Charging and Discharging Notices which will be rendered infeasible due to Buyer’s requested adjustment to the charge or discharge schedules on the day of operation.

IV. Delivery

A. The Supplier will deliver the Discharging Energy to the Delivery Points. To this end, Supplier will provide to Buyer a real-time software application which allows Buyer to access the status of the Storage Facility, as well the current forecasts of PV generation.
A real-time point of delivery in response to:
EXHIBIT 24

STORAGE OPERATING PROCEDURES

1. Primarily with a real-time dispatch command Per section III above
2. Or an automated, scheduled Discharge Notice per section II.D above as a backup.

The total discharged energy in real-time will be limited to the Stored Energy Level (less any losses to deliver such stored Energy to the Delivery Points) and to the available power rating of the Generating Facility.

V. Measurement and Verification

Buyer will also have real-time access to view the Supplier’s Energy Management system and data historian that will monitor the Storage Facility’s state of health metrics as well usage metrics such as Equivalent Cycles to date. In accordance to Exhibit 1 Buyer will be allowed to use 273 Equivalent Cycles per year. Buyer will be able to monitor the amount of cycles that have occurred over the life of the project on a real-time basis. As soon as the Storage Facility meets the cycle limit, the supplier will no longer be able to execute Charge and Discharges for that year.

VI. Scheduling Reports

Supplier will send out a daily report to the Buyer so they may transmit to other parties. The report will include at a minimum the following day’s Charging Notice and Discharging Notice as well as forecasted Energy Generation, including the forecasted output of the solar facility in so much as it is reduced by charging the Storage Facility.

VII. Operating Parameters

<table>
<thead>
<tr>
<th>#</th>
<th>OPERATING PARAMETER</th>
<th>VALUES</th>
<th>NOTES</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Charging Method</td>
<td>Constant Power (CP)-Constant Voltage (CV)</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Discharging Method</td>
<td>Constant Power (CP)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Maximum CP-rate for Charging and Discharging the Storage Facility</td>
<td>400 MWDC, which can be adjusted accordingly, as reasonably agreed upon by the Parties, based upon the final design of the Facility</td>
<td>Measured at the Storage Facility Metering Point</td>
</tr>
<tr>
<td>4</td>
<td>Charging Source</td>
<td>Generating Facility only</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Maximum Annual Average State of Charge (SOC)</td>
<td>35.0%</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Resting State of Charge (SOC) of the Storage Facility</td>
<td>20%-30% or as per manufacturer recommendation</td>
<td>When not actively charging or discharging for more than a period of 24 hours, the SOC of the</td>
</tr>
</tbody>
</table>

24-3
<table>
<thead>
<tr>
<th></th>
<th>Operational State of Charge (SOC) Limits</th>
<th>0%-100% or as per manufacturer recommendation</th>
<th>Storage Facility shall be maintained in this range</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Maximum Number of Equivalent Full Cycles per Calendar Year</td>
<td>365</td>
<td>Buyer allowed to use a total of 273 cycles in all months other than June, July and August</td>
</tr>
<tr>
<td>9</td>
<td>Maximum Cumulative Energy Discharge per Calendar Year</td>
<td>516,840 MWh</td>
<td>which is 380MW (the Storage Contract Capacity (MW) of the Storage Facility for the given Contract Year) * 3.726h * 365 = 516,840 MWh</td>
</tr>
<tr>
<td>10</td>
<td>Maximum Cumulative Energy Discharge per Calendar Day</td>
<td>1,416 MWh</td>
<td>which is 380MW (the Storage Contract Capacity (MW) of the Storage Facility for the given Contract Year) * 3.726h = 1,416 MWh</td>
</tr>
</tbody>
</table>
EXHIBIT 25

STORAGE CAPACITY TESTS

Upon no less than ten (10) Business Days prior notice to Buyer, and at any time and from time to time up until the Commercial Operation Date, Supplier shall schedule and complete a Storage Capacity Test to determine the Storage Contract Capacity of the Storage Facility for the first Contract Year. The Storage Capacity Test shall require the Supplier to maintain Discharging Energy from the Storage Facility for three and seven-tenths (3.7) consecutive hours and the Storage Contract Capacity in megawatts (MW) shall be determined as the quotient of the aggregate quantity of Discharging Energy (MWh) at the end of the three and seven-tenths (3.7) hour test period, as measured at the Delivery Points, divided by three and seven-tenths (3.7); provided, however, that the Storage Contract Capacity cannot exceed three hundred eighty (380) MW.

Thereafter, at least once per Contract Year within the first quarter of each Contract Year, upon no less than five (5) Business Days prior notice to Buyer, Supplier shall schedule and complete a Storage Capacity Test. In addition, Buyer shall have the right to require a retest of the Storage Capacity Test at any time upon five (5) days prior written notice to Supplier if Buyer reasonably believes that the Storage Capacity has varied materially from the results of the most recent tests. Supplier shall have the right to run up to four (4) retests of the Storage Capacity Test at any time upon five (5) days prior written notice to Buyer (or any shorter period reasonably acceptable to Buyer consistent with Good Utility Practice). Except for establishing the Storage Contract Capacity prior to the Commercial Operation Date, the Supplier may with Buyer’s approval, fulfill the requirement to conduct a Storage Capacity Test by use of operational data from a Meter.

No later than five (5) days following any Storage Capacity Test, Supplier shall submit a testing report detailing results and findings of the test. The report shall include Meter readings and plant log sheets verifying the operating conditions and output of the Storage Facility. The actual capacity determined pursuant to a Storage Capacity Test shall become the new Storage Contract Capacity at the beginning of the day following the completion of the test for all purposes under this Agreement.

Supplier will perform a Storage Capacity Test generally in the following manner and utilizing the following steps:

1) Supplier may conduct any pre-capacity test activities required or recommended by the Storage Facility equipment suppliers, including charging or discharging the Storage Facility, prior to commencing step 2 below;

2) Supplier will fully charge the Storage Facility so that it is in a state that it is made commonly and typically available to Buyer as fully charged and dispatchable;

3) Supplier will discharge the Storage Facility at full capacity, over a duration of three and seven-tenths (3.7) consecutive hours;

4) Supplier will add the quantity of MWh produced by the Storage Facility during the three and seven-tenths (3.7) consecutive hours to produce a sum quantity of MWh for the three and seven-tenths (3.7) hour full discharge of the Storage Facility.
5) Supplier will divide the sum quantity of MWh produced over the three and seven-tenths (3.7) hour full discharge of the Storage Facility by a factor of three and seven-tenths (3.7), to produce a value that will become the Storage Contract Capacity for the Contract Year.

Example:
Hour 1 Discharge = 25 MWh
Hour 2 Discharge = 25 MWh
Hour 3 Discharge = 25 MWh
Partial Hour 4 Discharge = 17.5 MWh
25 + 25 + 25 + 17.5 = 92.5 MWh
92.5 MWh/3.7 hours = 25 MWh
Storage Contract Capacity = 25 MW
EXHIBIT 26

STORAGE AVAILABILITY LIQUIDATED DAMAGES

Availability Liquidated Damages

The Availability Liquidated Damages in Dispatch Availability Month \( m \) in which the Monthly Storage Availability is less than the Guaranteed Storage Availability shall be calculated as follows:

\[
\text{Availability Liquidated Damages}_m = \text{Undischarged Energy Price}_m \times \text{Excess Undischarged Energy}_m
\]

Where:

\[
\text{Availability Liquidated Damages}_m = \text{Availability Liquidated Damages in Dispatch Availability Month (m) (in $)}
\]

\[
\text{Availability Liquidated Damages Monthly Cap (each Dispatch Availability Month)} = $1,000,000
\]

\[
\text{Undischarged Energy Price}_m = \text{simple average of the Market Price for the hours that the Storage Facility was unavailable in Dispatch Availability Month (m) (in $/MWh)}
\]

\[
\text{Undischarged Energy}_m = \text{The total amount of Discharging Energy in Dispatch Availability Month (m), excluding Excused Products, that Buyer could have scheduled and received at the Delivery Points pursuant to Section 14.3 from the Storage Facility but was unable to schedule and receive because the Storage Facility was, in whole or in part, mechanically out of service or otherwise not performing in accordance with the operational requirements specified in Exhibits 1 and 24, such amount of Discharging Energy to be reasonably determined by Supplier (i) during the period the Storage Facility was out of service, in whole or in part, or otherwise not performing in accordance with the operational requirements specified in Exhibits 1 and 24, and (ii) consistent with the Operating Procedures and operational requirements specified in Exhibits 1 and 24 (in MWh). During the months of January, February, March, April, October, November and December, an outage that is not a Planned Outage per Section 11, but for which Seller provided notice to Buyer prior to or included in the Availability Notice, shall not be considered as contributing to this calculation of Undischarged Energy}_m \text{ provided the total hours of such Storage Facility unplanned}
\]

26-1
outages when combined with those of Planned Outages in the same Contract Year (based on the potential Discharging Energy or Dispatch Availability Amounts, as applicable, for such Delivery Hours) shall not exceed four percent (4%) of the total annual Dispatch Availability Amounts for all hours in the applicable Contract Year (prorated for the Stub Period, if any) unless otherwise approved by Buyer.

\[
\text{Excess Undischarged Energy}_m = \text{Undischarged Energy}_m - 2\% \text{ of the Storage Capacity at Point of Delivery}_m.
\]

\[
\text{Storage Capacity at Point of Delivery}_m = \text{the product of (a) Storage Contract Capacity for Dispatch Availability Month}_m, \text{ multiplied by (b) three and seven-tenths (3.7) hours, multiplied by (c) the number of days in Dispatch Availability Month}_m.
\]

\[
\text{Monthly Storage Availability} = \frac{\text{(Storage Capacity at Point of Delivery}_m \right) - \text{(Undischarged Energy}_m)}{\text{(Storage Capacity at Point of Delivery}_m)}
\]
EXHIBIT 27

BACKCASTING TOOL GENERAL INPUTS

The main concepts of backcasting are broken into two parts: Resource-Adjusted Backcast Amount and Availability Backcast Amount. Both concepts are aimed at determining what the Generating Facility’s solar generation capability, adjusted for various factors, would have been in cases where the actual solar output was dispatched lower than the Generating Facility’s full capacity. Both are intended to calculate the energy that could have been generated by the Generating Facility and delivered to the Delivery Points, absent the use of the Storage Facility, except as relating to Buyer’s rights in Section 14.3.2, in which case the Availability Backcast Amount should also include the energy that could have been used as Full Requirements Period Charging Energy (including otherwise clipped energy) and energy the Facility was available to deliver but could not deliver to the extent of any unavailability of the Facility resulting from one or more of the events described in this Section 3.6.6.

Final methodologies for backcasting shall be mutually developed and agreed upon no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6 based on industry-standard methodologies. The methodologies will be periodically reviewed to optimize operations, administrative efficiency and accuracy for the benefit of both parties. The Backcasting Tool will be calibrated one year after the Commercial Operation Date, and periodically thereafter, with actual measurements taken from the Generation Facility. Parties shall cooperate to integrate the systems and controls necessary to implement backcasting.

Backcasting will, in general, consist of a set of calculations and a mix of inputs to those calculations that include, but are not limited to, technical assumptions, real-time instrument measurements, historic instrument measurements, and data reported by Supplier. The inputs may include but are not limited to:

- As built designs;
- Generation Facility planned degradation as identified in Exhibit 1;
- Measured onsite plane of array (POA) irradiance;
- Measured module temperature;
- Measured onsite soiling conditions;
- All applicable losses to the Delivery Points including transformation and transmission losses from the PV array to points of delivery;
- Site controller and any ACG set-point limitations at the Delivery Points;
- Measurement uncertainties of equipment;
- Downtime/Planned Outages;
- Forced and maintenance outages
- Forced and maintenance derating of the Generating Facility
- Any non-production hours or standby loads

The Backcasting Tool outputs the hypothetical energy generation of the Generating Facility under certain weather conditions and Generating Facility operational status. Those outputs are then used throughout this Agreement to determine payments, shortfalls, dispatchability limits and damages (e.g. Un-Dispatched Amounts, Excused Product, etc.).
EXHIBIT 27

BACKCASTING TOOL GENERAL INPUTS

**Resource-Adjusted Backcast Amount** means an amount determined by the backcasting analysis that takes into account weather conditions including cloud cover, rain and snow impacting the solar resource, but assumes 100% mechanical availability of the Generating Facility.

**Availability Backcast Amount** means an amount determined by a backcasting analysis that takes into account both resource conditions and availability of the Generating Facility where availability, in this context, refers to the status of the Generating Facility’s mechanical and electrical systems and equipment (e.g. operational capability of inverters, converters, transformers, etc.). The Availability Backcast Amount may be adjusted downwards from the Resource-Adjusted Backcast Amount by the amount of capacity lost due to these systems and equipment being impaired for any reason that is not a cause of Excused Product, as defined in Section 3.6.6. This calculation will include Supplier-reported derates and real-time status signals and calculations performed at the Generating Facility that are communicated to the Energy Management System (EMS) such that the EMS can send Automatic Generator Control (AGC) signals that are within the actual plant and weather conditions of the Generating Facility (reference Exhibit 16 Dispatchable Accuracy Rate).

Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer.

If the Parties disagree on the calculation of the Resource Adjusted Backcast Amount or Availability Backcast Amount, then the Backcast Amount will be determined through the Dispute resolution provisions of Article 21.
REN-6-GS (b)
Technical Appendix REN-6-GS (b)

Summary of the Nevada Administrative Code sections applicable to Gemini Solar.

NAC 704.8885 (New renewable energy contracts: Review by Commission; criteria for approval) and NAC 704.8887 (New renewable energy contracts: Determination of whether price for electricity is reasonable) require that the Companies provide specific information regarding new renewable energy contracts for which they are seeking approval. The information responsive to NAC 704.8885 and 704.8887 is set forth below:

NAC 704.8885(2)(a) requires the Commission to determine the reasonableness of the price of electricity based on the factors set forth in NAC 704.8887, detailed in pertinent part as follows:

NAC 704.8887(1) instructs the utility to calculate the price for electricity acquired or saved pursuant to a new renewable energy contract or energy efficiency contract by calculating the levelized market price for the electricity.

The Levelized Cost of Energy ("LCOE") for the contract is $42.83/megawatt-hour ("MWh") including network upgrade costs. The rate is for the purchase of energy and portfolio credits ("PCs") at a blended rate, as well as the use and maintenance associated with the battery energy storage system.

NAC 704.8887(2)(a) requires the Commission to address whether the new renewable energy contract or energy efficiency contract comports with the utility provider’s most recently approved plan to increase its supply of or decrease the demand for electricity.

This project is being proposed as part of the third amendment to the Companies’ 2018 triennial integrated resource plan to increase its supply of electricity.

NAC 704.8887(2)(b) addresses the reasonableness of any price indexing provisions set forth in the new renewable energy contract or energy efficiency contract.

The price for renewable energy and PCs set forth in this contact is $24.79/MWh with no escalation for the term of the contract except during the hours ending 1700 through 2100 during the months of June, July and August when the price is $161.14/MWh.
The price for the storage portion of the PPA is included in the rates above for the term of 25 years.

NAC 704.8887(2)(c) addresses whether the new renewable energy systems will reduce environmental costs in this State as compared to competing facilities or energy systems that use fossil fuels.

The technology that the Gemini Solar project utilizes creates zero air emissions. When compared to a modern gas-fired combined cycle unit, the emissions avoided are shown in the table below.

<table>
<thead>
<tr>
<th>Project</th>
<th>SO2</th>
<th>CO</th>
<th>VOC</th>
<th>NOX</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gemini Solar</td>
<td>4.61</td>
<td>10.75</td>
<td>0.23</td>
<td>49.55</td>
<td>16.90</td>
</tr>
</tbody>
</table>

1 Avoided Emissions derived from average heat rate for a state of the art combined cycle unit. This is a conservative assumption as avoided emissions are likely to be from higher heat rate market purchases or from older, less efficient units.

The project uses de minimis amounts of water, creates no waste streams in its energy production and efficiently utilizes land for solar energy generation, and has minimal impacts on wildlife.

NAC 704.8887(2)(d) addresses the net economic impact and all environmental benefits and environmental costs to this State in accordance with NAC 704.9005 to 704.9525, inclusive.

According to the developer, the anticipated net economic impact of the project includes:

- A temporary increase in workforce during the construction phase of the facility of an estimated 2,385 positions;
- A permanent long-term increase in the workforce for the operation and maintenance of the facility of an estimated 25 positions at an estimated average salary of $79,000 annually, and a total payroll of $63.2 million over 25 years;
- The environmental benefit will be a reduction in air emissions as shown in the table above.
NAC 704.8887(2)(e) addresses any economic benefits that might inure to any sector of the economy of this State.

The economic benefits of the project include increased sales taxes from the purchase of local goods. Other benefits include an increase in short-term construction employment and long-term operations employment.

NAC 704.8887(2)(f) addresses the diversity of energy sources being used to generate electricity that is consumed in this State.

Commission approval of the PPA will increase the diversity of energy sources used to generate electricity that is consumed in Nevada. The portfolio of renewable energy will increase with a commensurate decrease in its reliance on fossil fuel generation.

NAC 704.8887(2)(g) addresses the diversity of energy suppliers generating or selling electricity in this State.

Solar Partners XI, LLC is a U.S.-based company, headquartered in Redwood City, CA. Its investor, Quinbrook Infrastructure Partners, has developed over 4GW of projects across the world, with a vast majority in the United States.

NAC 704.8887(2)(h) addresses the value of any price hedging or energy price stability associated with the new renewable energy contract or energy efficiency contract.

The agreement has a low starting price with no escalation over the term of the contract. The price is therefore known through the term of the contract and is not subject to fuel risk.

NAC 704.8887(2)(i) addresses the date on which each renewable energy system is projected to begin commercial operation.

The project’s commercial operation date is estimated to be December 1, 2023.

NAC 704.8887(2)(j) addresses whether the utility provider has any flexibility concerning the quantity of electricity that the utility provider must acquire or save pursuant to the new renewable energy contract or energy efficiency contract.
The agreement permits Nevada Power Company ("NPC") the flexibility to economically dispatch the facility. During the hours ending 1700 through 2100 in June, July and August, the agreement calls for NPC to take all net energy, including any excess energy and PCs generated by the facility. Curtailment or re-dispatch of up to 100 percent of the expected output can be ordered by the transmission provider, electric system authority, or market operator. NPC has no obligation to pay for generation in excess of the maximum amount. Excess energy is paid for at fifty percent (50%) of the applicable product rate. NPC has flexibility in operation of the battery storage system which can be dispatched at the discretion of the Company.

NAC 704.8887(2)(k) addresses whether the new renewable energy contract or energy efficiency contract will result in any benefits to the transmission system of the utility provider.

The Large Generator Interconnection Agreement ("LGIA") and System Impact Study ("SIS") for this project have been completed. The studies did not identify any negative impacts to NPC’s transmission grid that could not be mitigated by the transmission system additions proposed in the studies. The project generates electricity which will provide benefits to the transmission grid by providing real and reactive power at the point of interconnection. See Technical Appendices TRAN-3 and TRAN-4 for information on the LGIA and SIS.

NAC 704.8887(2)(l) addresses whether the electricity acquired or saved pursuant to the new renewable energy contract or energy efficiency contract is priced at or below the utility provider’s long-term avoided cost rate.

When compared to the long-term avoided costs approved by the Commission in Docket No. 18-06003, the blended rate for energy and PCs is lower than the long-term avoided costs in year 2023 and years 2033 through 2048.

NAC 704.8887(3) addresses the price of electricity acquired or saved in a renewable energy contract or energy efficiency contract for the solar energy requirement of its portfolio standard to be evaluated separately.

The cost of power and PCs delivered from the project are competitive to both the prices NPC pays for its current portfolio of renewable projects and the other compliant bids submitted in the Fall 2018 Renewable Energy RFP.

NAC 704.8885(2)(b) addresses the term of the contract.
The term of the PPA is 25 years.

NAC 704.8885(2)(c) addresses the location of the portfolio [renewable] energy system or efficiency measure that is subject to the contract.

The project is located approximately 25 miles northeast of Las Vegas near the Apex Industrial Park in Clark County, Nevada.

NAC 704.8885(2)(d) addresses the use of natural resources by each renewable energy system that is subject to the contract.

The project utilizes irradiance from the sun gathered by solar panels. No water is consumed during the operation of the project other than the occasional cleaning of the panels.

NAC 704.8885(2)(e) addresses the firmness of the electricity to be delivered and the delivery schedule.

The project generates non-firm energy that will be delivered into the utility’s grid which will be delivered through firm transmission pursuant to the designation of the facility as a network resource.

NAC 704.8885(2)(f) addresses the delivery point for the electricity.

The generating facility will be interconnected to the existing Crystal Substation. A one-line diagram depicting the interconnection can be found in Exhibit 5 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(g) addresses the characteristics of similar renewable energy systems.

The characteristics of the project are similar to those of NPC’s other large scale PV systems such as Boulder Solar I and Techren I. The plant design is proven technology. The storage portion consists of lithium-ion battery and inverter technology in use in utility scale applications.

NAC 704.8885(2)(h) addresses the requirements for ancillary services.

Requirements for ancillary services are not affected by the PPA.
NAC 704.8885(2)(i) addresses the unit contingent provisions.

The energy from the facility is contingent upon the availability of the unit. If the unit is not producing within the performance specifications of the PPA, then energy will be replaced from other sources.

NAC 704.8885(2)(j) addresses the system peak capacity requirements of the utility provider.

The power purchase agreement will provide benefits to the system peak capacity requirements of NPC.

NAC 704.8885(2)(k) addresses the requirements for scheduling.

All net energy from the facility will be delivered directly to NPC’s electric grid. The facility will be considered a network resource with NPC’s system and output from the facility will be used to meet its native load.

NAC 704.8885(2)(l) addresses conditions and limitations on the transmission system.

The LGIA for the 230-kilovolt (“kV”) portion of the facility has been executed and the SIS for the 525-kV portion of the facility is complete. Shared Network Upgrades associated with this project include a new 500-kV terminal position at the South Crystal substation, two 500-kV breakers and a new Harry Allen to Crystal 230-kV Line. This project will require transmission provider interconnection facilities, which includes associated protection, communications, and metering, that are directly paid for by the interconnection customer. The estimated cost for the shared Network Upgrades is $15,630,000.

NAC 704.8885(2)(m) addresses project insurance.

The PPA requires the supplier to provide workers compensation insurance of not less than $1 million per occurrence, general liability of not less than $5 million annual aggregate, and automobile liability insurance of at least $2 million aggregate.

NAC 704.8885(2)(n) addresses the costs for procuring replacement power in the event of non-delivery.

In the event the project does not meet certain performance requirements, the supplier is obligated to compensate NPC for shortfalls in energy and PCs. Compensation for an energy shortfall is based upon the difference between the cost of replacement power, as
specified in the PPA, and the PPA price. However, should the cost of replacement power be less than the contract price of power from supplier, the replacement cost will be $0.00. Compensation for a PC shortfall is determined by NPC exercising its reasonable discretion based on the estimated cost of purchasing PCs.

NAC 704.8885(2)(o) addresses information verifying that each renewable energy system transmits or distributes or will transmit or distribute the electricity that it generates in accordance with the requirements of NRS 704.7815, as amended.

The generating facility uses renewable solar energy to generate electricity and transmits that energy to NPC. Therefore, the generating facility comports with NRS §§ 704.7815(1)(a) and 704.7815(1)(b).

NAC 704.8885(2)(p) addresses the total number of renewable energy systems that the owner of the renewable energy system is or has been associated with as an owner or operator.

Solar Partners XI, LLC is a U.S.-based company, headquartered in Redwood City, CA. Its investor, Quinbrook Infrastructure Partners, has developed over 4GW of renewable projects across the world, with a vast majority in the United States.

NAC 704.8885(2)(q) addresses the points of interconnection with the electric system of the utility.

The generating facility will be interconnected to the existing Crystal 230-kV and Crystal 525-kV substations. A one-line diagram depicting the interconnection can be found in Exhibit 5 of the PPA.

NAC 704.8885(2)(r) addresses the interconnection priority which has been established for the available transmission capacity of the utility provider for all proposed renewable energy systems that will interconnect and begin commercial operation within the three-year period immediately following the date on which the new renewable energy contract or energy efficiency contract is submitted for approval.

Commission approval of the project will not affect any pending Federal Energy Regulatory Commission ("FERC") interconnection priorities. Pursuant to the provisions of NPC’s FERC-approved OATT, interconnection priority of a generator is determined based on the date the requesting customer submits a valid interconnection request.
NAC 704.8885(2)(s) addresses any requests for transmission service that have been filed with the utility provider.

A LGIA between NPC and Solar Partners XI was executed on June 11, 2018, for the 230-kV portion of the project. The in-service date is projected to be achieved October 1, 2020. An SIS for the 525-kV portion of the project was completed December 2018.

NAC 704.8885(2)(t) addresses any evidence that an environmental assessment, an environmental impact statement or an environmental impact report is being completed or has been completed with regard to the renewable energy system, or any evidence that a contract has been executed with an environmental contractor who will prepare such an assessment, statement or report within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation.

The facility and transmission are sited entirely on land managed by the Bureau of Land Management ("BLM"). The project will require preparation of an Environmental Impact Statement ("EIS") in compliance with National Environmental Policy Act ("NEPA") analysis. The BLM provided Gemini Solar with a schedule to have a Final EIS approved and Record of Decision ("ROD") in place by September 2019.

NAC 704.8885(2)(u) addresses permits required for the renewable energy systems within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation.

Permits necessary for the construction and operation of the Gemini Solar project are listed in Exhibit 10 and Exhibit 12 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(v) addresses applications for development rights with the appropriate Federal agencies (including BLM), where the granting of such developmental rights is not contingent upon a competitive bidding process.

Applications required from Federal agencies for the development of the Gemini Solar project are listed in Exhibit 10 and Exhibit 12 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(w) addresses any evidence that establishes rights of ownership, possession or use concerning land or natural resources, including, without limitation, deeds, land patents, leases, contracts, licenses or permits concerning land, geothermal drilling rights or other rights to natural resources.
The project developer, Arevia Power, obtained site control for the Gemini project through the NEPA BLM application process via Standard Form 299 (SF299). In April 2017, Quinbrook acquired Solar Partners XI, LLC, the entity that submitted the original SF299 to control the 44,000-acre Application Area.

NAC 704.8885(2)(x) addresses whether the utility provider has any economical dispatch rights.

The agreement permits NPC the flexibility to economically dispatch the facility. During the peak period hours ending 1700 through 2100 in June, July and August, the agreement calls for NPC to take all net energy, including any excess energy and PCs generated by the facility.

More On This Topic

Power Purchase Agreements: Utility-Scale Projects
Power Purchase Agreements: Utility-Scale Projects

I. The Revenue Stream. When a solar project is owned by an independent power producer rather than a utility serving its own load, the agreement that provides for an assured source of revenue from the energy output and related environmental attributes of the project is central to the project’s viability. In theory, the energy output of any resource—solar included—can be sold into the many local spot markets without a long-term output agreement on a “merchant” basis. In practice, however, the risk attendant to such merchant sales—where the project owner takes the prevailing market price at the point of interconnection—has proven too great to enable investors (and most developers, for that matter) to get comfortable that the project will be and remain economically viable. In part, this is due to the fact that such market prices are difficult to predict and tend, on average, to be lower than prices that would be available under a long-term power purchase agreement (“PPA”). In tight markets, the spot market can soar well above the long-term contract price, as it did in California circa 2001 or during the more recent Polar Vortex in the Northeast. Such spikes in market prices tend to not only be rare and short-lived (often lasting no more than a few hours during peak load times), but more importantly they are unpredictable, and thus cannot provide the requisite assurance that the project will produce sufficient revenues over time to maintain its economic viability.

As a result, the standard model for solar projects is to have some sort of output agreement that either provides for the long-term sale to a utility of the energy output (and associated environmental attributes) at a specified price or that provides a hedge against the price volatility inherent in the spot market. The primary vehicle used in this regard is a long-term (generally 20 years) PPA with an offtaker under which the offtaker agrees to purchase, at a specified price, all energy and related environmental attributes as and when the same are produced by the solar project. That offtaker is often a load-serving utility, but in
recent years large commercial and industrial customers have been significant players in the PPA arena in order to accomplish corporate renewable energy goals and/or hedge their own power costs.

Alternatively, in the organized energy markets, it is possible to protect against market price risk by entering into an energy hedge or a contract for differences ("CFD," also known as a virtual power purchase agreement ("VPPA")) with a creditworthy counterparty. Energy hedges and CFDs have some advantages over PPAs, and they are often favored by commercial/industrial offtakers because they avoid triggering state laws that may restrict direct retail sales—one of the reasons that CFDs and VPPAs are often the type of agreement preferred by corporate offtakers. They are not contracts where the "buyer" (i.e., the counterparty to the seller/solar plant owner) intends to use the energy to meet its own needs, as is the case with a utility under a PPA that is buying energy to meet its own load. As a result, in theory, the counterparty can be located anywhere, without regard to its needs for energy in the area in which the solar plant is located. This is how energy hedges expand the universe of possible counterparties beyond just load-serving utilities.

In this chapter we will explore the basics of these output agreements, with a focus on some of the key differences between traditional PPAs and CFDs that continue to be the principal output arrangement in solar energy.

A. The Parties.

1. The Seller. With few exceptions, the seller is a special purpose entity (often called an "SPV" or the "project company") that owns and operates the solar plant that will generate energy and environmental attributes ("output"). For a variety of reasons (e.g., limiting liability and having a tidy, "one-stop" security package for investors), such SPVs generally only own one asset: the solar plant in question. But the seller may also be a power marketer that is buying the output of a plant from the developer-owned SPV and reselling it to one or more purchasers. If the power marketer is reselling output, the resale PPA will usually track the relevant terms of the underlying PPA because the marketer will not want to promise more than it has the right to deliver. As a result, the marketer will often use a "back-to-back" PPA for the resale. The resulting terms will be almost the same as those in the underlying project PPA, except for price or other unique items that the marketer does not wish to pass through to the ultimate buyer.
In a tax equity financed project, the developer sells a substantial interest in the installation to an investor or utility before the installation is placed in service so that the developer can use the funds paid by the investor or the federal investment tax credits, federal accelerated depreciation, and any available state-level tax benefits to recoup all or a portion of its development costs. Because the market for tax credits remains uncertain, it appears that more developers are considering the use of debt financing as a critical component of the financing package.

2. The Buyer. The buyer is often a utility that purchases the solar project’s output to serve its load. Utilities tend to be the ultimate end-user of the output simply because, under the laws of most states, only regulated utilities can sell electricity to the end-user (e.g., a business, commercial, or residential user).¹

   a. But Utilities Are Not the Only Buyers. Power marketers may buy output for resale to one or more third parties. Power marketers sometimes can purchase all of a project’s output (something that no other single-market player may be able to do), taking a “merchant position” and enabling the owner to finance the plant. In addition, over the past several years, commercial/industrial customers (e.g., data centers) have entered into a substantial number of transactions for renewable energy. Due to legal restrictions that may prevent an end-use customer from directly purchasing renewable energy, transactions with commercial/industrial customers tend to rely on a variety of structures. These structures include direct retail sales where state law allows it, pass-through deals involving the local utility, financial arrangements that do not involve a physical delivery of power (including CFDs), and true wholesale deals where the commercial/industrial customer has the capability to operate in that market. Commercial/industrial customers also often demand different contractual terms than utilities, for accounting, public relations, or other reasons. We will get into some of these differences below.

3. Credit Support Provider. The PPA will require the offtaker to purchase the output that the seller delivers. It likely will also require the seller to pay the buyer if the project is not built on schedule or fails to achieve certain performance standards. Each party will be concerned about the other’s ability to satisfy these payment obligations. If one party is not creditworthy, the other may require it to provide a guaranty or post a letter of credit or other security
to ensure that amounts due under the PPA will be paid. In fact, it is only the rare offtaker that does not insist that the seller provide substantial security for its obligations under the PPA.

But it should be noted that this tends to be a one-way street in utility agreements: the seller posts security in favor of the offtaker, but the utility offtaker almost never posts security in favor of the seller. Traditionally, most offtakers do tend to be acceptable credit risks (most investor-owned utilities being rated in the “BBB” category, while most municipal utilities are rated “A” or higher), and their gross revenues in comparison to their liability under the PPA are more than adequate to give assurance that meaningful recourse can be had against the offtaker should it default in its PPA obligations. That said, offtakers that are not traditional utilities pose a different set of questions for sellers to consider when negotiating credit support terms. For example, sellers may wish to revisit the offtaker credit support question if the offtaker is a subsidiary of a large corporate offtaker without assets or a community choice aggregator with no credit rating and a short operating history. In some cases, an offtaker will not agree to post credit support up-front but may be obligated to do so if its credit rating falls below a negotiated threshold, such as investment grade levels.

Sellers are usually given the option of posting security in one of three forms: cash deposited in escrow, a letter of credit from a highly rated (“A” or better) bank, or a guaranty from a creditworthy entity. Except as a temporary expedient (e.g., while awaiting receipt of a letter of credit), cash is virtually never posted as security. It is simply too expensive to tie up such large amounts of cash and, in any event, an SPV that owns the solar plant generally is not cash rich (to the contrary—SPVs tend to be funded on a “just in time” basis by their parent). And because most solar plants are financed via tax equity investments where the tax equity investors will become equity owners of the SPV, sellers’ parents generally do not want to take on the additional risk inherent in being the source of the cash posted as security, but would prefer to have the SPV itself provide the security (and thereby share the cost of providing the same and the risks it entails with all the owners of the SPV, including the tax equity investors).

Guaranties from a creditworthy entity—usually the parent of the developer—are used in certain instances, but for reasons similar to those noted above in connection with cash deposits, are not the most favored form of security. From
a cost standpoint, one could assume that a guaranty is the least expensive choice, since it does not require forgone investment opportunities (as the posting of cash does) or an annual out-of-pocket fee (as does a letter of credit). But encumbering one’s balance sheet with a multimillion-dollar guaranty does, indeed, impose a cost on the guarantor in terms of the diminished credit capacity resulting from the contingent liability represented by the guaranty. In fact, in many large companies, there is an internal charge for such use of the company’s balance sheet. Furthermore, imposing the guaranty liability on the developer’s parent shifts part of the project risk from the SPV to the developer’s parent, and undermines the notion that all equity owners of the SPV (including tax equity investors) should share in the cost of doing business.

There is no universal standard for the amount of security that is required to be posted. In most PPAs, the security is divided into construction period security and security from and after the date the solar plant achieves commercial operation. In such cases, the construction period security is usually required in an amount equal to the per diem amount of any delay damages that may be owing if the seller does not achieve commercial operation by the target date set forth in the PPA, multiplied by the number of days between such target commercial operation date and the “drop dead” date (i.e., the date the utility can terminate the PPA if commercial operation has not yet been achieved). For the post-commercial operation security, the amount is usually set somewhere between six months and 18 months of expected payments under the PPA. However, where the PPA price is a “levelized” price throughout the entire term of the PPA (e.g., $27/megawatt-hour (“MWh”) for 20 years, as opposed to an inflating price of, e.g., $20/MWh in the first year, increasing at the rate of 2.5 percent per annum), occasionally, though not very commonly, the security amount increases over time until a certain “crossover” point is reached (usually between years 12 and 15 of a 20-year PPA). This approach is based on the theory that with a levelized price, the utility is paying more than it should in the early years and less than it should in the later years.

II. The Term. The term of the PPA has typically been around 20 years, to enable amortization of project debt and a period of return for the project sponsor. However, offtakers, particularly corporate offtakers, are increasingly requesting shorter terms, such as 15, 12, and even 10 years. Where the term is shorter, sellers will need to very carefully consider the expected financing model, especially if it is dependent upon expected returns after the end of the initial PPA term.
A. Effective Date. The PPA will be binding on the date it is signed (often called the “effective date”). This ensures that the offtaker will buy the output once the project is built and that the project owner will build the project and not sell its output to anyone other than the purchaser.

B. Commercial Operation Date. The term of the PPA usually begins on the effective date, but the length of the term is often defined by reference to a “commercial operation date.” For example, the term might end on the 20th anniversary of the January 1 following the commercial operation date. In other PPAs, the delivery term begins on the commercial operation date and extends for a specified number of years.

The commercial operation date often starts the PPA’s delivery term, determines whether the project has avoided liquidated damages by achieving its “guaranteed commercial operation date,” and establishes the point at which the price switches from a “test energy rate” to a “contract rate.” It is therefore important to define “commercial operation date” carefully. Generally, “commercial operation date” can be defined as the date on which all or some specified portion of the project and all other portions of the project necessary to put it into operation with the interconnection facilities and the transmission system have been tested and commissioned, and are both authorized and able to operate and deliver energy to the transmission system in accordance with prudent utility practices. The parties often negotiate more specific standards for judging whether commercial operation has been achieved and occasionally require that an independent engineer be engaged to make findings that support the achievement of commercial operation.

In most cases, “commercial operation date” is defined in a manner that allows the project owner to achieve commercial operation even if it has installed fewer than all of the solar units called for by the PPA. For example, the PPA may call for an installed capacity of 50 MW, but the commercial operation date may occur when 45 MW of capacity have achieved commercial operation (i.e., when the project has been “substantially completed”). Such PPAs typically require the seller to continue building the project until all of the project’s installed capacity has achieved commercial operation. If the seller achieves commercial operation for substantial project completion but thereafter fails to complete the remainder of the project, it may be liable to the buyer for liquidated damages for the incomplete capacity. A developer’s ability to declare commercial operation with respect to a portion of the project’s
expected installed capacity may also be useful to the developer in situations where partial force majeure, delayed interconnection, or an unanticipated permitting or land issue might create a problem as it relates to timing issues around the investment tax credit.

C. Termination Before the Commercial Operation Date. PPAs usually include “off-ramp” provisions that enable the offtaker to terminate the PPA if certain events occur or fail to occur. Perhaps the most common provision for early termination includes the failure of a public utility commission to approve a PPA or to allow its costs to be passed through to ratepayers. Developers should carefully consider the timing of the expected development costs it will incur to advance the project while the buyer retains an ability to terminate. In other words, a developer should not be required to incur substantial development costs, and certainly not to start construction, prior to the time in which the buyer is bound by the PPA. Accordingly, a buyer’s termination right associated with commission approval should have an end date so that the developer can adjust its schedule accordingly. In the not-too-distant past, developers could also obtain early termination rights for reasons such as the failure to obtain reasonable financing. But such termination rights in favor of developers are becoming increasingly rare, as offtakers expect developers to be experienced and to take on the risks of project development. Other early termination rights that may be available are a seller’s inability to obtain interconnection on acceptable terms, particularly costs and timing, consistent with the seller’s expectations and the inability or delay in obtaining permits required to build or operate the project. In cases where the buyer can invoke a termination right after the seller has exhausted its right to pay delay damages, careful attention should be paid to limiting the developer’s liability and the purchaser’s remedy to the delay damages already paid to the buyer or to some other clearly defined payment.

III. Purchase and Sale.

A. Delivery Point. The PPA will require the sale of energy to occur at a specified delivery point. If the energy is to be delivered at the plant in a “busbar” sale, the delivery point will usually be the high side of the transformer at the project’s substation. In a busbar transaction, the buyer provides the transmission required to transmit the energy from the plant to the point where the buyer intends to use it (or to deliver it to another party in a resale transaction). The PPA may also require the seller to provide necessary and
adequate transmission to take the energy away from the project’s busbar or otherwise assign to the seller the curtailment risk associated with inadequate transmission away from the project. Alternatively, the PPA may also require the seller to deliver energy to a specific point some distance from the plant, in which case the seller will be responsible for securing the required transmission to the delivery point, and the buyer will be responsible for obtaining the transmission required to take the energy at the delivery point. Transmission ancillary services can be fairly costly and should be specifically allocated in the agreement. Title and risk of loss pass from seller to buyer at the delivery point. In a VPPA, energy is not actually delivered to the offtaker. Instead, energy is typically sold into the energy market with which the project is interconnected.

B. Pricing.

1. Contract Rate. Price is usually the most important part of the PPA. The price may be flat, escalate over time, or contain other features. An escalating price is often tied to a “contract year” that begins at a specified point after the commercial operation date is achieved, thus encouraging the seller to lock in the initial price and the escalation rate by achieving commercial operation as soon as possible.

2. Test Energy Rate. Because an electrically distinct array (panels behind a single inverter) can generally function independently of other arrays, the PPA may require the purchaser to buy power from the arrays as they are installed, connected to the transmission grid, and made operational, even though the project as a whole has not achieved commercial operation. To encourage the seller to achieve commercial operation as soon as possible, such energy is often sold at a test energy rate, which is lower than the contract rate that will be paid once the commercial operation date is reached. However, in Independent System Operators (“ISO”)/Regional Transmission Organizations with energy markets (e.g., the Midcontinent ISO), the seller may choose to sell its test energy into the market rather than to the purchaser, or alternatively the purchaser may pay the market rate for test energy.

3. Excess Rate. A PPA often requires the seller to specify how many MWhs the plant is expected to produce each year. This output estimate may form the basis of an output guarantee or a mechanical-availability guarantee. To encourage the seller to make an accurate estimate of expected output, the seller may be paid less than the contract rate for each MWh of energy in excess of, for example, 110 percent of the estimated annual output.
4. Fixed for Floating Pricing. While there are a number of different variations for how a fixed for floating price can be structured, the general concept is that the offtaker agrees to guarantee to the developer a fixed price per MWh of metered energy. A developer delivers energy from the project into the energy market, either the day-ahead or real-time market, and receives the locational marginal price (“LMP”) revenue (or pays the LMP cost for negative LMP) (in either case, the floating price) to the ISO in connection with such metered energy. Over an agreed-upon time period, the parties compare the floating prices to the fixed price and a payment is made to or from the offtaker so that the end result is the developer receives no more or less than the fixed price per MWh. Variations of this structure include determining which market the seller will participate in (day-ahead or real-time) and which LMP price is used to set the floating price (the project’s PNode LMP or a more liquid Hub within the energy market). If a Hub price is used, a developer must understand and mitigate the basis risk (or price differential risk) between the project’s LMP and the Hub price that it is taking. In addition, the offtaker will typically want to limit its exposure to negative floating prices. This is often accomplished by setting a negative LMP floor price, below which the project is deemed to have no metered quantity, and a seller is instead paid based on the forecasted volume for such interval multiplied by an amount equal to the contract price minus the floor price.

C. Environmental Attributes. Environmental attributes are the credits, benefits, emissions reductions, environmental air-quality credits and emissions-reduction credits, offsets, and allowances resulting from the avoidance of the emission of a gas, chemical, or other substance attributable to the solar project during the term of the PPA, together with the right to report those credits. Environmental attributes are sometimes called “green tags,” “green tag reporting rights,” or “renewable energy credits” (“RECs”). The PPA should make it clear that production tax credits, solar energy incentives (such as those that may be provided under a state program), and any other environmental attributes necessary to generate the quantity of power being sold to the purchaser are not part of the environmental attributes and thus are not being conveyed to the purchaser.

The PPA should clearly state whether energy is being sold with or without the environmental attributes. Failure to do so can (and has) led to disputes about whether the generator or the offtaker is entitled to the ownership and use of the environmental attributes. If environmental attributes are being sold, the
seller will usually warrant title to the attributes but will not universally warrant the current or future use or value of the attributes or whether and to what extent they will be recognized by law. Instead, the seller will often agree to spend up to a negotiated amount of money (either annually and/or in total) to maintain the value and use of environmental attributes. Once that financial cap is reached, the seller is under no further obligation to spend money in an effort to shield an offtaker’s environmental attributes from a change in law. As a result, the purchaser assumes some risk that the law or the market might change in a way that reduces the value of the environmental attributes.

D. Allocation of Taxes and Other Charges. The PPA should specify who pays any sales, excise, or other taxes arising from the transaction. Although most states do not tax wholesale energy sales, the parties may wish to consider allocating the tax liability that might result from future legislation.

IV. Permitting and Development.

A. Commitment to Develop. The PPA will make the project owner responsible for developing and constructing the project. The seller usually prefers a PPA that requires it to sell the project’s output only if the project is actually built. A buyer tends to view such a PPA as a put and will usually insist that the seller make some commitment to develop the project. Many negotiations revolve around what the seller will or will not be required to do to develop the project, as well as the off-ramps that each party has if the project does not achieve certain stated milestones.

B. Status Reports. The buyer is typically interested in the ongoing development of the project because it needs to know when the energy will be delivered onto its system or when it will need to take a hedge position. As a result, the PPA usually requires the seller to deliver regular reports to the buyer about the status of permitting and construction.

C. Milestones and Delay Damages. The PPA often includes a schedule of certain project milestones (e.g., the date by which the seller must secure project financing, the date by which equipment must be ordered, the date by which all permits and the interconnection agreement must be in place, and the commercial operation date). If the seller fails to achieve a milestone, the buyer may have a right to terminate the PPA, collect delay damages, or require the seller to post additional credit support. The seller will therefore want to limit the number of milestones and bargain for some flexibility, especially in
cases when a delay in achieving an interim milestone is not likely to delay a project’s completion date. Sellers would prefer PPAs that provide that the buyer’s only remedy if the seller fails to meet a project milestone is to terminate the PPA without recovering damages; however, it is very rare that a PPA provides for termination without damages. Buyers are concerned that this gives the seller a right that resembles a put and strongly prefer to require the seller to suffer some consequences if project milestones are missed. Many interesting negotiations revolve around the off-ramps that the seller will have versus the damages it will pay to the buyer if it fails to build the project in accordance with the PPA. A common middle ground is for the seller to agree to pay delay damages up to an agreed-on cap (often the credit support posted by the seller during development), which defines the limits of the seller’s exposure if the project is not built but gives the seller an incentive to use diligent efforts to finish the project on time.

V. Interconnection and Transmission. The PPA will require the seller to bear the cost of interconnection (including any network upgrades required by the new project) and all costs of transmitting the energy to the delivery point. If the seller is the project owner (as opposed to a marketer), it will also be responsible for negotiating the interconnection agreement with the transmission provider. The buyer will be responsible for arranging and paying for transmission from the delivery point. (For more information on interconnection and transmission-related issues, see Chapter 5.)

VI. Performance Incentives. Although a seller would prefer to enter into an “as-delivered” PPA, which means that the seller is obligated to deliver only what the project actually produces, PPAs today will require the seller to warrant or guarantee that the project will meet certain performance standards. Such guarantees usually enable the buyer to recover all or part of its incremental cost of purchasing replacement power and environmental attributes in the market to the extent that the project fails to perform as expected. Performance guarantees enable the buyer to plan around the plant’s expected output for both load and, if applicable, renewable-portfolio standard compliance, and strongly encourage the seller to maintain a reliable and productive project.

A. Output Guarantees. The PPA may include an output guarantee to the buyer. An output guarantee requires the seller to pay the buyer if the project’s output over a specified period fails to meet a specified level, after taking into
account output lost because of force majeure or maintenance or other agreed-on subtractors. The period may be seasonal, annual, biannual, or longer (although seasonal guarantees are unusual in today’s PPA market). The PPA usually allows the owner to operate the project for one or two years before the output test is applied, enabling the owner to fix any problems at the project, and may calculate the guarantee on a two-year rolling average to minimize the impact of particularly low or high solar irradiation years. Some output guarantees, however, are calculated and compensated annually, as buyers now expect greater precision from developers.

**B. Availability Guarantees.** An availability guarantee requires the solar arrays in the project to be available a certain percentage of the time, after excluding hours lost to force majeure and a certain amount of scheduled maintenance. Mechanical-availability percentages usually range from 90 percent to 95 percent, but they may decline over the life of the project or even disappear altogether during the final years of the PPA term to reflect wear and tear on the panels. Mechanical-availability guarantees are quite rare in today’s PPAs, particularly where the offtaker is a load-serving utility. But mechanical-availability guarantees continue to have their place in PPAs where the offtaker is a corporate or industrial user, due to accounting issues that cause these offtakers to prefer an availability guarantee over an output guarantee.

**C. Liquidated Damages.** If a guarantee is not met, the PPA usually provides a mechanism for determining the damages suffered by the buyer. First, the parties determine the output shortfall (stated in MWhs) relative to the amount of output that the buyer would have received had the project lived up to its guarantees. Second, the shortfall is multiplied by a price per MWh determined by reference to an agreed-on index or a fixed price (a liquidated damage for shortfalls). Because market indexes currently cover only power prices and do not include the value of environmental attributes, the PPA may include an adjustment to account for the assumed value of the environmental attributes or may use a firm price index as a proxy for the value of the energy plus the environmental attributes. The amount of liquidated damages is usually determined once per year. The seller pays the liquidated damages to the buyer or credits the damages against amounts owed by the buyer under the PPA. The seller may in addition seek to include the right to cure any output shortfall through delivery of replacement energy and environmental attributes at its option where the seller and the buyer can mutually agree on the time and place for such replacement deliveries. In any case, the seller will likely seek
to cap liquidated damages or its replacement obligation on an annual or aggregate basis.

**D. Termination Rights.** To protect against chronic problems at an unreliable solar plant, the PPA may allow the buyer to terminate the PPA if the output or mechanical availability of the project is below a stated minimum for a certain number of years.

**VII. Curtailment and Force Majeure.**

**A. Curtailment.** The PPA often describes circumstances in which either party has a right to curtail output. For example, the seller may have a right to curtail deliveries if the plant is affected by an emergency condition. The PPA may permit the buyer to curtail for convenience or what is often referred to as “economic curtailment,” in which case the PPA usually requires the buyer to pay the purchase price for the curtailed generation. In organized markets, where the offtaker is also the scheduling coordinator for the facility and in which generation dispatch by the ISO is affected by the bid curves submitted by the scheduling coordinators, it is important that the PPA indicate that curtailment caused by the offtaker’s bidding strategies are deemed to be economic, and therefore compensated, curtailments. However, buyers often negotiate the right to a certain amount of uncompensated curtailment. Facility curtailments caused by transmission congestion or conditions beyond the point of delivery are often allocated to the seller, although the topic of curtailment is frequently a difficult issue in PPA negotiations.

**B. Force Majeure.** If energy is curtailed at a party’s discretion (above any allowed uncompensated amount) or because the party is at fault, the PPA usually requires the curtailing party to pay damages to the other. If curtailment is caused by an event beyond a party’s control, the party’s duty to perform under the PPA may be excused. For example, if a natural disaster disables a transformer at the facility, the seller would be excused from delivering energy, and the buyer would be excused from taking and paying for energy, until the transformer is repaired. The party responsible for maintaining the transformer would, of course, be required to use diligent efforts to make repairs.

**1. Parties Often Heavily Negotiate Force Majeure Provisions.** Good provisions should carefully distinguish between events that constitute “excuses” (which relieve the affected party from its duty to perform) and those
that are “risks” (which are simply allocated to a party). The ability to buy energy and environmental attributes at a lower price or sell them at a higher price is not a force majeure event. Moreover, a party’s inability to pay should not constitute a force majeure event under the PPA. A well-drafted force majeure clause will usually list a number of items that both parties agree are force majeure events, as well as list items that the parties agree are not force majeure events.

**VIII. Defaults and Remedies.** The PPA will usually list events that constitute defaults. These may include:

- failure by any party to pay an amount when due;
- other types of specified material defaults;
- the bankruptcy, reorganization, liquidation, or other similar proceeding of any party; or
- failure to provide or replace credit support within an agreed-on time.

The default clause should specify how long the defaulting party has to cure a default. If the default is not cured within the agreed-on period, the nondefaulting party usually has the right to terminate the agreement and pursue its remedies at law or in equity or to suspend performance of its obligations. The remedies clause may also limit remedies or place a cap on the seller’s damages, although a cap on damages usually, but not always, applies to only those events of default occurring before the commercial operation date. It is worth noting, however, that where a seller’s damages are capped after the commercial operation date, the offtaker typically has a right to terminate the PPA if the seller will not agree to continue paying damages, so the cap may be nominal only.

**IX. Project Lenders and Equity Investors.** Even if the project is expected to be financed off a developer’s balance sheet, the terms of the PPA will usually take into account the possibility that the PPA will be assigned to a lender as collateral for project debt. The PPA will therefore contain provisions authorizing the seller to assign the PPA as collateral; requiring the buyer to provide consents, estoppels, or other documents needed in connection with financing; and giving the lender various protections (including additional time to cure defaults). The PPA may also include provisions to address the concerns and cure rights of future tax equity investors and should allow in the PPA or any form of consent transfers associated with exercise of remedies by lenders.
X. Buyer Options to Purchase the Project or Special Purpose Entity. Many utilities have shown a strong interest in owning solar energy projects. In PPAs, this interest often takes the form of an option to purchase the project or the entity that owns it on or after a specified date. Such options should be handled carefully. An option to purchase the project or the interests in the special purpose entity that owns the project for anything other than the project or entity’s fair market value at the time of exercise has been generally disfavored by tax attorneys. Other types of options can raise a fundamental question as to whether the owner of the project is an owner for federal income tax purposes or whether the financing arrangement is something other than “ownership” (e.g., a loan). Revenue Procedure 2007-65, 2007-2 C.B. 967, explicitly provides as one of the qualifying elements that there is no developer/investor/related party purchase option for less than fair market value (at exercise). Developers should ensure to carve out transfers associated with financing arrangements (tax equity investment, lender exercise of remedies) from right of first offer structured options.

A. Basic Structure of Hedge Arrangement. The essence of energy hedges and CFDs is that the parties agree upon a price (typically referred to as the “strike price”) for the energy produced. If, at the time the energy is produced, the market price at the point of interconnection with the transmission grid (or at an agreed-upon pricing node on such transmission grid) exceeds the strike price, then the solar plant owner pays the hedge counterparty an amount equal to the difference between such market price and the strike price. Conversely, if the market price is lower than the strike price, the hedge counterparty pays the solar plant owner the difference between the market price and the strike price. In this way, the solar plant owner is assured that it will receive the strike price for all energy covered by the hedge, and thus have an “output arrangement” that provides some revenue certainty in a manner similar to a PPA. The hedge counterparty reaps its return by endeavoring to structure the terms of the hedge such that, in the market in which the hedge plays out, the market price for energy is likely over time to exceed the strike price, thus producing the desired profit or return.

The actual energy produced that is subject to the hedge is often sold into the local market at the prevailing nodal price. But a hedge can be structured to give the counterparty the option of picking up the energy at the interconnection point (or even perhaps at some remote point agreed upon the parties, if transmission to that point is available) so that it can resell it in
bilateral sales to third parties. The motivation for such sales to third parties can be either the anticipation of a price higher than the prevailing market price or a more certain price that eliminates the risk inherent in market price volatility.

Where the energy is sold into the local market, the hedge is a pure financial transaction that is basically the same as an interest rate swap, with the strike price and market prices for the energy substituting for the “strike price” interest rate and interest rate indices used in interest rate swaps. In the event that the energy is physically delivered to the counterparty for resale, it takes on added elements similar to a PPA in certain respects. Note that where the hedge is a pure financial transaction, securing transmission to deliver the power to load is not required. But transmission considerations can still play a key role, as the location of the solar plant may be such that it is on the wrong side of a grid congestion point, thus adversely affecting the market price of the power and thereby affecting the economics (and perhaps even the availability) of the hedge.

The hedge does not always cover 100 percent of the energy anticipated to be produced by the solar plant. Rather, it is sometimes structured to be a certain percentage of the output, with the remainder being reserved to be sold on a merchant basis. The amount of production excluded from the hedge is based on a calculation by the concerned parties (the developer, financing parties, and the hedge provider) of the amount of risk the merchant piece entails and the likelihood that the merchant portion will jeopardize the project’s financial viability under certain conservative operating scenarios. In a variation, rather than reserving a certain percentage of the energy, these arrangements are sometimes structured to allow the developer to withdraw all or a portion of the energy produced during certain periods of the year.

Finally, unlike a PPA where the purchasing utility typically takes the environmental attributes (i.e., green tags or RECs) associated with the energy purchased and pays a single “all-in” price for both the energy and the environmental attributes, most energy hedges do not act to transfer the environmental attributes to the hedge provider. Rather, the environmental attributes are most often retained by the special purpose vehicle that owns the project and can serve as an added revenue stream (albeit one that is not given much value in the financing process due to the uncertainty as to the value of the environmental attributes over time).
However, it is possible to bundle the energy and environmental attributes under an energy hedge in the same manner as is done under PPAs. The context in which such a bundled arrangement is likely to be desirable is where a major commercial or industrial user acts as the hedge counterparty with a view to both “greening up” its own load and also providing itself with a hedge against rising energy prices in the markets in which it purchases energy to serve its own load. By entering into such a bundled hedge, the industrial or commercial counterparty gets to claim the environmental attributes and obtain whatever credit might be available to it in terms of public relations and perhaps in terms of meeting certain legal requirements relating to emissions. And by locking into a fixed strike price for an extended term, the industrial or commercial counterparty has reasonable prospects of being the net beneficiary of payments under the hedge as market prices rise over time, thus providing a hedge against similar rising prices of the electricity it purchases from third parties to serve its own load.

**B. Other Terms and Conditions.** Like the security a developer is required to post under a PPA, developers are also required to post substantial security to secure hedge obligations. The security most often takes the form of a letter of credit, but guarantees from a large balance sheet parent with good credit can also work. The amount of security required to be posted is determined in a manner similar to that under PPAs, based on the hedge counterparty’s assessment of its exposure given the nature of the project and the market in which the hedge is settled.

Unlike a PPA where, in the ordinary course, it is the utility that is expected to pay the developer, energy hedges will routinely require the developer to make payments to the hedge provider when market prices exceed the strike price. As a consequence, the right to project cash flows as among the hedge provider, lenders, and other project participants can be more complicated than in other circumstances not involving a hedge. In general, because the hedge serves the “revenue assurance function” that a PPA serves in other contexts, the hedge provider typically has paramount rights to project cash flow. The reason is simple: if the hedge provider is not timely paid what it is owed, the hedge can be subject to termination. And termination of the hedge would be a disaster akin to the termination of a PPA.

**C. Regulatory Considerations.**
A unique regulatory requirement that applies to energy hedges but not to PPAs is the Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 2010 U.S.C.C.A.N. (124 Stat.) 1376 (the “Act”), which is administered by the Commodity Futures Trading Commission (“CFTC”). While the provisions of that Act are complicated, suffice it to say that energy hedges are “swaps” within the meaning of the Act\(^2\) and as a result it may be necessary to comply with the registration, recordkeeping, reporting, and clearing requirements of the Act.\(^3\) In most cases, the reporting requirements will be imposed on the hedge provider, which is likely a “swap dealer” within the meaning of the Act. However, if the hedge provider is a swap dealer and the developer is a “major swap participant” (unlikely in this context, but possible), or if neither entity is a financial entity, swap dealer, or major swap participant, then the parties may agree between themselves as to which will comply with the recordkeeping and reporting requirements.

**XI. Retail Sales Structures.** As renewable portfolio standard demand has dipped in recent years, utility renewable procurements have, to some extent, slowed as well. However, the waning of utility demand has not, in all cases, corresponded to a lack of demand for renewable energy from customers directly. Accordingly, another option available to developers in some states is a direct sale to the end-user of energy (retail sale). This structure is particularly attractive to customers motivated by the desire to serve their loads with green power directly. The number of structures available for this type of sale varies depending on the size of the project and the jurisdiction in which the sale will take place.\(^4\)

Generally, sales of energy directly to the end-user are regulated by state utility commissions as opposed to the regulation of wholesale power sales that is within the purview of the Federal Energy Regulatory Commission. Historically, the seller of energy to a direct end-user was regulated as a public utility under state laws, typically, by the state utility commission. Moreover, in many jurisdictions, in order to incent such public utilities to make the necessary investments to serve retail end-users, public utilities were granted an exclusive right to serve the customers within the service territory granted to such public utility (\textit{i.e.}, the franchise). Without legislative changes to this typical legal structure, a direct sale to an end-user might have two unintended consequences to the solar energy developer: (1) the solar energy developer may find itself regulated as a public utility under state law (including a requirement to justify its rates for the sale of energy on a cost basis); and (2) it
may find its sale to be in violation of the exclusive franchised service territory of the incumbent utility.

As a result, the key hurdle a developer must overcome in determining whether a retail sales model is available to it is whether the state regulations and laws would permit such a sale. The answer to the question varies a great deal from state to state.

Other approaches enabling direct sales that vary depending upon jurisdiction include an exemption for certain small projects (i.e., net energy metering arrangements) from rate regulation (though safety regulation may still apply) or an exemption for a developer making sales from any renewable facility to an end-user from regulation as a public utility. Yet another approach enabling direct sales is to permit sales from one affiliate to another, provided the sales are on adjacent property. The key inquiry for the prospective seller is what types of structures (and at what sizes) may be permissible under the state law.

While beyond the scope of this chapter, if the generation facility is remote from the retail load, the developer interested in direct retail sales will also have to understand the options available to it for utilizing the transmission infrastructure to deliver the energy directly to the end-user as the ability to use the transmission grid for retail wheeling is limited in many areas.

If the developer can overcome these obstacles, then the retail sales structure for direct sales to the consumer is, in many ways, much like the typical PPA, with many of the same considerations previously discussed in this chapter, including price, term, credit requirements, performance guarantees, and default terms. However, the developer may find itself grappling with some additional issues as well. For example, where the customer may still need some service from the utility, the quality of the service to the customer may impact the retail customer in ways that increase costs to such customer. The local utility may charge, for example, a standby rate to the customer for the costs to the utility of “standing by” to serve the customer in the event that the intermittent solar generation is not produced. These costs can be unexpectedly high and the developer should consider the rate impacts to the customer in various jurisdictions in developing its origination strategies. Another issue sometimes encountered in the direct end-user sales structures is addressing a desire of the customer to include a termination for convenience clause in which the customer would have a right to terminate the
contract (typically with a negotiated termination payment) in connection with business interruptions, e.g., corporate shutdowns.

In short, developers will be well served to understand how the regulatory landscape in target jurisdictions may offer other sales options besides direct sales to the utility.

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1 A sale of electricity to the ultimate user of the power (such as a business, commercial, or residential user) is called a “retail sale.” A sale of electricity to a party that is not the ultimate user of the power but that intends to resell it to a third party is called a “wholesale sale.”

2 Although the CFTC has the authority to exempt, via regulation, certain swaps from the purview of the Act.

3 As of March 1, 2014, energy commodity swaps are not required to be cleared under the Act.

4 While net-metering arrangements offer one avenue for direct sales in some jurisdictions, given the size of the projects typically eligible for net-metering arrangements, these structures are not discussed in detail in this section. See Chapter 2 for more information on net-metering arrangements.

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In the Matter of the Application for Site Certificate
For the Bakeoven Solar Project

January 2020

BEFORE THE
ENERGY FACILITY SITING COUNCIL
OF THE STATE OF OREGON

DRAFT PROPOSED ORDER ON
APPLICATION FOR SITE
CERTIFICATE

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ACRONYMS AND ABBREVIATIONS
AC Alternating Current
ASC Application for Site Certificate for the Bakeoven Solar Project
BMP Best Management Practice
BPA Bonneville Power Administration
Council Oregon Energy Facility Siting Council
dBA A-weighted decibel
DE Department Oregon Department of Energy
DEQ Oregon Department of Environmental Quality
DOGAMI Oregon Department of Geology and Mineral Industries
DSL Oregon Department of State Lands
EFSC Oregon Energy Facility Siting Council
ESCP Erosion and Sediment Control Plan
EFU Exclusive Farm Use
HMP Habitat Mitigation Plan
kV Kilovolts
Li-ion Lithium Ion
MW Megawatt(s)
NPDES National Pollutant Discharge Elimination System
O&M Operations and Maintenance
OAR Oregon Administrative Rule
ODFW Oregon Department of Fish and Wildlife
ODOE Oregon Department of Energy
ODOT Oregon Department of Transportation
ORBIC Oregon Biodiversity Information Center
ORS Oregon Revised Statutes
pASC Preliminary Application for Site Certificate
RAI Request for Additional Information
SAG Special Advisory Group
USFS United States Fish and Wildlife Service
WCLUDO Wasco County Land Use and Development Ordinance
I. INTRODUCTION

The Oregon Department of Energy (Department) issues this draft proposed order (DPO) in accordance with Oregon Revised Statute (ORS) 469.370(3), based on its review of the Application for Site Certificate (ASC) for the proposed Bakeoven Solar Project (proposed facility) and comments and recommendations received by state agencies, local governments, and tribal governments. This DPO includes recommendations of approval for inclusion in the site certificate to ensure or maintain compliance with applicable rules and standards during proposed facility construction, operation and retirement. Based upon its review, including recommending findings of fact, conclusions of law and conditions, the Department recommends Council approve the ASC and issue a site certificate for the proposed facility.

The applicant, Bakeoven Solar, LLC (applicant), a wholly owned subsidiary of Avangrid Renewables, LLC, seeks Energy Facility Siting Council (EFSC or Council) approval to construct and operate a solar photovoltaic energy generation facility, and related or supporting facilities including an approximately 11-mile 230 kilovolt (kV) transmission line; a collector substation; an operations and maintenance building; communication and supervisory control and data acquisition (SCADA) system; site access, internal service roads, 8-foot perimeter fencing, and gates; temporary staging areas, and up to 100 MW of either lithium-ion or flow battery storage system. The proposed facility would occupy up to 2,717 acres on Exclusive Farm Use (EFSC) land, predominately composed of soils in capability class III (approx. 2,518 of 2,717 acres), as specified by the National Cooperative Soil Survey (operated by the Natural Resources Conservation Service of the United States Department of Agriculture).

As further described in this order, the applicant seeks approval of a microlinting corridor containing approximately 2,717,160 acres – a microlinting corridor, if authorized by Council, grants approval for siting of facility components anywhere within. Therefore, the extent of potential impacts for the proposed facility is based on occupation of up to 2,717 acres anywhere within the 4,160 acre microlinting corridor, all of which is within Exclusive Farm Use (EFSC) land, with 3,664 acres composed of soils in capability class III. The proposed facility would be located within southeastern Wasco County, approximately 5 miles east of the City of Maupin and U.S. Highway 97, and, 5 miles south of State Highway 216. The proposed facility would be capable of generating approximately 330 megawatts (MW) of electricity.

The proposed facility is subject to EFSC review pursuant to ORS 469.300(1)(a)(A)(6) as it is proposed as a solar photovoltaic power generation facility that would use more than 1,280 acres of land predominately composed of soils in a capability class I to IV, as specified by the National Cooperative Soil Survey. Approval of a site certificate by EFSC is therefore required for the construction, operation, and retirement of the proposed facility.¹

¹ The definitions contained in ORS 469.300 and Oregon Administrative Rule (OAR) 345-001-0010 apply to terms used in this DPO.

² ORS 469.330.

III. PROCEDURAL HISTORY

In addition to the conditions recommended in this DPO, the applicant would be subject to the conditions and requirements contained in local ordinances or rules on the date the preliminary application was submitted and the rules and standards of the Council and state laws in effect on the date the site certificate is executed. Under ORS 469.401(2), the site certificate shall require the applicant to abide by local ordinances and state laws and the rules of the Council in effect on the date the site certificate is executed. In addition, the Council may require compliance with later-adopted laws or rules upon a clear showing of a significant threat to public health, safety, or the environment that requires application of later-adopted laws or rules, the Council may require compliance with such later adopted laws or rules. The Department recognizes that many specific tasks related to the design, construction, operation, and retirement of the proposed facility would be undertaken by the applicant’s agents or contractors. Nonetheless, the certificate holder remains responsible for ensuring compliance with all provisions of the site certificate.

The Council does not have jurisdiction over matters that are not included in and governed by the site certificate or amended site certificate, including design-specific construction or operating standards and practices that do not relate to siting, as well as matters relating to employee health and safety, building code compliance, wage and hour or other labor regulations, or local government fees and charges. Also outside the Council’s jurisdiction are matters of land acquisition, land purchases, land leases and right-of-way easements.

A site certificate is a binding agreement between the State of Oregon and the applicant, authorizing the applicant to design, construct, operate, and retire a facility on an approved site, incorporating all conditions imposed by the Council on the applicant.¹ A site certificate issued by EFSC binds the state and all counties, cities and political subdivisions of Oregon. Once EFSC issues a site certificate, any affected state agency, county, city or political subdivision with an applicable permit identified in the ASC and to be governed by the site certificate, must, upon submission by the applicant of the proper applications and payment of the proper fees, but without hearing or other proceeding, promptly issue the permit, licenses and certificates addressed in the site certificate. The Council has continued authority over the site for which the site certificate is issued and may inspect, or direct Department staff to inspect, or request another state agency or local government to inspect, the site at any time in order to ensure that the facility is being operated consistently with the terms and conditions of the site certificate.²

¹ ORS 469.401(4).

² ORS 469.330(26).

³ ORS 469.401(5).

⁴ ORS 469.430.
On November 2, 2018, the Department received a Notice of Intent (NOI) from Bakeoven Solar, LLC (applicant) to file an application for site certificate (ASC) for a proposed 303 megawatt (MW) solar photovoltaic energy facility. On November 16, 2018, the Council appointed the Wasco County Board of Commissioners as the Special Advisory Group (SAG) for siting proceedings associated with the proposed facility, in accordance with ORS 469.480(1). On November 28, 2018, the Department issued public notice of the NOI to the Council’s general mailing list and to adjacent property owners as defined at OAR 345-020-0011(1)(f). Further, in accordance with OAR 345-020-0040, the Department distributed the NOI to the SAG, reviewing agencies, and tribal governments along with a memorandum requesting comments on the NOI. The Department also published notice of the NOI on November 28, 2018 in The Dalles Chronicle, a newspaper of general circulation in the area of the proposed facility. The NOI comment deadline was January 11, 2019. Pursuant to OAR 345-015-0140, the Department provided copies of each public comment to the applicant for consideration in the development of the ASC.

II.B. Project Order

On February 1, 2019, the Department issued a project order in accordance with ORS 469.330(3) and OAR 345-015-0160(1), which requires the Department to specify the state statutes, administrative rules, and local, state, and tribal permitting requirements applicable to the construction and operation of the proposed facility. The project order also outlines the ASC requirements from OAR 345-021-0010 that are relevant to the proposed facility.

II.C. Application for Site Certificate

The Department received the preliminary Application for Site Certificate (pASC) on July 5, 2019. The Department distributed the pASC to reviewing agencies and requested pASC review and comment by July 26, 2019. Additionally, the Department posted an announcement on its project website notifying the public that the pASC had been received.

Pursuant to OAR 345-015-0190(1), on July 31, 2019, the Department determined the pASC to be complete; requests for additional information were issued by the Department on July 31 and August 6, 2019. The applicant provided responses to the Department’s information requests on October 1st, 8th, and 22nd, and, provided supplemental responses to information requested for one mitigation option proposed in the draft Habitat Mitigation Plan on December 10th, 2019 (note that this information was not necessary in order for the Department to deem the ASC complete). After reviewing the applicant’s responses and revised ASC exhibits, the Department determined the pASC to be complete on October 31, 2019. The applicant filed a complete ASC on November 4, 2019.

Department received the complete ASC on November 5, 2019, with notice posted in The Dalles Chronicle on November 6, 2019. The Department held a public information meeting on the complete ASC on November 13, 2019 in Maupin, Oregon. Pursuant to OAR 345-015-0200, the Department distributed electronic copies of the complete ASC to reviewing agencies, along with a request for agency reports on the complete ASC by December 6, 2019. The Department received comments from six agencies, including reviewing agencies and a tribal government.

On October 25, 2019, the Council appointed Joe Allen, J.D., an administrative law judge with the Oregon Office of Administrative Hearings, as the hearing officer to conduct the public hearing on the draft proposed order and to conduct the contested case proceeding.

II.D. Council Review Process

The issuance of this DPO initiates a 39-day comment period. The Council’s appointed, third-party hearing officer will conduct a public hearing on the DPO starting at 6:00 P.M. on Tuesday, February 25, 2020 at the Maupin Civic Center in Maupin, Oregon—representing the geographic area affected by the proposed facility. In addition to accepting written comments during the comment period, the hearing officer will also accept oral testimony at the public hearing. Following the close of the record of the public hearing and Council review of the DPO at a subsequent Council meeting, the Department will issue a Proposed Order, taking into consideration Council comments, any comments received “on the record of the public hearing” (i.e., oral testimony provided at the public hearing and written comments received by the Department from January 17, 2020 through February 25, 2020, as well as any responses to public comments by the applicant), and agency consultation.

Concurrent with the issuance of the Proposed Order, the Department will issue a notice of contested case and a public notice of the Proposed Order. Only those persons who comment in person or in writing on the record of the public hearing may request to participate as a party or limited party in the contested case proceeding. Additionally, to raise an issue in a contested case, the issue must be within Council jurisdiction, and the person must have raised the issue on the record of the public hearing with “sufficient specificity to afford the Council, the department, and the applicant an adequate opportunity to respond.” At the conclusion of the contested case proceeding, the hearing officer must issue a proposed contested case order.


1 Special Advisory Group the governing body of any local government within whose jurisdiction the facility is proposed to be located.

2 Pursuant to OAR 345-015-0190(5), an ASC is complete when the Department finds that the applicant has submitted information adequate for the Council to make findings or impose conditions on all applicable Council standards.

3 Reviewing agencies that commented on the complete ASC include Wasco County Planning Department, City of Maupin, ETWMO, STHO, DOGAMI, and ODFW.

4 See ORS 469.370(3)(d) and OAR 345-015-0014.

5 ORS 469.370(3)(i).
stating the hearing officer’s findings of fact, conclusions of law and recommended site certificate conditions on the issues in the contested case. The Council may adopt, modify or reject the hearing officer’s proposed contested case order.

Following the contested case proceeding, the Council will take action to either modify or approve the Proposed Order as the Final Order and issue a site certificate; or, may reject the Proposed Order, denying the Final Order and issuance of a site certificate based upon the standards adopted under ORS 469.501, and any additional state statutes, rules, or local government regulations or ordinances determined to be applicable to the proposed facility in the Project Order.13 The Council’s Final Order is subject to judicial review by the Oregon Supreme Court. Only a party to the contested case proceeding may request judicial review and the issues on appeal are limited to those raised by the parties to the contested case proceeding. A petition for judicial review must be filed with the Supreme Court within 60 days after the date of service of the Council’s final order or within 30 days after the date of the petition for rehearing is denied or deemed denied.14

III. DESCRIPTION OF THE PROPOSED FACILITY

The information presented in this section is based upon details provided in ASC Exhibits B and C. Section III.A, Proposed Facility Components describes proposed facility components and Section III.B, Proposed Facility Location described the proposed location, site boundary and micrositing corridor of the facility.

III.A. Proposed Facility Components

A proposed facility includes the energy facility together with any related or supporting facilities. Related or supporting facilities means any structure proposed by the applicant to be constructed or substantially modified in connection with the construction of an energy facility.15 As stated in ASC Exhibit B, the proposed facility includes a solar photovoltaic power generation facility and related and supporting facilities, with a nominal and average generating capacity of approximately 303 MW. The applicant seeks flexibility in final facility layout, number of equipment, and technology type selected, and has analyzed maximum impacts within a designated micrositing corridor to support Council review of requested flexibility, as further described in Section III.B., Proposed Facility Location, Site Boundary and Micrositing Corridor below. In addition, as described in Section III.C, the facility may be developed in a single build-out or in phases. Depending on customer demands or market conditions, the facility may be constructed in phases, requiring a partial site certificate transfer. Accordingly, the facility description below accounts for a total facility build-out and accounts for the worst-case scenario associated with project development.

Energy Facility

The proposed energy facility would be comprised of solar modules (mono- or poly-crystalline cells), tracker systems, posts (approx. 150,300 posts, steel or pile-type, assumed concrete foundations), and related electrical equipment (cabling; approx. 153 inverter/transformer stations; and, approx. 23 miles of above- and 4.2 miles of belowground 34.5 kV collection system – aboveground collector lines to be placed on single or double circuit monopole structures, 75 feet in height). The solar array will be enclosed with a chain-link perimeter fence, up to 8 feet in height, with two 16-foot-wide gates and one pedestrian, 4-foot-wide gate.16

The solar array will have shielded electrical cabling, as required by applicable code, to prevent electrical fires. The vegetation in the area under and around each solar module installation would be mowed annually and maintained sufficiently low, in accordance with the applicant’s draft Operational Fire Protection and Emergency Response Plan, to reduce fire-related fuels (see Attachment N of this order).

Routine operations and maintenance (O&M) activity would potentially include solar panel washing (approximately 1 million gallons of water per year), and infrequent repair and replacement of solar arrays and associated electrical equipment.

Related or Supporting Facilities

Proposed related or supporting facilities, as further described below, would include:

- 230 kV Transmission Line
- Collector Substation and Operations and Maintenance (O&M) Building/Onsite Sewage Disposal System
- Communication and Supervisory Control and Data Acquisition (SCADA) System
- Site Access, Service Roads, Perimeter Fencing, and Gates
- Temporary Staging Areas
- Battery Storage System, including 10,000-gallon water tank

Proposed 230 kV Transmission Line

The proposed 230 kV transmission line would extend approximately 11 miles from the proposed collector substation to Bonneville Power Administration’s (BPA) existing Maupin Substation, which interconnects to BPA’s 230 kV Big-Eddy to Redmond transmission line. The proposed 230 kV transmission line route extends northwest from the proposed collector substation for approximately 7.5 miles, and then for approximately 3.5 miles parallel Bakeoven Substation, which interconnects to BPA’s 230 kV Big-Eddy to Redmond transmission line. The proposed collector substation to Bonneville Power Administration’s (BPA) existing Maupin Substation, which interconnects to BPA’s 230 kV Big-Eddy to Redmond transmission line. The proposed collector substation to Bonneville Power Administration’s (BPA) existing Maupin Substation, which interconnects to BPA’s 230 kV Big-Eddy to Redmond transmission line. The proposed collector substation to Bonneville Power Administration’s (BPA) existing Maupin Substation, which interconnects to BPA’s 230 kV Big-Eddy to Redmond transmission line.
The proposed collector substation would combine and step up the voltage of energy generated by the proposed energy facility to the desired transmission voltage. The proposed collector substation would likely include two non-polyolychlorinated biphenyl oil-containing transformers (49,385 gallons total); circuit-breakers; power transformers(s); bus and insulators; disconnect switches; relaying, battery and charger; surge arresters; alternating current and direct current supplies; control enclosure; metering equipment; grounding; and associated control wiring. The proposed substation would be located within an approximately 3 acre graded area, and would be within a fenced area within the fenced solar array area, near the transmission line corridor, at the southern end of the proposed site boundary (see ASC Exhibit C, Figure C-2). The proposed collector substation will have sufficient spacing between equipment to prevent the spread of fire and will also be located on a gravel surface with no vegetation present to reduce any risk of fire from and to the proposed facility. All electrical equipment will meet National Electrical Code and Institute of Electrical and Electronics Engineers standards and will not pose a significant fire risk. The proposed operations and maintenance (O&M) building would be a single-story building, approximately 20 feet in height, within an approximately 5,000 square foot area, and would include office space, storage, bathroom, and breakroom facilities. Water would be supplied via an existing or newly constructed on-site permit exempt groundwater well (see ASC Exhibit O). The O&M building would also have an on-site, state permitted septic system, permitted by the Oregon Department of Environmental Quality, with a discharge capacity of up to 7,500 gallons. Electric power and telephone service would be provided via local service providers. A gravel parking and storage area would be located adjacent to the building. The proposed O&M building would be located near the solar array and would be located within the solar array perimeter fence. To reduce any risks of fire, the fenced areas around the O&M building will be graded, with no vegetation present. The O&M building will have basic firefighting equipment for use on site during maintenance activities, such as shovels, beaters, portable water for hand sprayers, fire extinguishers, and other equipment.

Proposed Communication and Supervisory Control and Data Acquisition System

A proposed communication and SCADA system would be installed to collect operating and performance data from the solar array. The SCADA system would allow for remote operation of the proposed facility from the O&M building and the applicant’s national control center in Portland, Oregon. Fiber optic cables for the SCADA system would be installed with the

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18 BSPAPPDoc#2  Exhibit B & Project Dees 2019-11-04, Section 2.7.
surveys and analysis encompassed the entirety of the micrositing corridor to inform the requirements of all Council standards and applicable rules and requirements based on siting of construction. In order for Council to authorize a micrositing corridor, allowing placement of construction of facility components may occur, subject to site certificate conditions. Micrositing OAR micrositing corridor to all facilities, all temporary laydown and staging areas and all corridors proposed by the applicant would occupy approximately 10,640 acre site boundary, entirely within private property. The proposed facility would be located within Wasco County, approximately 5 miles east of the City of Maupin and U.S. Highway 97; and, 5 miles south of State Highway 216. The regional location of the proposed facility site boundary and micrositing corridor are presented in Figure 1, Proposed Facility Location. The location of proposed facility components are presented in Figure 2, Proposed Facility Layout.

III.B. Proposed Facility Location, Site Boundary and Micrositing Corridor

The proposed facility would be located within southeastern Wasco County, approximately 5 miles east of the City of Maupin and U.S. Highway 97; and, 5 miles south of State Highway 216. The facility is proposed to occupy approximately 2,717 acres and be located within an approximately 10,640 acre site boundary, entirely within private property. “Site boundary” means the perimeter of the site of a proposed energy facility and its related or supporting facilities, all temporary laydown and staging areas and all corridors proposed by the applicant.20 Within the site boundary, the applicant seeks approval of an approximately 4,160 acre micrositing corridor to allow flexibility in the final location of facility components. As defined in OAR 345-001-0010, a “micrositing corridor” means a continuous area of land within which construction of facility components may occur, subject to site certificate conditions. Micrositing corridors are intended to allow some flexibility in specific component locations and design in response to site-specific conditions and engineering requirements to be determined prior to construction. In order for Council to authorize a micrositing corridor, allowing placement of facility components anywhere within the corridor, the Council must find that the applicant can comply with requirements of all Council standards and applicable rules and requirements based on siting of facility components anywhere within the micrositing corridor. As presented in Section IV, evaluation of Council Standards of this order, based on the applicant’s methodology, where surveys and analysis encompassed the entirety of the micrositing corridor to inform the evaluation of impacts under each Council standard, the Department recommends Council approve the micrositing corridor. While the applicant represents that the proposed facility would occupy up to 2,717 acres, in order to authorize a micrositing corridor, the Department recommends Council evaluate the permanent occupation of the proposed facility and potential impacts based on the size of the micrositing corridor, or 4,160 acres. The regional location of the proposed facility site boundary and micrositing corridor are presented in Figure 1, Proposed Facility Location. The location of proposed facility components are presented in Figure 2, Proposed Facility Layout.

III.C. Proposed Project Development and Phasing

The applicant may develop the facility in its entirety or may develop the facility in phases. If developed in phases, the phases would likely share related or supporting facilities like the 230 kV transmission line, access roads, the O&M building (including septic and possible groundwater wells), support infrastructure like the SCADA system, the collector substation, and possibly other related or supporting facilities described in this DPO. Phasing the facility may result staged construction and build-out under a single site certificate or it may result in staged construction and build-out under a partial site certificate transfer for a particular phase, which depends entirely on customer and market demands. The applicant anticipates that phased development may result in partial site certificate transfers for each phase and overlapping site boundaries for each phase, which involved shared facility agreements between or among the phases. If phased, and if customer or market demands require a partial site certificate transfer to accommodate the phasing, the sum of the all phases would not exceed the maximum build-out approved under this DPO. To the extent any additional related or support facility build-out was required to accommodate the phasing, the applicant would demonstrate that any minor modifications to the facility design would not trigger site certificate amendment under the “I coulds test” in OAR 345-027-0350. It is anticipated that any needed partial transfer could be accomplished via an amendment determination request under OAR 345-027-0657 and the transfer rule under OAR 345-027-0400.

The applicant anticipates that the proposed build-out or phasing may occur on the following schedule:

<table>
<thead>
<tr>
<th>Phase</th>
<th>Project size</th>
<th>Operational date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase 1</td>
<td>200 MW</td>
<td>2021</td>
</tr>
<tr>
<td>Phase 2</td>
<td>200 MW</td>
<td>2022</td>
</tr>
<tr>
<td>Phase 3</td>
<td>200 MW</td>
<td>2023-2024</td>
</tr>
</tbody>
</table>

This phasing schedule is not provided for ECSC approval but rather to document that future transfer requests may need approval to facilitate the full build-out of the facility.
Figure 1: Proposed Facility Location

Figure 2: Proposed Facility Layout
IV. EVALUATION OF COUNCIL STANDARDS

As discussed above, ORS 469.320 requires a site certificate from the Energy Facility Siting Council (EFSC or Council) before construction of a "facility." ORS 469.300(14) defines "facility" as an "energy facility together with any related or supporting facilities." The proposed facility qualifies as an "energy facility" under the definition in ORS 469.300(11)(a)(D)(6).

To issue a site certificate for a proposed facility, the Council must determine that "the facility complies with the applicable standards adopted by the Council pursuant to ORS 469.501 or the overall public benefits of the facility outweigh any adverse effects on a resource or interest protected by the applicable standards that the facility does not meet." The Council must also determine that the proposed facility complies with all other applicable Oregon statutes and administrative rules, as identified in the project order, excluding requirements governing design or operational issues that do not relate to siting and excluding compliance with requirements of federally delegated programs. Nevertheless, the Council may consider these programs in the context of its own standards to ensure public health and safety and protection of the environment.

Under ORS 469.310, the Council is charged with ensuring that the "siting, construction and operation of energy facilities shall be accomplished in a manner consistent with protection of the public health and safety." ORS 469.401(2) further provides that the Council must include in the site certificate "conditions for the protection of the public health and safety," for the time for completion of construction, and to ensure compliance with the standards, statutes and rules described in ORS 469.501 and ORS 469.503. The Council implements this statutory framework and ensures the protection of public health and safety by adopting findings of fact, conclusions of law, and conditions of approval concerning the proposed facility’s compliance with the Council’s Standards for Siting Facilities at OAR 345, Divisions 22, 24, 26, and 27.

This DPO includes the Department’s initial analysis of whether the proposed facility meets each applicable Council Standard (with mitigation and subject to compliance with recommended conditions, as applicable), based on the information in the ASC. Following the 39-day comment period on the DPO, public hearing on February 25, 2020, and Council’s review of the DPO and comments received at a subsequent Council meeting, likely in March 2020, the Proposed Order would be issued presenting the Department’s evaluation of the comments and additional evidence, if received on the record of the DPO.

Findings of Fact

ORS 469.022-0000 provides the Council’s General Standard of Review and requires the Council to find that a preponderance of evidence on the record supports the conclusion that a proposed facility would comply with the requirements of EFSC statutes and the siting standards adopted by the Council and that a proposed facility would comply with all other Oregon statutes and administrative rules applicable to the issuance of a site certificate for the facility.

ORS 469.022-0000(2) and (3) apply to proposed facilities where an applicant has shown that the proposed facility cannot meet an applicable Council standard. Therefore, OAR 469.022-0000(5) and (6) do not apply to this review.

IV.A. General Standard of Review: OAR 345.022-0000

(1) To issue a site certificate for a proposed facility or to amend a site certificate, the Council shall determine that the preponderance of evidence on the record supports the following conclusions:

(a) The facility complies with the requirements of the Oregon Energy Facility Siting statutes, ORS 469.300 to ORS 469.570 and 469.590 to 469.619, and the standards adopted by the Council pursuant to ORS 469.501 or the overall public benefits of the facility outweigh the damage to the resources protected by the standards the facility does not meet as described in section (2);

(b) Except as provided in OAR 345.022-0030 for land use compliance and except for those statutes and rules for which the decision on compliance has been delegated by the federal government to a state agency other than the Council, the facility complies with all other Oregon statutes and administrative rules identified in the project order, as amended, as applicable to the issuance of a site certificate for the proposed facility. If the Council finds that applicable Oregon statutes and rules, other than those involving federally delegated programs, would impose conflicting requirements, the Council shall resolve the conflict consistent with the public interest.

In resolving the conflict, the Council cannot waive any applicable state statute.

(4) In making determinations regarding compliance with statutes, rules and ordinances normally administered by other agencies or compliance with requirement of the Council, if other agencies have special expertise, the Department of Energy shall consult with such other agencies during the notice of intent, site certificate application and site certificate amendment processes. Nothing in these rules is intended to interfere with the state’s implementation of programs delegated to it by the federal government.
The requirements of OAR 345-022-0000 are discussed in the sections that follow. The Department consulted with other state agencies, and the Wasco County Board of Commissioners during review of the ASC to aid in the evaluation of whether the proposed facility would satisfy the requirements of applicable statutes, rules and ordinances otherwise administered by other agencies. Additionally, in many circumstances the Department relies upon these reviewing agencies' special expertise in evaluating compliance with the requirements of Council standards.

OAR 345-022-0000(2) and (3) apply to ASCs where an applicant has shown that the proposed facility cannot meet Council standards, or has shown that there is no reasonable way to meet the Council standards through mitigation or avoidance of the damage to protected resources; and, for those instances, establish criteria for the Council to evaluate in making a balancing determination. The applicant does not assert that the proposed facility would not meet an applicable Council standard. Therefore, OAR 345-022-0000(2) and (3) do not apply to this review.

Certificate Expiration (OAR 345-027-0013)

ORS 469.370(12) requires the Council to "specify in the site certificate the date by which construction of the facility must begin." ORS 469.401(2) requires that the site certificate contain a condition "for the time for completion of construction." Under OAR 345-025-0006(4), the certificate holder must begin construction on the facility no later than the construction beginning date specified by Council in the site certificate. "Construction" is defined in ORS 469.300(6) and OAR 345-010-0010(12) to mean "work performed on a site, excluding surveying, exploration or other activities to define or characterize the site, the cost of which exceeds $250,000."

In ASC Exhibit B, the applicant requests Council consideration of a construction commencement deadline 5 years from issuance of the site certificate (or, 1 year after the construction commencement deadline). The applicant represents that the proposed facility would be constructed in phases and a construction completion deadline 6 years from issuance of the site certificate (or, 1 year after the construction commencement deadline). The proposed facility were to be constructed as

a. Construction of the facility or any phase of the facility may be constructed in phases and has not represented that the entirety of the proposed facility could feasibly be constructed in 1 year if construction commencement (of the facility) were to occur on year 5, the Department recommends Council impose construction commencement deadlines that align with the applicant’s request and representations of construction schedule (i.e. a 3 and 5 year commencement deadline based on phase).

Recommended General Standard Condition 1: The certificate holder shall begin and complete construction of the facility or any phase of the facility by the dates specified in the site certificate.

a. Construction of the facility or any phase of the facility shall commence within three years after the date of Council action. Within 7 days of construction commencement, the certificate holder shall provide the Department written verification that it has met the construction commencement deadline.

b. Construction of the last phase of the facility, if constructed in phases, shall commence within five years after the date of Council action. Within 7 days of construction commencement, the certificate holder shall provide the Department written verification that it has met the construction commencement deadline.

c. Construction of all facility components shall be completed within six years after the date of Council action. Within 7 days of construction commencement.
Mandatory and Site-Specific Conditions in Site Certificates [OAR 345-025-0006 and OAR 345-025-0010]

OAR 345-025-0006 lists certain mandatory conditions that the Council must adopt in every site certificate. Mandatory conditions OAR 345-025-0006(7) through (9) and (16) are discussed and applied in Section IV.G., Retirement and Financial Assurance, of this order as they relate to the restoration of the site, Council approval of a retirement plan, and bonding requirements of the applicant. Mandatory conditions OAR 345-025-0006(12) through (14) are discussed and applied in Section IV.C, Structural Standard, because they are associated with the design, construction and the operation of the proposed facility to avoid dangers of seismic hazards, coordination with and notifications to the Department of Geology and Mineral Industries. In addition, pursuant to OAR 345-025-0006(10), the Council shall include as conditions in the site certificate all representations in the ASC and supporting record the Council deems to be binding commitments made by the applicant, as necessary to avoid or minimize a potential impact.

Mandatory conditions that are not otherwise addressed in the evaluation of compliance with specific standards are discussed below, in the context of the Council’s General Standard of Review.

The following are applicable mandatory conditions required pursuant to OAR 345-025-0006:

**Recommended General Standard Condition 2:** The certificate holder shall submit a legal description of the site to the Oregon Department of Energy within 90 days after beginning operation of the facility or any phase of the facility. The legal description required by this rule means a description of metes and bounds or a description of the site by reference to a map and geographic data that clearly and specifically identify the outer boundaries that contain all parts of the facility.

**Recommended General Standard Condition 3:** The certificate holder shall design, construct, operate, and retire the facility or any phase of the facility:

a. Substantially as described in the site certificate;

b. In compliance with the requirements of ORS Chapter 469, applicable Council rules, and applicable state and local laws, rules and ordinances in effect at the time the site certificate is issued; and

c. In compliance with all applicable permit requirements of other state agencies.

**Recommended General Standard Condition 4:** Except as necessary for the initial survey or as otherwise allowed for wind energy facilities, transmission lines or pipelines under this section, the certificate holder shall not begin construction, as defined in OAR 345-001-0010, or create a clearing on any part of the site until the certificate holder has construction rights on all parts of the site. For the purpose of this rule, “construction rights” means the legal right to engage in construction activities. For the transmission line associated with the energy facility if the certificate holder does not have construction rights on all parts of the site, the certificate holder may nevertheless begin construction, as defined in OAR 345-001-0010; or create a clearing on a part of the site if the certificate holder has construction rights on that part of the site and the certificate holder would construct and operate part of the facility on that part of the site even if a change in the planned route of a transmission line occurs during the certificate holder’s negotiations to acquire construction rights on another part of the site.

**Recommended General Standard Condition 5:** If the certificate holder becomes aware of a significant environmental change or impact attributable to the facility or any phase of the facility, the certificate holder shall, as soon as possible, submit a written report to the Department describing the impact on the facility and any affected site certificate conditions.

**Recommended General Standard Condition 6:** Upon completion of construction, the certificate holder shall restore vegetation to the extent practicable and shall landscape all or ownership of the site certificate holder, the certificate holder shall inform the Department of the proposed new owners. The requirements of OAR 345-027-0100 apply to any transfer of ownership that requires a transfer of the site certificate.

**Recommended General Standard Condition 7:** Before any transfer of ownership of the facility, any phase of the facility, or ownership of the site certificate holder, the certificate holder shall inform the Department of the proposed new owners. The requirements of OAR 345-027-0100 apply to any transfer of ownership that requires a transfer of the site certificate.

In addition to mandatory conditions imposed on all facilities, the Council rules also include “site specific” conditions at OAR 345-025-0010 that the Council may include in the site certificate to address issues specific to certain facility types or proposed features of facilities.27

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27 Site-Specific Conditions at OAR 345-025-0010(2)(i), (ii), and (ii)(j) do not apply to the proposed facility based on facility energy source/type (solar photovoltaics power generation facility with related and supporting facilities including a proposed 230 kV transmission line).
Because the proposed facility includes a 230 kV transmission line, the Department recommends the Council adopt the following site specific conditions:

**Recommended General Standard Condition 8:** The certificate holder shall:

a. Design, construct and operate the transmission line in accordance with the requirements of the National Electrical Safety Code as approved by the American National Standards Institute; and

b. The certificate holder shall develop and implement a program that provides reasonable assurance that all fences, gates, cattle guards, trailers, or other objects or structures of a permanent nature that could become inadvertently charged with electricity are grounded or bonded throughout the life of the line.

**Recommended General Standard Condition 9:** The certificate holder is authorized to construct a 230 kV transmission line anywhere within the approved corridor, subject to the conditions of the site certificate. The approved corridor extends approximately 11 miles from the microtunnel that contains the solar arrays and other related or supporting facilities, along the transmission corridor route, to the interconnection point at the BPA Maupin Substation, as further described in ASC Exhibit B and C and as presented in Figure 1 of the site certificate.

**Construction and Operation Rules for Facilities [OAR Chapter 345, Division 26]**

The certificate holder is authorized to construct, operate and retire the proposed facility in accordance with all applicable rules adopted by the Council in OAR Chapter 345, Division 26. The certificate holder shall, at a minimum, submit to the Department a compliance plan and a schedule of significant milestones for overall construction and operation. The certificate holder shall construct, design, and operate the proposed facility in a manner that protects public health and safety and has demonstrated the ability to restore the site to a useful, non-hazardous condition. The Department recommends the Council adopt General Standard Condition 10, as presented below, to support the Department’s review of ongoing site certificate compliance, in accordance with OAR Chapter 345, Division 26.

**Recommended General Standard Condition 10:** At least 90 days prior to beginning construction of the facility or any phase of the facility (unless otherwise agreed to by the Department), the certificate holder shall submit to the Department a compliance plan documenting and demonstrating actions completed or to be completed to satisfy the requirements of all site certificate terms and conditions and applicable statutes and rules.

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20. Applicable rule requirements established in OAR Chapter 345, Division 26 include OAR 345-025-0005 to OAR 345-026-0176.

**Construction and Operation Rules for Facilities [OAR Chapter 345, Division 26]**

The plan shall be provided to the Department for review and compliance determination for each requirement. The Department may request additional information or evaluation deemed necessary to demonstrate compliance.

**[PRE-GS-01, OAR 345-026-0048]**

**Conclusions of Law**

Based on the foregoing recommended findings of fact, conclusions of law, and subject to recommended conditions, the Department recommends Council find that the proposed facility would satisfy the requirements of OAR 345-022-0000.

**IV.B. Organizational Expertise: OAR 345-022-0010**

(1) To issue a site certificate, the Council must find that the applicant has the organizational expertise to construct, operate and retire the proposed facility in compliance with Council standards and conditions of the site certificate. To conclude that the applicant has this expertise, the Council must find that the applicant has demonstrated the ability to design, construct and operate the proposed facility in compliance with site certificate conditions and in a manner that protects public health and safety and has demonstrated the ability to restore the site to a useful, non-hazardous condition. The Council may consider the applicant’s experience, the applicant’s access to technical expertise and the applicant’s past performance in constructing, operating and retiring other facilities, including, but not limited to, the number and severity of regulatory citations issued to the applicant.

(2) The Council may base its findings under section (1) on a rebuttable presumption that an applicant has organizational, managerial and technical expertise, if the applicant has an ISO 9000 or ISO 14000 certified program and proposes to design, construct and operate the facility according to that program.

(3) If the applicant does not itself obtain a state or local government permit or approval for which the Council would ordinarily determine compliance but instead relies on a permit or approval issued to a third party, the Council, to issue a site certificate, must find that the third party has, or has a reasonable likelihood of obtaining, the necessary permit or approval, and that the applicant has, or has a reasonable likelihood of entering into, a contractual or other arrangement with the third party for access to the resource or service required by that permit or approval.

(4) If the applicant relies on a permit or approval issued to a third party and the third party does not have the necessary permit or approval at the time the Council issues the site certificate, the Council may issue the site certificate subject to the condition that the applicant shall commence construction or operation as appropriate until the third party has obtained the necessary permit or approval and the applicant has a contract or...
other arrangement for access to the resource or service secured by that permit or approval.

Findings of Fact

Subsections (1) and (2) of the Council’s Organizational Expertise standard require that the applicant demonstrate its ability to design, construct and operate the proposed facility in compliance with Council standards and all site certificate conditions, and in a manner that protects public health and safety, as well as its ability to restore the site to a useful, non-hazardous condition. The Council may consider the applicant’s experience and past performance in constructing, operating and retiring other facilities in determining compliance with the Council’s Organizational Expertise standard. Subsections (3) and (4) address third party permits.

Construction, Operation and Retirement of the Proposed Facility

The Council may consider an applicant’s past performance, including but not limited to the quantity or severity of any regulatory citations in the construction or operation of a facility, type of equipment, or process similar to the facility, in evaluating whether the applicant has demonstrated an ability to design, construct and operate a facility in compliance with Council standards and site certificate conditions. To evaluate whether the applicant has demonstrated an ability to comply with Council standards and site certificate conditions, the Department presents an evaluation of the applicant’s relevant experience with constructing and operating similar systems and considers whether any regulatory citations have been received for its facilities.

Bakeoven Solar, LLC is a project-specific LLC and therefore relies upon the organizational expertise and experience of its parent company, Avangrid Renewables, LLC, to demonstrate compliance with the Council’s Organizational Expertise standard, as presented in ASC Exhibit D. Exhibit D states that Avangrid has experience in the design, construction, and operation of wind energy facilities, solar energy facilities, natural gas fired generation, and co-generation facilities, substations, and low- and high-voltage electrical lines. Moreover, Avangrid owns and operates more than 6,000 MW of utility-scale renewable energy production, with more than 1,483 MW of utility-scale wind and solar generation within Oregon. While the applicant represents that it has not constructed and operated battery storage systems specifically, Avangrid is currently in the permitting phase for four battery storage projects within the United States, and considers the design and operation of a battery to be fundamentally similar to its other facilities and components.

The applicant’s parent company is also the certificate holder parent company for six EFSC jurisdictional energy facilities including Leaning Juniper IA Wind Power Facility, Leaning Juniper IIB Wind Power Facility, Klondike III Wind Project, Montague Wind Power Facility, Golden Hills IIB Wind Farm, and Klamath Cogeneration Project, some of which are operational, were recently constructed (2016-2019) or are planned to commence construction (2020-2021). The applicant affirms that neither the LLC or its parent company have received regulatory citations for any EFSC jurisdiction facility or related to constructing or operating any other facility, type of equipment, or process similar to the proposed facility within the United States.

Because the organizational expertise of Avangrid is relied upon to satisfy the requirements of the standard, the Department recommends Council impose the following condition to ensure that the applicant notifies the Department of any changes in the corporate structure of Avangrid Renewables:

Recommended Organizational Expertise Condition 1: During construction and operation of the facility or any phase of the facility, the certificate holder shall report to the Department, within 2 days, any change in the corporate structure of the parent company, Avangrid Renewables, LLC, that could impact the certificate holder’s access to the proposed resources or expertise of Avangrid Renewables, LLC.

The applicant has not selected an architect, engineer, prime contractor, or a major component vendor for the proposed facility; the applicant states in ASC Exhibit D that it has extensive experience selecting and working with experienced contractors during construction, operation and maintenance on similar facilities and components. The applicant refers to its experience selecting and working with experienced contractors during the construction and retirement of other facilities as well as its ability to design, construct and select contractors that have substantial experience in the design, construction, operation, and maintenance of similar facilities and components. The applicant refers to its experience selecting and working with experienced contractors during the construction of similar facilities and components. The applicant refers to its experience selecting and working with experienced contractors during the construction, operation, and maintenance of similar facilities and components. The applicant refers to its experience selecting and working with experienced contractors during the construction, operation, and retirement of the facility or any phase of the facility, the certificate holder shall notify the Department of any changes in the corporate structure of the parent company, Avangrid Renewables, LLC, that could impact the certificate holder’s access to the proposed resources or expertise of Avangrid Renewables, LLC.

The certificate holder shall select contractors that have substantial experience in the design, engineering and construction of similar facilities. The certificate holder shall report to the Department any changes of major contractors.

Recommended Organizational Expertise Condition 2: Before beginning construction of the facility or any phase of the facility, the certificate holder shall notify the Department of the identity and qualifications of the major design, engineering and construction contractor(s). The certificate holder shall select contractors that have substantial experience in the design, engineering and construction of similar facilities. The certificate holder shall report to the Department any changes of major contractors.

Recommended Organizational Expertise Condition 3: During design, construction, operation, and retirement of the facility or any phase of the facility, the certificate holder shall contractually require all contractors and subcontractors to comply with all applicable laws and regulations and with the terms and conditions of the certificate. The

60 OAR 345-021-0010(1)(d)(D)

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Wind Farm, and Klamath Cogeneration Project, some of which are operational, were recently
constructed (2016-2019) or are planned to commence construction (2020-2021). The applicant
affirms that neither the LLC or its parent company have received regulatory citations for any
EFSC jurisdiction facility or related to constructing or operating any other facility, type of
equipment, or process similar to the proposed facility within the United States.

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the standard, the Department recommends Council impose the following condition to ensure
that the applicant notifies the Department of any changes in the corporate structure of
Avangrid Renewables:

Recommended Organizational Expertise Condition 1: During construction and operation of
the facility or any phase of the facility, the certificate holder shall report to the Department,
within 2 days, any change in the corporate structure of the parent company, Avangrid
Renewables, LLC that could impact the certificate holder’s access to the proposed resources
or expertise of Avangrid Renewables, LLC.

The applicant has not selected an architect, engineer, prime contractor, or a major component
vendor for the proposed facility; the applicant states in ASC Exhibit D that it has extensive
experience selecting and working with experienced contractors during construction, operation
and maintenance on similar facilities and components. The applicant refers to its experience
utilizing specific selection criteria in the process of obtaining a qualified contractor to design
and construction the proposed facility. Because the ultimate responsibility for compliance
with the site certificate would lie with the certificate holder, but it is recognized that the
certificate holder would hire various contractors to design and build components of the
proposed facility, the Department recommends that Council adopt the following conditions
that clarify and confirm that the responsibility of compliance with the site certificate would be
with the certificate holder.

Recommended Organizational Expertise Condition 2: Before beginning construction of the
facility or any phase of the facility, the certificate holder shall notify the Department of the
identity and qualifications of the major design, engineering and construction contractor(s).
The certificate holder shall select contractors that have substantial experience in the design,
engineering and construction of similar facilities. The certificate holder shall report to the
Department any changes of major contractors.

Recommended Organizational Expertise Condition 3: During design, construction,
operation, and retirement of the facility or any phase of the facility, the certificate holder
shall contractually require all contractors and subcontractors to comply with all applicable
laws and regulations and with the terms and conditions of the site certificate. The

60 OAR 345-021-0010(1)(d)(D)
contractual obligation shall be required of each contractor and subcontractor prior to that
firm working on the facility. Such contractual provisions shall not operate to relieve the
certificate holder of responsibility under the site certificate.

[GEN-0E-02]

Recommended Organizational Expertise Condition 4: Any matter of non-compliance under
the site certificate is the responsibility of the certificate holder. Any notice of violation
issued under the site certificate will be issued to the certificate holder. Any civil penalties
under the site certificate will be levied on the certificate holder.

[GEN-0E-03]

Recommended Organizational Expertise Condition 5: In addition to the requirements of
OAR 345-026-0170, within 72 hours after discovery of incidents or circumstances that
violate the terms or conditions of the site certificate, the certificate holder must report the
conditions or circumstances to the Department.

[GEN-0E-04]

The applicant relies on the experience of its parent company in implementation of habitat
mitigation, as required under the Council’s Fish and Wildlife Habitat standard (OAR 345-022.
0060). In ASC Exhibit D, the applicant discusses its parent company’s experience designing
habitat mitigation projects for its other state and local jurisdictional energy facilities including
Klondike Wind III, Leaning Juniper Wind IA, Leaning Juniper IB, Montague Wind Power Facility,
Klamath Cogeneration, and Gala Solar. As evidence to support its documented experience in
habitat mitigation implementation, the applicant refers to annual reports submitted to the
Department documenting continued monitoring, reporting and adherence to agency
recommendations; and, a 2019 email from the Department’s compliance officer, Duane
Kildonk, confirming continued compliance with the requirements of EFSC Jurisdictional Habitat
Mitigation Plan requirements.

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Public Health and Safety

The proposed solar facility components and transmission line could result in health and safety
risks from risks to public providers of fire service during fire response events. The Department’s
evaluation of these risks is presented in Section IV.M., Public Services of this order.

Construction and operation of the proposed battery storage system could also result in public
health and safety risks during battery and battery waste transport; and, onsite handling and
storage of battery-related materials and waste. This is further discussed in Sections IV.M.,
Public Services and Section IV.N., Waste Minimization of this order.

In ASC Exhibit G, the applicant states that the proposed battery storage system would be
constructed and operated to comply with the requirements of the Department of
Transportation Pipeline and Hazardous Material Administration’s 49 Code of Federal
Regulations (CFR) 173.185. These regulations provide requirements for the prevention of
Based on the evidence in the record, and subject to compliance with the recommended conditions of approval, the Department recommends that the Council find that the applicant has adequately characterized the potential seismic, geological, and soil hazards of the site, and that the applicant can design, engineer and construct the facility to avoid dangers to human safety and the environment from these hazards. Pursuant to OAR 345-022-0020(2), the Council may issue a site certificate for a solar energy facility without making findings regarding compliance with the Structural Standard; however, the Council may apply the requirements of the standard to impose site certificate conditions.

The analysis area for review of geologic and soil stability, as evaluated under the Council’s Structural Standard, is the area within the site boundary. The analysis area for historic seismic and potentially active faults, as defined by the applicant, extends 50 miles from the proposed site boundary.

4.6 DOGAMI Consultation

Council rules at OAR Chapter 345 Division 21 require the applicant to consult with the Oregon Department of Geology and Mineral Industries (DOGAMI) on the appropriate methodology and scope of the seismic hazards, and geology and soil-related hazards assessments, and the appropriate site-specific geotechnical work to be completed to demonstrate compliance with the Council’s Structural Standard. The applicant consulted with DOGAMI and the Department during an in-person meeting on December 21, 2018. The applicant provides notes, as reviewed and concurred by DOGAMI staff, from the DOGAMI consultation in ASC Exhibit H Attachment H.

5. Potential Seismic, Geologic, and Soil Hazards within Analysis Area

OAR 345-022-0020(1)(a) requires the Council to find that the applicant has adequately characterized the seismic, geologic, and soil hazards of a proposed site.

Notes:
1) OAR 345-022-0020(1) does not apply to this ASC because the proposed facility would not meet the criteria for a special criteria facility as defined in ORS 469.371(1).
2) Site boundary, as defined in OAR 345-001-060(25), is the area within the perimeter of the facility, its related or supporting facilities, all temporary laydown and staging areas, and all miscoring corridors.
The applicant conducted a literature review, collected 1-foot contour data and conducted a limited geologic site reconnaissance of the area to inform the seismic characterization of the proposed site. Literature publications reviewed include topographic and geologic maps, aerial photographs, existing geological reports, and data provided by DOGAMI, Oregon Water Resources Department, United States Geological Survey (USGS), and the National Resource Conservation Survey. The site reconnaissance included a visual evaluation of existing exposures of soil and rock, classification of soils, and observation of typical slopes, as visible from roads, within the area of proposed facility components. Seismic hazards from earthquake events include seismic shaking or ground motion, fault rupture, liquefaction, seismically induced landslides, subsidence, which are described below.

The applicant identifies four sources of earthquakes and seismic activity in the region including crustal, intraplate, volcanic, and the Cascadia Subduction Zone. Based on the applicant’s literature review and 1-foot contour data collected at the site, there were no potentially active faults identified within the site boundary. However, based on a review of historic earthquakes, there were over 200 significant earthquakes within 50 miles of the proposed site boundary recorded since 1970. Significant earthquakes are those that caused Modified Mercalli Intensity (MMI) VIII shaking intensity or greater (i.e. shaking that is noticeable indoors but not be recognized as an earthquake). Of those, 3 significant historic earthquakes were recorded within the proposed site boundary (all recorded in 1976), with the closest most recent recorded significant earthquake occurring in 2011 (0.79 of a mile from the proposed site boundary) and 2010 (0.17 of a mile from the proposed site boundary).

Based on historical recorded earthquakes within 50 miles of the proposed site boundary, the applicant conducted a Ground Response Spectra Assessment to inform design requirements. The assessment assumed Site Class D amplification factors, a more conservative assumption than DOGAMI’s recommended Site Class C amplification assumption and more conservative given likely amplification factors of Site Class B at the site, but to be verified during the pre-construction assessment as further described below. Based on the assessment, the applicant represents that peak horizontal ground acceleration would be 0.187 acceleration from gravity (g) at bedrock and 0.270 g at ground surface. Then, for short period (0.2 second) and 1-second period ground motion, response acceleration is quantified at 0.644 g and 0.397 g, respectively.

This information is used to inform the design requirements for the proposed facility, as further described below.

The applicant relies upon DOGAMI’s Statewide Landslide Information Database for Oregon (SLIDO) Version 2 database and review of its 1-foot contour data collected at the proposed site to ascertain that no historic or active landslides are currently mapped at the proposed site. The applicant relies upon DOGAMI’s Oregon HazVu: Statewide Geohazards Viewer earthquake hazard layer, USGS’s Geologic Hazards Science Center, and its 1-foot contour data collected at the site to ascertain that no currently active faults are mapped at the proposed site. In ASC
In ASC Exhibit H, the applicant describes that solar foundation design would be based on the site-specific investigation report, and would address extreme loads, load cases for up-lift, shear failure, tension loads (for pile foundations), earthquake loads, subsurface loads, spring constants, verification procedures, and maximum allowable inclination moisture content and density, soil/bedrock bearing capacity, bedrock depth, settlement characteristics, structural backfill characteristics, soil improvement if required, and dynamic soil/bedrock properties including shear modulus and Poisson’s Ratio of the subgrade. The Council’s Mandatory Conditions at OAR 345-025-0006(12) – (14) provide structural related design requirements, which the Department recommends Council find sufficient to address the applicant’s ability to design the proposed facility to minimize public health and safety risk from a seismic or non-seismic related event, as represented below:

**Recommended Structural Standard Condition 2:** The certificate holder shall design, engineer and construct the facility to avoid dangers to human safety and the environment presented by seismic hazards affecting the site that are expected to result from maximum probable seismic events. As used in this rule “seismic hazard” includes ground shaking, ground failure, landslide, liquefaction triggering and consequences (including flow failure, settlement buoyancy, and lateral spreading), cyclic softening of clays and silts, fault rupture, directivity effects and soil-structure interaction.

**[GEN-SS-01; Mandatory Condition OAR 345-025-0006(12)]**

**Recommended Structural Standard Condition 3:** The certificate holder shall notify the Department, the State Building Codes Division and the Department of Geology and Mineral Industries promptly if shear zones, artesian aquifers, deformations or clastic dikes are found at or in the vicinity of the site. After the Department receives notice, the Council may require the certificate holder to consult with the Department of Geology and Mineral Industries and the Building Codes Division to propose and implement corrective or mitigation actions.

**[GEN-SS-02; Mandatory Condition OAR 345-025-0006(13)]**

**Recommended Structural Standard Condition 4:** The certificate holder shall notify the Department, the State Building Codes Division and the Department of Geology and Mineral Industries in the event that the Portland center is disabled. Avangrid also maintains a backup control center in Arizona to provide continuous service in the event that the Portland center is disabled.

**[GEN-SS-03; Mandatory Condition OAR 345-025-0006(14)]**
Similarly, BPA confirmed that it has system recovery plans for Maupin Substation and its associated transmission lines. Avangrid also operates 2,200 MW of northwest energy generation assets as a standalone Balancing Authority, and the proposed facility could be part of this network that serves regional energy markets. The applicant’s parent company, Avangrid, has the unique ability to manage and deliver energy through its Balancing Authority. In the event of disaster at the proposed facility site, Avangrid could re-dispatch resources from elsewhere in its Balancing Authority, such as the Klamath Cogeneration Facility in southern Oregon, to serve load in place of the proposed facility.

Future climatic conditions within the area of the proposed facility are projected to include greater annual average and summer temperatures, and more severe storm events and wildfires, among other changes. These specific changes are expected to increase stress to power lines in the region. The applicant asserts that reinforcing the local electric grid with solar power, battery storage, and a new transmission line would provide resilience to the overall energy grid in this part of Oregon. This reinforcement would be direct, by upgrading the system, which is anticipated to experience higher loads under rising temperatures and the related increases in power demand for summer cooling. It is also indirect, by supporting the delivery of power generated through a larger variety of sources, minimizing the potential reduction in hydro power’s role under future conditions. Based on the proposed system upgrade and additional reliability provided by the proposed facility, the Department recommends Council find that the design measures outlined in ASC Exhibit H would sufficiently address disaster resiliency and offset impacts of future climate change.

Conclusions of Law

Based on the foregoing analysis, and in compliance with OAR 345-023-0020(2), the Department recommends Council include the conditions listed above in the site certificate to address the Council’s Structural Standard.

IV.D. Soil Protection: OAR 345-022-0022

To issue a site certificate, the Council must find that the design, construction and operation of the facility, taking into account mitigation, are not likely to result in a significant adverse impact to soils including, but not limited to, erosion and chemical factors such as salt deposition from cooling towers, land application of liquid effluent, and chemical spills.

Findings of Fact

The Soil Protection standard requires the Council to find that, taking into account mitigation, the design, construction and operation of a proposed facility are not likely to result in a significant adverse impact to soils. The applicant’s assessment of potential soil impacts and compliance with the Soil Protection standard are included in ASC Exhibit I. Additional information related to the proposed facility’s potential effects to soils and proposed mitigation measures, as described by the applicant can be found in ASC Exhibit 6 (Materials Analysis) and ASC Exhibit K (Land Use).

The analysis area for the Soil Protection standard is the area within the site boundary. The applicant describes that construction activities would result in approximately 176 acres of temporary disturbance, and approximately 2,717 acres of permanent disturbance. As noted throughout this order, the Department recommends Council evaluate potential temporary and permanent impacts based on the entirety of the micrositing corridor, which would equate to approximately 4,160 acres of temporary and permanent disturbance.

Existing Soil Conditions and Land Use

Existing soil conditions within the analysis area are shown in ASC Exhibit I. The applicant classifies soil types using Natural Resources Conservation Service (NRCS) Soil Survey Geographic Database. As represented in Figure 3: Soil Types within Analysis Area, seven major soil types were identified within the analysis area, characterized as shallow to deep with high to very high permeability, with areas of fertile silt loams in loess deposits (i.e., wind-blown silt with lesser and variable amounts of sand and clay) on the flatter surface. Soils within the analysis area have a K factor (erosion factor that indicates the susceptibility of a soil to sheet and rill erosion by water) that ranges from 0.10 to 0.37, which could be considered moderately to highly erodible, and subject to sheet erosion and rill erosion by water. Land use within the analysis area is primarily composed of open rangeland, with a small portion used for cultivated agriculture (dry land wheat), as represented in Figure 4: High Value Farmland within Analysis Area. In Figure 4: High Value Farmland within Analysis Area, soils identified as “farmland of statewide significance,” represents arable soils and soils identified as “not prime farmland” represents non-arable soils.
ASC Exhibit I includes the applicant’s assessment of how the proposed facility may impact soils. Additional information related to the facility’s potential impacts to soils, as described by the applicant, and proposed mitigation measures can be found in ASC Exhibit G and Exhibit K.

Construction

As described by the applicant, during construction soils may be adversely impacted by a number of construction activities. These activities include: clearing and grubbing of vegetation in temporary construction areas, grading and widening of existing access roads, construction of new access roads, heavy equipment and haul truck traffic for the delivery of aggregates, concrete, water, drill rigs, and similar construction supplies, and fueling or maintenance of...
construction equipment or vehicles. These activities can lead to wind or water erosion, compaction, changes in drainage patterns, or spills or releases of chemicals or other liquid materials used during construction. To address these impacts, the applicant has proposed a number of management and mitigation measures. The mitigation measures and best management practices (BMPs) specific to soils are included in the applicants NPDES 1200-C permit application, specifically the Erosion and Sediment Control Plan (ESCP). The NPDES and ESCP are included in Exhibit I, Attachment I. NPDES 1200-C permits are federally-delegated from EPA to DEQ, and are therefore not included in or governed by the site certificate (draft ESCP is provided as Attachment D of this order). The NPDES 1200-C permit applies during construction, and is intended to regulate and manage stormwater. To ensure compliance with the NPDES 1200-C permit and the ESCP, the Department recommends that the Council adopt the following condition, requiring the applicant to implement all provisions of the NPDES 1200-C permit and the final ESCP, as approved by DEQ:

**Recommended Soil Protection Condition 1:**

a. Prior to construction of the facility or any phase of the facility, the certificate holder shall provide a copy to the Department of its DEQ issued NPDES 1200-C permit, including final Erosion Sediment Control Plan and associated drawings (as provided in Attachment D of the Final Order on the ASC). The ESCP, including the monitoring component, would be required to be implemented in accordance with DEQ requirements and Soil Protection Condition 1. In addition, the revegetation plan, required under Recommended General Standard of Review 6 also includes a monitoring program.

b. During construction of the facility or any phase of the facility, the certificate holder shall conduct all work in compliance with a final Erosion and Sediment Control Plan that is satisfactory to the Oregon Department of Environmental Quality as required under the National Pollutant Discharge Elimination System Construction Stormwater Discharge General Permit 1200-C.

c. A monitoring program is required as part of the ESCP and NPDES 1200-C permit, and the monitoring schedule is described in the ESCP submitted as Exhibit I, Attachment I. The ESCP, including the monitoring component, would be required to be implemented in accordance with DEQ requirements and Soil Protection Condition 1. In addition, the revegetation plan, required under Recommended General Standard of Review 6 also includes a monitoring program.

**General Operation**

As described by the applicant, potential impacts to soils from proposed facility operation could include accidental spills from oil- and other non-hazardous liquid containing equipment including solar facility inverters and transformers (approximately 37,332 gallons), substation transformers (approximately 49,385 gallons) and battery storage systems (approximately 1.4 million gallons of electrolyte solution). Based on the quantity of onsite oil-containing equipment proposed by the applicant, federal Spill Prevention Countermeasure and Control (SPCC) requirements pursuant to 40 CFR Part 112 would apply. Federal SPCC requirements include development and implementation of an SPCC plan, based on type and quantity of onsite materials, that would reduce the potential for accidental hazardous material spills to adversely impact soils, and would contain procedures to properly manage, contain, and reduce the significance of any spills that unintentionally occur during facility operations. As described in ASC Exhibit I, proposed facility operations would have minimal likelihood of impacting soils from potential spills of oil or other materials because all oil-containing equipment including solar facility inverters and transformers, and battery storage systems would be stored in completely contained, leak-proof modules on concrete pads, all of which would be inspected monthly by facility personnel. Nonetheless, because an SPCC is a federal requirement and the applicant refers to the implementation of an SPCC plan to demonstrate compliance with Council’s standard, the Department recommends that Council find that implementation of the SPCC as described above and in the ASC would reduce the potential for accidental hazardous material spills to adversely impact soils, and would contain procedures to properly manage, contain, and reduce the significance of any spills that unintentionally occur during facility operations. In order to ensure implementation of these measures, the Department recommends the Council adopt the following condition, requiring the applicant to develop and implement the SPCC in order to protect soils and mitigate potential adverse impacts to soils:

**Recommended Soil Protection Condition 2:** Prior to operation of the facility or any phase of the facility, the certificate holder shall provide a copy to the Department, of an operational Spill Prevention Control and Countermeasures (SPCC) plan, if required pursuant to 40 CFR 122.4041-0001 to 0240.

The applicant states that proposed facility operations would have no impact on soil erosion, as operations would be restricted to access roads and no ground disturbance would occur. In addition, as discussed in Section IV.A. General Standard of Review of this order, Recommended General Standard of Review Condition 6 requires the applicant to restore vegetation to the extent practicable and landscape all areas disturbed by construction. Restoration of temporarily impacted areas would further reduce the potential for erosion during facility operation. Subject to compliance with the recommended conditions above, the Department recommends that the Council find the design, construction, and operation of the proposed facility would not result in a significant adverse impact to soils.

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Conclusions of Law

Based on the foregoing findings of fact and conclusions, and subject to compliance with the recommended site certificate conditions, the Department recommends that the Council find that the proposed facility would comply with the Council's Soil Pollution standard.

IV. E. Land Use: OAR 345-022-0030

(1) To issue a site certificate, the Council must find that the proposed facility complies with the statewide planning goals adopted by the Land Conservation and Development Commission.

(2) The Council shall find that a proposed facility complies with section (1) if:

(a) The certificate holder elects to obtain local land use approvals under ORS 469.504(1)(a) and the Council finds that the facility has received local land use approval under the acknowledged comprehensive plan and land use regulations of the affected local government; or

(b) The applicant elects to obtain a Council determination under ORS 469.504(1)(b) and the Council determines that:

(A) The proposed facility complies with applicable substantive criteria as described in section (3) and the facility complies with any Land Conservation and Development Commission administrative rules and goals and any land use statutes directly applicable to the facility under ORS 197.646(3);

(B) For a proposed facility that does not comply with one or more of the applicable substantive criteria as described in section (3), the facility otherwise complies with the statewide planning goals or an exception to any applicable statewide planning goal is justified under section (4); or

(C) For a proposed facility that the Council decides, under sections (3) or (6), to evaluate against the statewide planning goals, the proposed facility complies with the applicable statewide planning goals or that an exception to any applicable statewide planning goal is justified under section (4).

(3) As used in this rule, the "applicable substantive criteria" are criteria from the affected local government's acknowledged comprehensive plan and land use ordinances that are required by the statewide planning goals and that are in effect on the date the applicant submits the application. If the special advisory group recommends applicable substantive criteria, as described under OAR 345-021-0050, the Council shall apply them. If the special advisory group does not recommend applicable substantive criteria, the Council shall decide either to make its own determination of the applicable substantive criteria and apply them or to evaluate the proposed facility against the statewide planning goals.

(a) The Council may find goal compliance for a proposed facility that does not otherwise comply with one or more statewide planning goals by taking an exception to the applicable goal. Notwithstanding the requirements of ORS 197.732, the statewide planning goal pertaining to the exception process or any rules of the Land Conservation and Development Commission pertaining to the exception process, the Council may take an exception to a goal if the Council finds:

(B) The land subject to the exception is irrevocably committed as described by the rules of the Land Conservation and Development Commission to uses not allowed by the applicable goal because existing adjacent uses and other relevant factors make uses allowed by the applicable goal impracticable; or

(c) The following standards are met:

(A) Reasons justify why the state policy embodied in the applicable goal should not apply;

(B) The significant environmental, economic, social and energy consequences anticipated as a result of the proposed facility have been identified and adverse impacts will be mitigated in accordance with rules of the Council applicable to the siting of the proposed facility; and

(C) The proposed facility is compatible with other adjacent uses or will be made compatible through measures designed to reduce adverse impacts.

Findings of Fact

The Land Use standard requires the Council to find that a proposed facility complies with the statewide planning goals adopted by the Land Conservation and Development Commission (LCDC). Under ORS 469.504(1)(b)(A), the Council may find compliance with statewide planning goals if the Council finds that a proposed facility "complies with applicable substantive criteria from the affected local government’s acknowledged comprehensive plan and land use regulations that are required by the statewide planning goals and in effect on the date the application is submitted." The preliminary ASC was received on July 5, 2019.

The analysis area for potential land use impacts, as defined in the project order, is the area within and extending ½ mile from the proposed site boundary.
The proposed facility would be located within Wasco County. Therefore, the governing body within Wasco County is the Special Advisory Group (SAG).\[^{21}\] Prior to receipt of the paSC, the Council appointed the Wasco County Board of Commissioners as a SAG.

**IV. I Local Applicable Substantive Criteria**

Under OAR 345-022-0030(2), the Council must apply the applicable substantive criteria recommended by the SAG, as long as those criteria are required by the statewide planning goals and in effect on the date the paSC is submitted. Applicable substantive criteria identified by the applicant in ASC Exhibit K are presented in Table 1: Wasco County Applicable Substantive Criteria.

### Table 1: Wasco County Applicable Substantive Criteria

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<tr>
<th>Section</th>
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<tr>
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<td>Authorization to Grant or Deny Conditional Uses, and Standards and Criteria Used</td>
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<tr>
<td>10.150</td>
<td>Siting Standards for Good Defensibility</td>
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<td>10.160</td>
<td>Defensible Space — Clearing and Maintaining a Fire Fuel Break</td>
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<td>10.170</td>
<td>Decreasing the Ignition Risks by Planning for a More Fire-Safe Structure</td>
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<td>19.030</td>
<td>Commercial Power Generating Facilities Review Process &amp; Approval Standards</td>
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<td>D2</td>
<td>Specific Standards, Solar Energy Facilities</td>
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<tr>
<td>20.040</td>
<td>Site Plan Approval Standards</td>
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\[^{21}\] Under ORS 465-480(3)(b), the Council must designate a Special Advisory Group the governing body of any local government whose jurisdiction the facility is proposed or proposed changes of a facility would be located.
applicant's evaluation of legal parcel status, and review by Wasco County Planning Department,  
the Department concurs with the determinations presented in Table 2: Legal Status of Parcels  
within Proposed Site Boundary (see Attachment E for legal parcel status table and confirmation  
obtained from Wasco County Planning Department). Therefore, the Department recommends  
the Council find that the proposed facility would satisfy this criteria.

Table 2: Legal Status of Parcels within Proposed Site Boundary

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<tr>
<th>Township, Range, Section, Tax Lot</th>
<th>Acct #</th>
<th>Acres within Site Boundary</th>
<th>Parcel Crosses Micrositing Corridor?</th>
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Note: All parcels are zoned A-1 (160).
The proposed facility would be located on EFU-zoned land in Wasco County and is evaluated as falling into two separate land use categories: Commercial Utility Facilities for the Purpose of Generating Power for Public Use by Sale (303 MW of solar photovoltaic energy generation equipment), including modules and accessory equipment like trackers, posts, cabling, inverters, transformers, collection systems, site access, private service roads, perimeter fencing, gates, temporary construction areas, and 100 MW of battery storage equipment); and, Utility Facilities Necessary for Public Service (proposed 11-mile 230 kV transmission line). An evaluation of the applicable substantive criteria for these uses within EFU-zoned land is presented below.

The following uses may be permitted on a legal parcel designated Exclusive Farm (A-1) Zone under ORS 215.283(1)(c)(B), a transmission line would be an associated transmission line. As provided in Section IV.E.2. Directly Applicable State Statutes, the proposed transmission line would be an associated transmission line. Notwithstanding the language in the county’s code, the conditional use requirements beyond those that are consistent with ORS 215.274 and the county cannot impose additional approval criteria. Therefore, the conditional use requirements WCLUDO Section 3.216 - Property Development Standards, Section 3.218 - Agricultural Protection, Chapter 10 - Fire Safety Standards, Chapter 20 - Site Plan Review would not apply to the proposed transmission line.

The following uses may be permitted on a legal parcel designated Exclusive Farm (A-1) Zone subject to Section 3.216 - Property Development Standards, Chapter 10 - Fire Safety Standards, Chapter 20 - Site Plan Review only if the request includes off-street parking, off-street loading or bicycle parking, as well as any other listed, referenced or applicable standards:

1. M. Commercial Power Generating Facility (Utility Facility for the Purpose of Generating Power) subject to Section 19.030. Except for wind facilities, transmission lines or pipelines, unless otherwise allowed by state regulations, the energy facility shall not preclude more than 12 acres from use as a commercial agricultural enterprise unless an exception is taken pursuant to OAR Chapter 660-004, or 20 acres from use as a commercial agricultural enterprise unless an exception is taken pursuant to OAR Chapter 660-004 and ORS 197.732. (Added 4/12)

WCLUDO Section 3.215(M) identifies “commercial power generating facility” as a commercial utility facility as a permitted conditional use in an EFU zone. The section limits commercial utility facilities from precluding more than 12 acres of high-value farmland or more than 20 acres of arable land from use as a commercial agricultural enterprise, unless an exception to the statewide policy embodied in Goal 3 is taken. The section also requires conditionally permitted uses to comply with WCLUDO Section 3.216 - Property Development Standards, Section 3.218 - Agricultural Protection, Chapter 10 - Fire Safety Standards, Chapter 20 - Site Plan Review.

The proposed solar facility, not including the proposed 230 kV transmission line, is evaluated under the “commercial power generating facility” land use category. The proposed solar facility would preclude more than 20 acres of arable land from use as a commercial agricultural enterprise. Therefore, because the proposed solar facility would preclude more than 20 acres of arable land from use as a commercial agricultural enterprise, the applicant would not comply with the WCLUDO Section 3.215(M) acreage limitation and a Goal 3 exception would be needed. In ASC Exhibit K, the applicant requests Council review and approval of a Goal 3 exception, as evaluated in Section IV.E.3., Goal 3 Exception below.

The evaluation of WCLUDO Section 3.216 - Property Development Standards, Section 3.218 - Agricultural Protection, Chapter 10 - Fire Safety Standards, Chapter 20 - Site Plan Review for the proposed solar facility is provided below.

Property development standards are designed to preserve and protect the character and integrity of agricultural lands, and minimize potential conflicts between agricultural operations and adjoining property owners.

A. Setbacks

1. Property Line
All dwellings (farm and non-farm) and accessory structures not in conjunction with farm use, shall comply with the following property line setback requirements:

1. If adjacent land is being used for perennial or annual crops, the setback shall be a minimum of 200 feet from the property line.
2. If adjacent land is being used for grazing, is zoned Exclusive Farm Use and has never been cultivated or is zoned F-1 or F-2, the setback shall be a minimum of 100 feet from the property line.
3. If the adjacent land is not in agricultural production and not designated Exclusive Farm Use, F-1 or F-2, the setback shall be a minimum 25 feet from the property line.
4. If any of the setbacks listed above conflict with the Sensitive Wildlife Habitat Overlay the following shall apply and no variance shall be required:
   a. The structure shall be set back a minimum of 25 feet from the road right of way or easement;
   b. The structure shall be located within 300 feet of the road right of way or easement pursuant Section 3.020(3)(c), Siting Standards; and
   c. As part of the application the applicant shall document how they are siting the structure(s) to minimize impacts to adjacent agricultural uses to the greatest extent practicable.

WCLUDO Section 3.216(A)(1)(a) establishes setbacks for dwellings and dwelling accessory structures, which because the proposed facility does not include these components, would not apply.

b. Farm structures shall be set back a minimum of 25 feet from the property line.

WCLUDO Section 3.216(A)(1)(b) establishes a minimum 25 foot setback from farm structures to the property line, which because the proposed facility does not include these structures, would not apply. In ASC Exhibit K, the applicant describes that if the proposed O&M building were to remain on the landscape following facility decommissioning, at the landowner’s request, it that it would comply with WCLUDO Section 3.216(b), which is a future, forecasted circumstance that is outside the scope of this review.

c. Additions, modifications or relocation of existing structures shall comply with all EFU setback standards. Any proposal that cannot meet these standards is subject to the following:
   (1) Dwellings: The proposed addition modification or relocation shall not result in nonconformity or greater nonconformity to property line setbacks or resource buffer requirements unless the addition will extend a structure further away from and perpendicular to the property line or resource. Any proposal that would place a relocated dwelling or extend an existing dwelling into or further toward the property line or resource, or expand an existing dwelling parallel into a setback or buffer shall also be subject to Chapters 6 & 7 - Variances and any other applicable review criteria. The provisions of Chapter 13 - Nonconforming Uses, Buildings and Lots are not applicable to replacement dwellings.
   (Added 4/12)
   (2) Farm & Non-Farm buildings and structures: The proposed addition, modification or relocation shall not result in nonconformity or greater nonconformity to property line setbacks or resource buffer requirements. If the building or structure currently conforms to all setback standards and the proposal would result in non-conformity a Chapter 6 or 7 variance will be required. If the building or structure currently does not conform to all setback standards and the proposal would increase the non-conformity it shall be subject to the applicable provisions of Chapter 13 - Nonconforming Uses, Buildings and Lots.

WCLUDO Section 3.216(A)(1)(c) establishes setback standards for additions, modifications, or relocation of existing dwellings, farm and non-farm buildings, which is not proposed by the applicant and therefore would not apply.

d. Property line setbacks do not apply to fences, signs, roads, or retaining walls less than four (4) feet in height.

Frost yard (road) property line setbacks do not apply to parking areas for farm related uses. However, parking areas for farm related uses must meet side and rear yard property line setbacks.

WCLUDO Section 3.216(A)(1)(d) provides that setbacks do not apply to fences, signs and roads, which while it applies to the proposed facility, does not require a finding of compliance by Council.

2. Waterways

a. Resource Buffers: All bottoms of foundations of permanent structures, or similar permanent fixtures shall be setback from the high water line or mark, along all streams, lakes, rivers, or wetlands.
   (1) A minimum distance of one hundred (100) feet when measured horizontally at a right angle for all water bodies designated as fish bearing by any federal, state or local inventory.
   (2) A minimum distance of fifty (50) feet when measured...
Council impose the following setback condition:

To ensure compliance with the applicable setback requirement, the Department recommends Council impose the following setback condition:

Recommended Land Use Condition 1: Prior to construction of the facility or any phase of the facility, the certificate holder shall demonstrate to the Department and Wasco County through mapping or other engineering drawing that the final facility layout, or layout of any final phase of the facility, complies with the following county setback requirements:

1. 25-foot minimum setback distance from permanent foundations (posts if in concrete, substation, O&M building) to all water bodies (seasonal or permanent) not identified on any federal, state or local inventory within the micrositing corridor include a portion of Salt Creek (which flows through Dead Dog Canyon) and 13 unnamed ephemeral or intermittent streams.

2. 50-foot minimum setback distance from structures (posts if in concrete, O&M building, substation) to the centerline of an irrigation ditch or pipeline, if the ditch or pipeline continues past the subject parcel to provide water to other nonparticipating property owners.

3. 30-foot vision clearance at access road driveways constructed by the facility that provide access to a public roadway.

Based on compliance with the above-recommended condition, the Department recommends Council find that the proposed facility would comply with WCLUDO Section 3.216(A)(3).

WCLUDO Section 3.216(A)(3) establishes a minimum 50-foot setback requirement from structures to the centerline of irrigation pipelines which continue past the subject parcel to provide water to other property owners. The applicant represents that there are a limited number of privately owned irrigation pipelines near or within the place of use irrigation water rights located within the proposed site boundary, but that setbacks would be adhered to through the applicant’s lease agreement terms. To further ensure that this setback is adhered to during final facility design, the Department recommends Council impose Land Use Condition 3.740 - Flood Hazard Overlay (FPO).

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Training regarding the vision clearance area is not located in or near the Wasco County Fairground.

B. Height: Except for those uses allowed by Section 4.070 - General Exception to Building Height Requirements, no building or structure shall exceed a height of 35 feet. Height is measured from average grade.

WCLUDO Section 3.216 establishes a restriction of 35 feet for the height of buildings or structures, with exceptions to the restriction identified in WCLUDO Section 4.070. In WCLUDO Section 4.070, "uses specified in Chapter 19 – Energy Facilities (meteorological towers, transmission towers and lines, and commercial, net-metering, and non-commercial/stand-alone power generating facilities)" are listed as exceptions to the building height requirements. The applicant describes that typical sign arrangements include one or two permanent free standing signs at the entrance to the O&M building. Freestanding signs shall be limited to twelve square feet in area and 8 feet in height measured from natural grade.

D. Signs

1. Permanent signs shall not project beyond the property line.
2. Signs shall not be illuminated or capable of movement.
3. Permanent signs shall describe only uses permitted and conducted on the property on which the sign is located.
4. Size and Height of Permanent Signs:
   (a) Freestanding signs shall be limited to twelve square feet in area and 8 feet in height measured from natural grade.
   (b) Signs on buildings are permitted in a ratio of one square foot of sign area to each linear foot of building frontage but in no event shall exceed 3 square feet and shall not project above the building.
5. Number of permanent signs:
   (a) Freestanding signs shall be limited to one at the entrance of the property. Up to one additional sign may be placed in each direction of vehicular traffic running parallel to the property if they are more than 750 feet from the entrance of the property.
   (b) Signs on buildings shall be limited to one per building and only allowed on buildings conducting the use being advertised.
6. Temporary signs such as signs advertising the sale or rental of the premise are permitted provided the sign is erected no closer than ten feet from the public road right-of-way.

WCLUDO Section 3.216(D) establishes sign requirements. The applicant describes that typical sign arrangements include one or two permanent free-standing signs located at or near the entrance to the facility site, or at the entrance to the O&M building. The applicant confirms that the applicant anticipates using temporary signs during construction to guide construction traffic. Temporary construction signs are addressed in WCLUDO Section 21.410.2.2 regarding.
E. Lighting: Outdoor lighting shall be sited, limited in intensity, shielded and hooded in a manner that prevents the lighting from projecting onto adjacent properties, roadways and waterways. Shielding and hooding materials shall be composed of non-reflective, opaque materials.

WCLUDO Section 3.216(E) establishes outdoor lighting requirements. In ASC Exhibit K, the applicant describes that the O&M building, substation, and battery storage facility would have outdoor lighting as needed for safe operation. Lighting at the substation and battery system would only operate when crews are on site for maintenance activities. Lighting at the O&M building would be motion-activate or on a timer to limit duration of illumination. The applicant affirms that outdoor lighting associated with final facility design would adhere to the county’s lighting requirements. To ensure compliance with WCLUDO Section 3.216(E), the Department recommends Council impose the following condition:

Recommended Land Use Condition 2: Prior to construction of the facility or any phase of the facility, the certificate holder shall demonstrate to the Department and Wasco County that all outdoor lighting at the O&M building and substation would be limited in intensity, shielded and hooded using non-reflective, opaque materials.

F. Parking: Off street parking shall be provided in accordance with Chapter 20.

WCLUDO Section 3.216(F) refers to off-street parking requirements as established in WCLUDO Chapter 20, which is evaluated in the following subsections.

G. New Driveways: All new driveways and increases or changes of use for existing driveways which access a public road shall obtain a Road Approach Permit from the appropriate jurisdiction, either the Wasco County Public Works Department or the Oregon Dept. of Transportation.
Based on the applicant’s representation, and compliance with the above-recommended
condition, the Department recommends Council find that the proposed facility would satisfy
the requirements of WCLUDO Section 3.218.

WCLUDO Chapter 5 Conditional Use Review
Section 5.020 Authorization to Grant or Deny Conditional Uses, and Standards and
Criteria Used
Conditional uses listed in this Ordinance shall be permitted, enlarged or otherwise
altered or denied upon authorization by Administrative Action in accordance with the
procedures set forth in Chapter 2 of this Ordinance. In judging whether or not a
conditional use proposal shall be approved or denied, the Administrative Authority shall
weigh the proposal’s appropriateness and desirability or the public convenience or
necessity to be served against any adverse conditions that would result from authorizing
the particular development at the location proposed, and to approve such use, shall find
that the following criteria are either met, can be met by observance of conditions, or are
not applicable.

A. The proposal is consistent with the goals and objectives of the Comprehensive Plan
and implementing Ordinances of the County.

WCLUDO Section 5.020(A) requires a conditionally permitted use to demonstrate consistency
with goals and objectives of the Wasco County Comprehensive Plan and Wasco County zoning
ordinance. Based on the evaluation presented in this section, the Department recommends
Council find that the proposed facility would satisfy WCLUDO Section 5.020(A).

B. Taking into account location, size, design and operational characteristics of the
proposed use, the proposal is compatible with the surrounding area and
development of abutting properties by outright permitted uses.

WCLUDO Section 5.020(B) requires proposed uses to demonstrate compatibility with the
surrounding area and development of abutting properties. Based on the analysis area, which
includes all area within and extending 0.5 mile from the proposed site boundary, the
surrounding area is characterized as rural agricultural, with agricultural uses comprised of
grazing and limited crop cultivation, and ranch homesteads. Potential impacts from the proposed
facility to the surrounding area include increased traffic on local roads (Bakeoven and Wilson
Roads) during construction, construction and operational noise, and visual impacts, all of which
are evaluated below.

The applicant describes that tractor and harvest related traffic associated with the limited areas
within the surrounding area used for cultivation primarily utilize the south side of Bakeoven
Fire and Police Protection: A Fire Prevention and Protection Plan (see Attachment N of this order) will be finalized with both the Juniper Flat Rural Fire Protection District and the newly formed Bakeoven Shaniko Rural Fire Protection District; a contractual agreement would be executed with Juniper Flat Rural Fire Protection District to provide 24-hour, 7-day per week fire response to the proposed facility site. The proposed facility would be equipped with fire protection equipment in accordance with the Oregon Fire Code and, as presented below in WCLUDO Chapter 5, would comply with Wasco County’s Fire Safety Standards.

On-site security would be provided by the applicant, and facility personnel would maintain ongoing communication with the Wasco County Sheriff’s Office, headquartered in The Dalles, Oregon. Operational facility components would be fenced; the proposed O&M building and substation would have locked gates.

Sewer and Water Facilities: The proposed facility would not require a connection to sewers or sewage treatment facilities.

Potential water sources to meet proposed facility water demand include the City of Maupin (under an existing municipal water right) and an existing or newly constructed well under a limited license to be issued by the Oregon Water Resources Department (OWRD). The applicant obtained confirmation from the City of Maupin that it could meet the facility’s construction-related water demand, while maintaining adequate service to the community.

Telephone and Electrical Service: Electricity and communication service for the O&M building would be provided by local service providers.

Solid Waste Disposal Facilities: The applicant coordinated with Wasco County Landfill to confirm sufficient capacity to accommodate solid waste disposal from the proposed facility.

Based on the impact assessment presented above, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 5.020(C).

D. The proposed use will not unduly impair traffic flow or safety in the area.

WCLUDO Section 5.020(D) requires a demonstration that a proposed use would not unduly impair traffic flow or safety in the area. Based on the ASC, the applicant evaluates potential traffic and transportation impacts within analysis areas extending up to 20 miles from the proposed site boundary (ASC Exhibit U Public Services). Based on this assessment, construction-related traffic would result in up to 750 average daily trips (ADT) (including worker vehicles, pick-up trucks, material delivery vehicles) on I-84 and Bakeoven Road, 364 ADTs on US 197, 92 ADTs on US 97 (north, part of alternate route), and 46 ADTs on US 97 (south, workforce-only). Construction-related traffic, based on increases in ADT on local roads, could result in short-term, traffic delays; however, the applicant proposes several BMPs designed to maintain safe and available roadways, and development of Construction Traffic Management Plans in consultation with state and local agencies for the facility or any phase of the facility. These measures have been incorporated and included in a condition recommended by the Department for Council’s inclusion in the site certificate (see recommended Public Services Condition 3).

WCLUDO Section 5.020(D) requires a demonstration that, during construction and operation, a proposed use would minimize noise, dust and odor to protect adjoining properties from such impacts. Wasco County assesses adjoining properties as those lands which share a common boundary line with the properties involved with the proposed use. For this analysis, the Department recommends Council evaluate adjoining properties as those land which share a common boundary line with the properties where facility components could be located, rather than limited to those which share a common boundary line with properties which the site boundary would be located. For the proposed facility, adjoining properties include three ranch homes within 0.5 mile.

Construction would generate noise and dust from operation of heavy equipment and haul trucks; construction activities would not result in odor impacts. As identified in ASC Exhibit X, construction activities may generate noise in excess of 10 dBA above existing ambient conditions and have the potential to cause temporary, short-term noise disturbances. In order to minimize potential noise impacts during proposed facility construction in accordance with WCLUDO Section 5.020(E), the Department recommends Council impose the following condition:

Recommended Land Use Condition 5: The certificate holder shall:

a. Prior to construction of the facility or any phase of the facility, provide written notification to residences located on land within 1,000 feet of the facility microstrip corridor, identifying the type, duration and frequency of construction activities.

b. During construction of the facility or any phase of the facility, implement the following noise reduction measures:

1. All construction equipment shall be equipped with noise-reduction devices such as

E. The effects of noise, dust and odor will be minimized during all phases of development and operation for the protection of adjoining properties.

WCLUDO Section 5.020(E) requires a demonstration that, during construction and operation, a proposed use would minimize noise, dust and odor to protect adjoining properties from such impacts. Wasco County assesses adjoining properties as those lands which share a common boundary line with the properties involved with the proposed use. For this analysis, the Department recommends Council evaluate adjoining properties as those land which share a common boundary line with the properties where facility components could be located, rather than limited to those which share a common boundary line with properties which the site boundary would be located. For the proposed facility, adjoining properties include three ranch homes within 0.5 mile.

Construction would generate noise and dust from operation of heavy equipment and haul trucks; construction activities would not result in odor impacts. As identified in ASC Exhibit X, construction activities may generate noise in excess of 10 dBA above existing ambient conditions and have the potential to cause temporary, short-term noise disturbances. In order to minimize potential noise impacts during proposed facility construction in accordance with WCLUDO Section 5.020(E), the Department recommends Council impose the following condition:

Recommended Land Use Condition 5: The certificate holder shall:

a. Prior to construction of the facility or any phase of the facility, provide written notification to residences located on land within 1,000 feet of the facility microstrip corridor, identifying the type, duration and frequency of construction activities.

b. During construction of the facility or any phase of the facility, implement the following noise reduction measures:

1. All construction equipment shall be equipped with noise-reduction devices such as
The Department recommends Council find that the proposed facility would satisfy WCLUDO Section 5.020(E).

Based on the above-reasoning and analysis, and compliance with the recommended conditions, the Department recommends Council find that the proposed facility would minimize noise, dust and odor to protect adjoining properties from such impacts and therefore would satisfy WCLUDO Section 5.020(E).

F. The proposed use will not significantly reduce or impair sensitive wildlife habitat, riparian vegetation along streambanks and will not subject areas to excessive soil erosion.

WCLUDO Section 5.020(F) requires a demonstration that the proposed use would not significantly reduce or impair sensitive wildlife habitat, riparian vegetation and would not create excessive soil erosion. The proposed facility would result in temporary and permanent wildlife impacts, all of which would be mitigated through implementation of a Revegetation Plan (see Attachment I of this order) and Habitat Mitigation Plan (see Attachment H of this order), both of which have been reviewed by the Department, ODWF and Wasco County Planning Department. The proposed facility would not be located on or within, or otherwise result in impacts to streams or riparian vegetation. Potential soil erosion impacts would be minimized through compliance with the NPDES 1200-C permit, which includes BMPs to minimize soil erosion impacts and implementation of a Revegetation Plan, which would ensure soil stabilizations. As presented throughout this order, the Department recommends Council impose conditions to ensure the applicant’s obtains necessary permits, and implements and adheres to BMPs and plan requirements. Based on compliance with recommended conditions, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 5.020(F).

G. The proposed use will not adversely affect the air, water, or land resource quality of the area.

WCLUDO Section 5.020(G) requires a demonstration that the proposed use would not adversely affect the air, water, or land resource quality of the area.

Construction-related activities would generate emissions, including dust, that would result in air quality impacts. However, any potential air quality impacts would be temporary and short-term in nature, and would dissipate rather quickly given the extent of the area within which construction activities could occur. If a temporary concrete batch plant is needed during construction, it would be permitted through DEQ’s General Permit, with established emission limits that the applicants’ third-party contractor would be required to satisfy. In addition, the applicant proposes to manage dust through daily application of water via water truck.

Operation of the proposed facility, as a renewable, non-fuel operated solar facility, would not result in air quality impacts, other than the negligible emissions generated from vehicle miles travelled to the facility site from the 5 to 10 potential permanent employees.

Construction-related activities would require approximately 77 million gallons per year per phase, which would be obtained from the City of Maupin or an existing or newly constructed water well. As provided in ASC Exhibit U and confirmed by the Department, the City of Maupin affirms that the construction water demand of the proposed facility could be met under the city’s existing water right. In addition, if water were to be provided by an existing or newly constructed water well, it would require a limited water use license from the Oregon Department of Water Resources, which would include an evaluation of water availability and would require adherence to specific conditions.

Construction-related activities could result in water quality impacts through stormwater run-off at the proposed site. The applicant proposes to manage and minimize potential stormwater run-off impacts through implementation of erosion control measures and BMPs in accordance with its NPDES 1200-C (see recommended Soil Protection Condition 1). Proposed facility operations include minimal ongoing activity and minimal use of materials, limiting any potential for water quality impacts.

Construction and operation of the proposed facility would result in impacts to EFU-zoned land, including the use and occupation of approximately 2,717 acres of agricultural lands by proposed solar facility components. The applicant describes that the proposed facility would not result in adverse impacts to agricultural land resources for several reasons. The potential impact to cultivated agriculture would be minimal – limited to approximately 323 acres within over 3,654 acres of arable land. Potential impacts to high-value farmland would be negligible as there are approximately 10.8 acres of high-value farmland within the proposed microturf corridor, which is not used for irrigated agriculture but for the creation of big game habitat for hunting. The proposed facility would result in approximately 10 square feet of impacts to high value farmland, which the Department recommends be considered negligible. The applicant commits to recording Farm-Forest Management Easements with each landowner with property within the proposed site boundary (see recommended Land Use Condition 4), as required per WCLUDO Section 3.218 and represents that the proposed facility would have a net benefit to...
Based on the information and analysis presented above, the Department recommends Council find that the proposed facility would not adversely affect the air, water or land resource quality of the area and therefore would satisfy WCLUDO Section 5.020(H).

H. The location and design of the site and structures for the proposed use will not significantly detract from the visual character of the area.

WCLUDO Section 5.020(H) requires a demonstration that the location and design of the site and structures of the proposed use would not significantly detract from the visual character of the area.

In ASC Exhibit K, “visual character” is described as the natural landscape, and evident modifications of the landscape, that have occurred through human development actions. The natural landscape of the area primarily consists of relatively flat and gently sloping terrain, with few hills or ridges that provide noticeable features of topographic relief. The canyon of Buck Hollow Creek, which flows generally to the northwest toward the Deschutes River, is a significant topographic feature in the northern part of the analysis area. Elsewhere, the plateau is dissected by small streams that typically flow to the west. Vegetation conditions within the area reflect the predominant use as open rangeland and some areas of cultivated land.

Modifications of the landscape within the area is limited to widely scattered clusters of ranch structures (homes and outbuildings), fencing, and roads. Paved roads, such as Bakeoven Road, are more noticeable modifications of the landscape where they are visible. Limited other infrastructure facilities are present, although electric transmission lines and communications towers are visible within some parts of the analysis area. A BPA substation is located on the south side of Bakeoven Road and west of the proposed solar arrays. The substation occupies approximately 20 acres and is intersected by three major, high-voltage transmission lines supported on lattice-steel structures. The substation and transmission lines are prominent features of the local visual setting.

Potential visibility of proposed facility components would modify the existing visual character of the area. The applicant describes that visibility of solar arrays would create non-natural geometric shapes or lines in locations where they are visible, particularly if seen from an elevated vantage point. The transmission line and overhead collection line structures would create recurring vertical elements and long linear features that would be noticeable changes on the landscape in some locations, although they would be similar and subordinate to existing infrastructure in other locations. Based on the existing visual character of the area which includes electrical infrastructure, and the fact that proposed facility visibility would be limited to observation of a shape or line from elevated vantage points, the Department agrees with the applicant’s conclusion and recommends Council find that the proposed facility would not significantly detract from the visual character of the area and therefore would satisfy WCLUDO Section 5.020(H).

The proposal will preserve areas of historic value, natural or cultural significance, and therefore would not be considered a resource of significance. The Department agrees.

Based upon the analysis presented in ASC Exhibit S, and the recommended condition of compliance, the Department agrees with the applicant’s conclusions and recommends Council find that the proposed facility would preserve areas of historic value, natural or cultural significance, or assets of particular interest to the community and therefore would satisfy WCLUDO Section 5.020(I).

J. The proposed use will not significantly increase the cost of accepted farm or forest practices on surrounding lands devoted to or available for farm and forest use. (Revised 1-92)

K. The proposed use will not force a significant change in accepted farm or forest practices on surrounding lands devoted to or available for farm or forest use. (Revised 1-92)

WCLUDO Section 5.020(J) and (K) require a demonstration that the proposed use would not force a significant change in accepted farm or forest practices or significantly increase the cost of accepted farm or forest practices on surrounding lands. Accepted farm practices on the 21 tax parcels located within 0.5-mile of the proposed site boundary include grazing, ranching and limited crop cultivation (primarily dryland wheat); the applicant confirms that there is no forest
use or forest practices within the land use analysis area.

3 Potential impacts to accepted farm practices from proposed facility construction and operation include temporary traffic impacts and increased risk of wildland fire. The applicant provides the following information to support a conclusion that potential impacts would be less than significant:

- Construction vehicles would use Bakeoven and Wilson Roads and would result in congestion and potential traffic flow and delay impacts. However, the primary segments of these roads that are used to support active cultivation (i.e. tractor and Harvey related traffic) – south side of Bakeoven Road - would not be used.
- In accordance with WCLUDO Section 3.218, Farm Forest Management Easements would be signed and recorded by each landowner with property within the site boundary.
- The proposed facility would not limit or impact current or future farm activities on the surrounding land and would not diminish the opportunity for neighboring parcels to expand, purchase, or lease any vacant land available for agricultural uses. In addition, the current agricultural uses within the site boundary would not be impacted and would continue during proposed facility construction and operation.
- The applicant would finalize a draft Operational Fire Protection and Emergency Response Plan (as provided in Attachment N of this order). Measures identified in the draft plan include design requirements for the proposed O&M building and substation, onsite fire protection equipment, worker training, financial agreements and ongoing coordination with local fire districts. In accordance with the Oregon Fire Code, and a Fire Plan will be developed for the Facility.

Based on review of the above referenced information, the Department agrees with the applicant’s conclusion and recommends that Council find that the proposed facility would not significantly change the accepted farming practices or significantly increase the cost of accepted farming practices within the surrounding area, and therefore would comply with WCLUDO Section 5.020(I) and (K).

WCLUDO Chapter 10 Fire Safety Standards

Section 10.020 Applicability of Fire Safety Standards

Applicability of Fire Safety Standards in Different Rural Zones: County Ordinances affect all rural zones (all zones outside an Urban Growth Boundary). All rural zones are subject to fire standards but the applicability of the specific standards varies by zone and by use type.

WCLUDO Section 10.020 establishes applicability of the county’s Fire Safety Standards, which includes commercial power generating facilities located in the resource zone outside of an Urban Growth Boundary. Therefore, WCLUDO Chapter 10 requirements would apply to the proposed facility.

Section 10.110 Siting Standards – Locating Structure for Good Defensibility

A. Does your building avoid slopes steeper than 40% (more than 40-foot elevation gain over 100 feet horizontal distance)?
B. Is your building set back from the top of slopes greater than 30% by at least 50 feet?
C. Is your building set back from the top of slopes greater than 30% but less than 40% by at least 30 feet?
D. Are there any structures or other extensions closer than 30 feet to top of slopes?

WCLUDO Section 10.110 establishes siting standards for buildings, which are defined in WCLUDO as any structure built for the support, shelter or enclosure of persons, animals or property. Based on this definition, the components of the proposed facility subject to the siting standards would include the proposed O&M building, substation and battery storage system.

The applicant affirms that all proposed buildings would be on land with less than a 40 percent slope, consistent with WCLUDO Section 10.110(A). The applicant also affirms that proposed buildings would be setback at least 50 feet from the top of any slopes greater than 30 percent, consistent with WCLUDO Section 10.110(B). Based on the applicant’s representation of facility design, and to ensure compliance with WCLUDO Section 10.110, the Department recommends Council impose the following condition:

Recommended Land Use Condition 6: Prior to construction of the facility or any phase of the facility, the certificate holder shall provide written confirmation to the Department, based on final design, engineering and geotechnical investigation, that the O&M building, substation and battery storage system would be located on land with less than a 40 percent slope and setback at a minimum of 50 feet from the top of slopes greater than 30 percent.

Based on the proposed facility design and siting, the Department agrees with the applicant’s conclusion and recommends that Council find that the proposed facility would comply with WCLUDO Section 10.110.

Section 10.120 Defensible Space – Clearing and Maintaining a Fire Fuel Break

A. Is your building surrounded by a 50-foot wide fire fuel break?
B. Is dense unmanaged vegetation beyond 50 feet from the outer edges of your buildings, including any extensions such as decks or eaves, kept to a MINIMUM? If located on steeper ground, have you created and maintained some clearings beyond the 50 feet fire fuel break?

WCLUDO Section 10.120(A) and (B) establish a 50-foot minimum clearance distance and 50-foot
vegetation maintenance requirement for buildings. As described above, for the proposed facility, buildings would include the O&M building, collector substation and battery storage system. The applicant commits to maintaining a 50-foot fire fuel break around these buildings. The fenced areas around the O&M building, collector substation, and battery storage system would be graveled, with no vegetation present. Unmanaged vegetation beyond the 50-foot fire fuel break located around the O&M building, battery storage system, and substation would be minimal, as these facilities would be located in an area of low-growing shrubs and grass. As described in Attachment N (draft Operational Fire Protection and Emergency Response Plan) of this order, the applicant confirms that vegetation in the transmission corridor, and particularly around related infrastructure (e.g., poles), would be maintained pursuant to the Minimum Vegetation Clearance Distances defined under North American Electric Reliability Corporation and National Electric Code standards.

WCLUDO Section 10.120 wildfire fuel break and vegetation maintenance requirements are reflected in the draft Fire Prevention and Protection Plan provided as Attachment N of this order, and required to be finalized and implemented under recommended Land Use Condition 7. Based on the applicant’s representations and compliance with the recommended condition, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 10.120.

Section 10.130 Construction Standards for Dwellings and Structures – Decreasing The Ignition Risks by Planning for A More Fire-Safe Structure

A. Is your building designed, built, and maintained to include the following features and materials necessary to make the structure more fire resistant?

1. Roof Materials: Do you or will you have fire resistant roofing installed to the manufacturers specification and rated by Underwriter’s Laboratory as Class A, B, or its equivalent (includes but not limited to: slate, ceramic tile, composition shingles, and metal)? NOTE: To give your structure the best chance of surviving a wild fire, all structural projections such as balconies, decks and roof gables should be built with fire resistant materials equivalent to that specified in the uniform building code.

2. Fire resistant roofing will be utilized at the O&M building. No decks or horizontal extensions are planned for the O&M building. No trees will be planted or maintained adjacent to the building. This standard does not apply to the Facility structures including the substation, battery storage system, and solar arrays.

3. No other standards under this section apply.

WCLUDO Section 10.130 establishes roofing material requirements for dwellings and structures. The applicant identifies the O&M building as a structure and confirms that fire resistant roofing would be utilized. Based on this design representation, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 10.130.

WCLUDO Chapter 19 Standards for Non-Commercial Energy Facility, Commercial Energy Facilities & Related Uses

Section 19.030 Commercial Power Generating Facilities Review Process & Approval Standards

C. General Standards - The following standards apply to energy facilities as outlined in Section A above, in addition to meeting the Conditional Use Standards listed in Chapter 5:

1. Air Safety - All structures that are more than 200 feet above grade or, exceed airport imaginary surfaces as defined in DAR 738-070, shall comply with the air hazard rules of the Oregon Department of Aviation and/or Federal Aviation Administration. The applicant shall notify the Oregon Department of Aviation and the Federal Aviation Administration of the proposed facility and shall promptly notify the planning department of the responses from the Oregon Department of Aviation and/or Federal Aviation Administration.

Aerial Sprayers and operators who have requested to be notified will receive all notifications associated with the energy facility as required by Chapter 2, Development Approval Procedures.

WCLUDO Section 19.030(C)(1) establishes air safety standards for commercial power generating facilities, when structures greater than 200 feet in height, or that would exceed an airport imaginary surface, are proposed. As presented in ASC Exhibit C, proposed facility structures would include an overhead 230 kV transmission line, with structures up to 100 feet in height; overhead 34.5 kV collector transmission lines, with structures up to 75 feet in height; and other facility structures (solar panels, O&M building, collector substation, and battery storage systems) ranging from 12 to 20 feet in height. Based on the maximum height of proposed facility structures, no structures would be more than 200 feet in height, nor would any proposed facility structures exceed an airport imaginary surface. Therefore, based on the maximum height of proposed facility structures, the Department recommends Council find that WCLUDO Section 19.030(C)(1) would not apply.

2. Interference with Communications - The energy facility shall be designed, constructed and operated so as to avoid any material signal interference with communication systems such as, but not limited to, radio, telephone, television, satellite, microwave or emergency communication systems. Should any material interference occur, the permit holder must develop and implement a mitigation plan.
Council find that the proposed facility agrees with the maximum statistical noise levels modeled at 35 dBA, as presented in ASC Exhibit X Tables X allowable standard of 50 dBA at any noise degradation standard requires a demonstration that noise generated during proposed facility operation must not exceed the hourly L50 noise level at any noise-sensitive property to exceed 10 dBA above measured ambient conditions or, in this case, ambient conditions ranging from 17 to 31 dBA. Based upon the applicant’s noise analysis and noise contour maps provided in ASC Exhibit X, maximum increases in ambient noise levels from proposed facility operation would not exceed 9 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Therefore, the ambient noise degradation standard would not be exceeded at any noise sensitive property, even during maximum operational noise/rainy conditions. Additionally, the noise modeling results show that noise generated during proposed facility operation would not exceed the allowable standard of 50 dBA at any noise sensitive property within the analysis area, with maximum statistical noise levels modeled at 35 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Based on review of the applicant’s statistical noise modeling analysis, the Department agrees with the applicant’s conclusion of compliance with OAR 340-035-0035 and recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(2).

3. Noise - The energy facility shall comply with the noise regulations in OAR 340-035. The applicant may be required to submit a qualified expert’s analysis and written report.

WCLUDO Section 19.030(C)(3) requires that commercial power generating facilities demonstrate compliance with DEQ’s noise rules at OAR 340-035-0035 (i.e. ambient degradation standard and maximum allowable standard). As presented in Section IV.G.1, Noise Control Regulation of this order, the ambient noise degradation standard requires a demonstration that noise generated during proposed facility operation must not exceed the hourly L50 noise level at any noise-sensitive property to exceed 10 dBA above measured ambient conditions or, in this case, ambient conditions ranging from 17 to 31 dBA. Based upon the applicant’s noise analysis and noise contour maps provided in ASC Exhibit X, maximum increases in ambient noise levels from proposed facility operation would not exceed 9 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Therefore, the ambient noise degradation standard would not be exceeded at any noise sensitive property, even during maximum operational noise/rainy conditions. Additionally, the noise modeling results show that noise generated during proposed facility operation would not exceed the allowable standard of 50 dBA at any noise sensitive property within the analysis area, with maximum statistical noise levels modeled at 35 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Based on review of the applicant’s statistical noise modeling analysis, the Department agrees with the applicant’s conclusion of compliance with OAR 340-035-0035 and recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(3).

4. Visual Impact

a. Scenic Resources - To issue a conditional use permit for an energy facility, the county must find that the design, construction and operation of the facility, taking into account mitigation, are not likely to result in significant adverse impact to scenic resources or values identified as significant or important in the Wasco County Comprehensive Plan.

WCLUDO Section 19.030(C)(4)(a) requires the governing body to find that the commercial power generating facility would not be likely to result in significant adverse impacts to scenic resources or values identified as significant or important in the WCCP. As presented in ASC Exhibit R, the applicant identifies that the WCCP includes the following important or significant scenic resources within the analysis area:

- Deschutes River: Areas within the river canyon that can be seen from the Deschutes River or lands designated under the State Scenic Rivers Act.
- White River: Lands within the river canyon, or lands within approximately 4 miles of the river.
- Designated Scenic Routes: Specific segments along US 97, US 197, OR 216, OR 218.

Based on review of the applicant’s visual impact assessment, the existing visual character of the area within and near the identified important or significant resources, as further evaluated in Section IV.J of this order, either the proposed facility would not be visible from the identified resources or would result in a minimal change in visual context. Therefore, the Department agrees with the applicant’s conclusion and recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(4)(a).

b. Protected Areas - Except as provided in subsections (b) and (c) below, an energy facility shall not be located in the areas listed below:

1. National recreation and scenic areas, including but not limited to the Columbia River Gorge National Scenic Area.
2. Scenic waterways designated pursuant to ORS 390.826, wild or scenic rivers designated pursuant to 16 U.S.C. 1271 et seq., and those waterways and rivers listed as potentials for designation.
3. State parks and waysides as listed by the Oregon Department of Parks and Recreation.
4. State wildlife areas and management areas identified in OAR 635-008.
5. State natural heritage areas listed in the Oregon Register of Natural Heritage Areas pursuant to ORS 273.581.
6. Wilderness areas established pursuant to The Wilderness Act, 16 U.S.C. 1131 et seq. and areas recommended for designation as wilderness areas pursuant to 43 U.S.C. 1782; and
7. Except to Protected Areas - Except where the following uses are regulated by federal, state or local laws, including but not limited to the Columbia River Gorge National Scenic Area Act and implement land use ordinances, the following may be approved in a protected area identified in subsection b above if other alternative routes or sites
have been studied and been determined to have greater impacts

- An electrical transmission line;
- A natural gas pipeline; or
- An energy facility located outside a protected area that includes
  an electrical transmission line or natural gas or water pipeline as a
  related or supporting facility located within a protected area.

(b) Transmission Line & Pipeline Exception - The provisions of subsection b
above do not apply to electrical transmission lines or natural gas
pipelines routed within 500 feet of an existing utility right-of-way
containing at least one transmission line or one natural gas pipeline.

(c) Additional Visual Mitigation Impacts for All Facilities - The design,
construction and operation of the energy facility, taking into account
mitigation, are not likely to result in significant adverse impact to
scenic resources and values identified in subsection (b) above.

Methods to mitigate adverse visual impacts could include but are not
limited to:

(1) Building the energy facility near the edge of contiguous timber
  areas or using the natural topography to obscure the energy
  facility;

(2) Using materials and colors that blend with the background unless
  otherwise required by the Federal Aviation Administration or the
  Oregon Department of Aviation; and

(3) Retaining or planting vegetation to obscure views of the energy
  facility.

WCLUDO Section 19.030(C)(4)(b) prohibits siting of a commercial power generating facility
within designated protected areas, including national recreation and scenic areas, scenic
waterways, state parks and waysides, state wildlife and management areas, national and state
fish hatcheries, state natural heritage areas, and wilderness areas. As presented in ASC Exhibit P
(Protected Areas), the applicant has not proposed to locate any facility components within
designated protected areas. Therefore, based on avoidance of siting proposed facility
components within any designated protected area, the Department agrees with the applicant’s
conclusion and recommends Council find that the proposed facility would satisfy WCLUDO
Section 19.030(C)(4)(b).

5. Natural Resource/Wildlife Protection - Taking into account mitigation, siting,
design, construction and operation the energy facility will not cause significant
adverse impact to important or significant natural resources identified in the
Wasco County Comprehensive Plan, Wasco County Land Use and Development
Ordinance or by any jurisdictional wildlife agency resource management plan
adopted and in effect on the date the application is submitted. As appropriate, the
permit holder agrees to implement monitoring and mitigation actions that Wasco
County determines appropriate after consultation with the Oregon Department of
Fish and Wildlife, or other jurisdictional wildlife or natural resource agency.

Measures to reduce significant impacts may include, but are not limited to the
following:

a. Providing information pertaining to the energy facility’s potential impacts and
measures to avoid impacts on:
   (1) Wildlife (all potential species of reasonable concern);
   (2) Wild Habitat;
   (3) Endangered Plants; and
   (4) Wetlands & Other Water Resources.

b. Conducting biologically appropriate baseline surveys in the areas affected by
the proposed energy facility to determine natural resources present and
patterns of habitat use.

c. Selecting locations to reduce the likelihood of significant adverse impacts on
natural resources based on expert analysis of baseline data.

d. Utilizing turbine towers that are smooth steel structures that lack features that
would allow avian perching. Where horizontal surfaces cannot be avoided,
antiperching devices shall be installed where it is determined necessary to
reduce bird mortality.

e. Designing and installing all aboveground transmission line support structures
following the current suggested practices for avian protection on power lines
published by the Avian Power Line Interaction Committee.

f. Designing and installing all transmission line support structures designed so the
foundation area and supports avoid the creation of artificial habitat or shelter
for raptor prey.

g. Controlling weeds to avoid the creation of artificial habitat suitable for raptor
prey such as spreading gravel on turbine pad.

h. Avoiding construction activities near raptor nesting locations during sensitive
breeding periods and using appropriate no construction buffers around known
nest sites.

i. Locating transmission lines or associated transmission lines with the energy
facility to minimize potential impacts (e.g., 50 feet from the edge of the nearest
wetland or water body except where the line is required to cross the wetland or
water body; or separating transmission lines or associated transmission lines
with the energy facility from the nearest wetland or water body by topography
or substantial vegetation to the extent practical, except where the line is
required to cross the wetland or water body).

j. Locating transmission towers or associated transmission towers outside of
Class I or II streams unless:
   (1) Adjoining towers and conductors cannot safely and economically support
the line(s) that span the stream without an in-stream tower; and
   (2) The lines cannot be safely and economically placed under the water or
strata.

(3) Developing a plan for post-construction monitoring of the facility site
using appropriate survey protocols to measure the impact of the project
on identified natural resources in the area.
WCLUDO Section 19.030(C)(5) requires the governing body to find that the siting, design, construction and operation of a commercial power generating facility would not cause significant adverse impacts to important or significant natural resources identified in the WCCP, WCLUDO, or by any adopted jurisdictional wildlife agency management plan. Based on WCCP Goal 5 resources, WCLUDO and ODFW’s Mule Deer Management Plan, the proposed facility would be located within ODFW’s Category 2 habitat for big game winter range, but would not impact any significant or natural resources identified in the WCCP or WCLUDO.

WCLUDO Section 19.030(C)(5) then provides measures that could be implemented to reduce significant impacts, which the applicant addresses in ASC Exhibit K and therefore are evaluated below.

14. Potential wildlife impacts from proposed facility construction and operation are evaluated under the Council’s Fish and Wildlife Habitat standard (ASC Exhibit P). As presented in ASC Exhibit P, the applicant conducted special status wildlife and habitat surveys and a literature review to identify all potential species of reasonable concern with the potential to occur within or near the site boundary. “Species of reasonable concern” are defined as those species listed under federal or state Endangered Species Acts or listed on ODFW’s list of Species of Concern.

Based on this review, the only federally listed wildlife species with the potential to occur within or near the facility is the wolverine (Gulo gulo), which has only remote potential to occur as a transient (Exhibit Q), as the applicant verified that suitable habitat was not present within the analysis area. Two state sensitive species, Swainson’s hawk and Burrowing Owl, were observed during the applicant’s 2018 field surveys.

24. As provided in ASC Exhibit K and P, proposed facility impacts to wildlife species of reasonable concern and its habitat include permanent and temporary habitat loss, introduction of noxious weeds, potential nesting and breeding disturbance, electrocution, powerline collision, structure collision, vehicular collision, disturbance related to artificial lighting, disturbance to wintering big game, and entrapment within fenced areas. As provided in ASC Exhibit P and evaluated in Section IV.H. Fish and Wildlife Habitat of this order, the applicant utilized information about sensitive resources to select siting locations; and, proposes avoidance and minimization measures, compensatory mitigation, and implementation of a long term revegetation and noxious weed control plan, all of which were reviewed by the Department, ODFW and Wasco County Planning Department. Siting factors considered by the applicant in site selection included:

- Avoidance of fish bearing waters, vernal pools, and large wetland complexes to the extent practicable;
- Avoidance of ODFW Category 1 habitat;
- Avoidance of Comprehensive Plan designated EPD-7 Natural Areas and EPD-8 Sensitive Bird Overlay;
- To the extent feasible, siting on previously disturbed habitat, including dryland wheat and planted grassland, and outside sagebrush steps, which is an ODFW conservation strategy habitat.
- Siting away from identified nests of Swainson’s hawk, ferruginous hawk, and golden eagles such that these nests will not be disturbed by the facility;
- Avoidance of open water habitat and cliff habitat;
- Co-location of access roads and electrical lines with existing farm roads; and
- Minimization of the use overhead collection lines to the extent possible.

Based upon the above analysis supported by the evaluation provided in ASC Exhibit P, which is largely consistent with the requirements of Section 19.030(C)(5), and Department recommendations presented in Section IV.H. Fish and Wildlife Habitat of this order, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(5).

6. Protection of Historical and Cultural Resources - The applicant shall complete a cultural resources survey of areas where there will be temporary or permanent disturbance. During construction, cultural resources included in the Wasco County Comprehensive Plan shall be flagged and avoided in areas of potential temporary or permanent disturbance, and construction activities monitored to ensure all cultural resources in such areas are avoided, unless appropriate permits are obtained from the Oregon State Historic Preservation Office. Prior to construction on an Inadvertent Discovery Plan (IDP) shall be developed that must outline the procedures to be followed in the case previously undiscovered archeological, historical or cultural artifacts are encountered during construction or operation of the energy facility, in compliance with ORS 358.905-358.955 and any other applicable local, state and federal law.

WCLUDO Section 19.030(C)(5) requires that an applicant for a commercial power generating facility complete a cultural resource survey within areas of potential temporary and permanent disturbance and implement flagging and avoidance measures in areas with cultural resources identified in WCCP have been identified. WCLUDO Section 10.030(C)(6) also requires development and implementation of an Inadvertent Discovery Plan, consistent with ORS 358.905-358.955. As presented in ASC Exhibit S, the applicant’s consultant, PaleoWest, conducted intensive pedestrian surveys, in accordance with the Oregon State Historic Preservation Office’s (SHPO) 2016 field guidelines, within a 4,530 acre survey area (i.e. micrositing corridor), with 30 meter transect spacing. For the ASC, the applicant’s consultant also conducted a literature review including Oregon Archeological Records Remote Access (OARRA, 2018) system, NRHP, U.S. General Land Office, land patents, historical U.S. Geological Survey topographic maps, and ethnographic literature. Based on this review, there were no WCCP cultural resources identified; however, there were eighteen archeological sites, including two with historic built components, identified within the survey area.

The applicant commits to developing and finalizing an Inadvertent Discovery Plan, and provides (in ASC Exhibit S) a draft plan, as provided in Attachment L and recommended as a site certificate condition in recommended Cultural, Historic and Archeological Resources Condition 1.

Based on the applicant’s cultural resource survey, as provided in ASC Exhibit K, and the fact that...
no WCCP cultural resources were identified within the proposed site boundary, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(ii).

7. Fire Protection & Emergency Response - A fire protection and emergency response plan shall be developed and implemented in consultation with the applicable fire district or department and/or land management agency to minimize the risk of fire and respond appropriately to any fire or emergency that occurs onsite for all phases of the life of the facility. In developing the plan the applicant shall take into account, among other things, the terrain, dry nature of the region, address risks on a seasonal basis, and identify the locations of fire extinguishers, nearby hospitals, telephone numbers for emergency responders, and first aid techniques.

WCLUDO Section 19.030(C)(7) requires that an applicant for a commercial power generating facility develop and implement a Fire Protection and Emergency Response Plan, for all phases of construction and operation, in consultation with applicable fire districts and/or land management agency, and that the plan address, at a minimum, terrain, dry nature of the region, process for evaluating risks during seasonal variation, identify the location of fire extinguishers, nearby hospital, emergency responder telephone number and first aid techniques.

In ASC Exhibit K, the applicant represents that a construction and operational fire plan would be developed in consultation with the Oregon State Fire Marshal and Bakeoven Shanko Rangeland Fire Protection Association, and explains that the plans would adhere to WCLUDO Section 10.030(C)(7) requirements. The applicant also identifies, in ASC Exhibit U, that it would work with and have a contractual agreement with the Juniper Rural Flat Protection District, to provide 24-hour, 7-day a week emergency service to the proposed facility. Based on representations the ASC, the Department consolidated fire response and prevention measures into a draft Fire Prevention and Response Plan for proposed facility operation, as provided in Attachment N of this order. To ensure compliance with WCLUDO Section 19.030(C)(7) fire protection and emergency response requirements, the Department recommends Council impose the following condition:

Recommended Land Use Condition 7:

a. Prior to construction of the facility or any phase of the facility, the certificate holder shall submit a Construction Fire Prevention and Emergency Response Plan to the Department, for review and approval, in consultation with Wasco County Planning Department.

b. Prior to operation of the facility or any phase of the facility, the certificate holder shall submit an Operational Fire Prevention and Emergency Response Plan, consistent with the components included in the draft plan provided in Attachment N of the Final Order on the ASC.

c. The certificate holder shall demonstrate that the draft plans submitted under (a) and (b) of this condition were developed in consultation with the Oregon State Fire Marshal,

Based on the applicant’s representations described above, and compliance with recommended Land Use Condition 7, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(7).

8. Public Safety - A public safety plan shall be developed and implemented to exclude members of the public from hazardous areas within the Energy Facility Project Area.

WCLUDO Section 19.030(C)(8) requires that an applicant for a commercial power generating facility develop and implement a public safety plan to exclude members of the public from hazardous areas within the proposed facility area (or proposed microtubing corridor). The proposed facility would exclude members of the public by design installation of an 8-foot, chain-link perimeter fence around the entirety of the solar arrays. The proposed O&M building, collector substation, and battery storage systems would be located within this fenced area, with the collector substation being restricted from access through additional perimeter fencing. The applicant represents that public access restriction through perimeter fencing for public safety would be documented in its Fire Protection and Emergency Response Plan, which the Department recommends Council impose as Land Use Condition 7, referenced above. Based upon the applicant’s proposed perimeter fencing for the facility, and internal potentially hazardous facility components such as the substation, and verified through compliance with recommended Land Use Condition 7, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(8).

9. Transportation Plan - A transportation plan shall be developed and implemented in consultation with the Wasco County Road Department and/or the Oregon Department of Transportation (ODOT). The plan shall be consistent with any applicable requirements from the Wasco County Transportation System Plan and shall also provide or address:

a. The size, number, and location of vehicle access points off of public roads.
b. Use of existing roads to the extent practical to minimize new access roads.

c. Restoring the natural grade and revegetating all temporary road cuts, used during construction of the energy facility. The applicant shall specify the type and amount of native seed or plants used to revegetate the disturbed areas and a timeline to complete this work.

d. A Road Impact Assessment/Geotechnical Report for roads to be used by the project. Said report should include an analysis of project-related traffic routes to be used during phases of construction, project operation and decommissioning. The report and any subsequent amendments shall be used as a discipline study and shall be incorporated into the Road Use Agreement between the Applicant and the County.

WCLUDO Section 19.030(C)(9) requires that an applicant for a commercial power generating facility develop and implement a Transportation Plan that identifies public road access points, use of existing roads, road cut restoration measures, and includes a Road Impact Assessment/Geotechnical Report for public roads to be used/impacted. To address this criteria, the applicant commits to using existing roads to the extent practicable, and refers to the Road Approach Permits that would be obtained from Wasco County Public Works Department and ODOT, as applicable, and the Road Use Agreement with Wasco County Public Works Department as the mechanisms that would ensure that the details required under WCLUDO Section 19.030(C)(9) are satisfied. As presented in Section IV.M. Public Services, the Department recommends Council impose Public Services Condition 3, related to construction-related traffic minimization measures, road approach permits and road use agreements, with a built-in requirement that, prior to construction and as part of the road use agreement, the applicant (certificate holder) complete a Road Impact Assessment/Geotechnical Report for roads to be used during proposed facility construction – to then be used to inform level of road improvements and/or restoration.

Based upon the applicant’s representations and compliance with recommended Public Services Condition 3, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(9).

10. Road Use Agreement - Where applicable, the Wasco County Road Department shall require the applicant to enter into a Road Use Agreement with the County to ensure that project construction traffic is mitigated and any damage to county roads that is caused by the construction of the energy facility or its related or supporting facilities is repaired by the applicant, and such county roads are restored to pre-construction conditions or better (this includes a weed plan and providing for re-vegetation).

- General design standards for roads shall, in general, conform to policies set forth in Chapter 21.
- As part of the Road Use Agreement the applicant shall also obtain a utility permit for all project utility installation and approach permits for road approach access to county roads.

WCLUDO Section 19.030(C)(10) requires that an applicant for a commercial power generating facility execute a road use agreement with the Wasco County Road Department to ensure that construction-related traffic impacts to county roads are repaired to pre-construction conditions or better. The applicant commits to executing a road use agreement with the Wasco County Road Department in accordance with WCLUDO Section 19.030(C)(10), prior to construction. As described above, the Department recommends Council impose Public Services Condition 3, related to construction-related traffic minimization measures, road approach permits and road use agreements. Based upon the applicant’s representations and compliance with recommended Public Services Condition 3, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(10).

11. Onsite Access Roads and Staging Areas - The impact of onsite access roads and staging areas within the Energy Facility Project Area shall be limited by:

- a. Constructing and maintaining onsite access roads for all-weather use to assure adequate, safe and efficient emergency vehicle and maintenance vehicle access to the site;
- b. Using existing onsite access roads to the extent practical and avoiding construction of new on-site access roads as much as possible; and
- c. Restoring the natural grade and revegetating all temporary access roads, road cuts, equipment staging areas and field office sites used during construction of the energy facility. The applicant shall specify the type and amount of native seed or plants used to revegetate the disturbed areas and a timeline to complete this work.

WCLUDO Section 19.030(C)(11) requires a demonstration that a proposed commercial power generating facility would adhere to specific minimization measures to reduce potential impacts to onsite access roads and staging areas. In ASC Exhibit K, the applicant describes that onsite access roads would be graded and covered with gravel, all-weather surface. Construction of new access roads would be minimized to the extent possible, with use of existing access roads potentially limited by landowner preference. Temporary access roads and staging areas would be restored through gravel removal and revegetation consistent with pre-disturbance vegetation. The applicant is required to finalize its draft Revegetation Plan (see Attachment I of this order), in accordance with several conditions imposed through this order, which would ensure temporary impacts are restored and that success of restoration is monitored long term, to ensure limiting factors such as unsuccessful seeding, weeds or fire don’t impact revegetation success. Based on compliance with the requirements of the draft Revegetation Plan, as imposed in recommended Fish and Wildlife Condition 1, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(11).

12. Dust Control - All approved non-paved temporary or permanent roads and staging areas within the Energy Facility Project Area shall be constructed and maintained to minimize dust, which may be addressed through the Road Use Agreement. If roads and staging areas are not construct with material that would
WCLUDO Section 19.030(C)(12) requires a demonstration that a proposed commercial power generating facility would minimize and control dust. Proposed facility construction would generate dust, which the applicant commits to controlling through daily water application via water truck. Additional dust control measures identified by the applicant include graveling of permanent roads, revegetation of temporarily disturbed areas, and imposing a 20 mile per hour speed limit. Based on implementation of the applicant’s proposed dust control measures, the Department recommends Council find that the applicant would satisfy Section 19.030(C)(12).

13. Erosion and Sediment Control - All ground disturbing activities shall be conducted in compliance with a National Pollutant Discharge Elimination System (NPDES) permit as may be required by Oregon Department of Environmental Quality. Where applicable, an NPDES permit must be obtained. The plan must include best management practices for erosion control during construction and operation and permanent drainage and erosion control measures to prevent damage to local roads or adjacent areas and to minimize sediment run-off into waterways.

WCLUDO Section 19.030(C)(13) requires a demonstration that a proposed commercial power generating facility would adhere to the requirements of a DEQ-issued NPDES 1200-C permit to minimize erosion and implement sediment control. The applicant identifies that a NPDES 1200-C permit would be required for proposed facility construction, which the Department recommends be obtained and complied with under Soil Protection Condition 1. Based on compliance with recommended Soil Protection Condition 1, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(13).

14. Weed Control - A weed plan shall be developed in consultation with the Wasco County Weed Department and implemented during construction and operation of the energy facility.

WCLUDO Section 19.030(C)(14) requires a permittee of a proposed commercial power generating facility to develop a Weed Control Plan, in consultation with the Wasco County Weed Department, to be implemented during construction and operation. In accordance with this criteria, the applicant developed a draft Noxious Weed Control Plan, as provided in Attachment X of this order, and consulted with Wasco County Weed Department Supervisor – Merle Keys. Additionally, the Department consulted with Merle Keys on December 11, 2019, where Mr. Keys confirmed that he had reviewed the draft plan and confirmed that it was adequate and had no additional comments. Development and implementation of a Noxious Weed Control Plan is required under various Council standards (Fish and Wildlife Habitat, Land Use) and LCDC’s solar rules; therefore, the Department recommends Council impose Fish and Wildlife Habitat Condition 2, requiring that the applicant finalize the plan, in consultation with the Department and County Weed Control Supervisor, and implement and adhere to the

15. Signs - Outdoor displays, signs or billboards within the energy facility project boundary shall not be erected, except:
   a. Signs required for public or employee safety or otherwise required by law; (e.g., OSHA or compliance with the Manual of Uniform Traffic Control Devices (MUTCD) administered through the County Road Department); and
   b. No more than two signs relating to the name and operation of the energy facility of a size and type to identify the property for potential visitors to the site, but not to advertise the product. No signs for advertising of other products are permitted.

WCLUDO Section 19.030(C)(15) requires a permittee of a proposed commercial power generating facility to adhere to limitations of erecting signs, including only signs for safety and no more than two signs relating to site access and facility name. The applicant commits to complying with this limitation. To provide the Department and the county the opportunity to verify compliance with this sign limitation, the Department recommends Council impose the following condition:

Recommended Land Use Condition B: During construction and operation of the facility or any phase of the facility, the certificate holder shall prohibit posting of any advertising signs. If the facility posts external signage (i.e. outdoor displays, signs or billboards), such signage shall be limited to safety signs and no more than two signs presenting the facility name. [GEN-LU-03]

Based on compliance with recommended Land Use Condition B, and the applicant’s commitment to complying the criteria, the Department recommends Council find that the applicant would satisfy WCLUDO Section 19.030(C)(15).

16. Underground Systems - Where reasonably practicable, power collector and communication systems shall be installed underground, at a minimum depth of 3 feet. Shallower depths may be authorized where notification and safety measures are taken and wires are placed in schedule 40 conduit. The cable collector system shall be installed to prevent adverse impacts on agriculture operations and natural resources.

WCLUDO Section 19.030(C)(16) requires a permittee of a proposed commercial power generating facility to install power collection and communication systems belowground surface at a minimum depth of 3 feet. The applicant proposes and commits to installing underground collector lines at a minimum of 3 feet below ground surface. Based on the applicant’s proposed design and belowground burial depth, the Department recommends Council find that the proposed facility would satisfy WCLUDO Section 19.030(C)(16).
Consistent with WCLUDO Section 19.030(C)(18), the Department recommends Council impose
the following condition to ensure that the applicant obtains and provides evidence to the
Department and Wasco County that all necessary permits have been obtained prior to
construction.

Recommended Land Use Condition 9: Prior to construction of facility components

1. Note permits and approvals have been obtained including a conditional use

2. zoning permit, building permit, utility crossing permit, access approach site permit, and

3. road use agreement.

4. Any necessary state and local permits have been obtained by its third-party contractors,

5. specifically and as applicable, a DEQ-issued onsite sewage disposal construction-

6. installation permit (O&M building), a DEQ-issued General Water Pollution Control

7. Facilities Permit (temporary concrete batch plant), Department of Water Resources-

8. issued limited water use license (O&M well).

9. The building will be removed or converted to another approved use upon

10. expiration of the certificate for the proposed facility.

11. The building is designed and constructed generally consistent with the

12. character of similar buildings used in the surrounding area; and

13. deemed to be in compliance with the

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17. Final Proposed Order

Oregon Department of Energy

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estimate and financial assurance may take into account salvage value associated with the project, and can be requested for review and update by Wasco County at their discretion (e.g., every 5 years).

c. The following shall be required as conditions of the Wasco County approval:

1. If operation of the energy facility ceases or begins construction of the project, but does not complete it, the permit holder shall restore the site according to a plan approved by Wasco County. A plan shall be submitted that ensures the site will be restored to a useful, non-hazardous condition without significant delay, including but not limited to the following:

   (a) Removal of aboveground and underground equipment, structures and foundations to a depth of at least three feet below grade (four feet if cropland). Underground equipment, structures and foundations need not be removed if they are at least three feet below grade and do not constitute a hazard or interfere with agricultural use or other resource uses of the land. Restoration of the surface grade and soil after removal of aboveground structures and equipment.

   (b) Removal of gravelled areas and access roads and restoration of surface grade and soil.

   (c) Revegetation of restored soil areas with native seed mixes, plant species suitable to the area, consistent with Wasco County’s weed control plan.

   (d) For any part of the energy facility on leased property, the plan may incorporate agreements with the landowner regarding leaving access roads, fences, gates or buildings in place or regarding restoration of agricultural crops or forest resource land. Said landowner will be responsible for maintaining said facilities for purposes permitted under applicable zoning.

   (e) The underground power collector and communication lines need not be removed if at a depth of three feet or greater. These cables can be abandoned in place if they are deemed not a hazard or interfering with agricultural use or other consistent resource uses of the land.

   (f) The plan must provide for the protection of public health and safety and for protection of the environment and natural resources during site restoration.

   (g) The plan must include a schedule for completion of site restoration work.

2. Before beginning construction of the energy facility, the permit holder must submit in a form and amount satisfactory to Wasco County, assuring the availability of adequate irrevocably committed funds to restore the site to a useful, non-hazardous condition naming Wasco County as beneficiary or payee. The form and amount may include posting a bond, issuing an irrevocable letter of credit, purchasing a paid up insurance policy or by other means acceptable by Wasco County and shall ensure continuity between owners.

3. The amount of the financial assurance (bond or other such form of guarantee) shall be annually adjusted for inflation using the U.S. Grass Domestic Product Implicit Price Deflator, Chain-Weight, as published in the Oregon Department of Administrative Services’ “Oregon Economic and Revenue Forecast,” or by any successor agency (the “Index”). The permit holder (including possible successor if sold or transferred) shall increase the amount of the financial assurance annually by the percentage increase in the Index and shall pro-rate the amount within the year to the date of retirement. If at any time the Index is no longer published, Wasco County shall select a comparable index for adjusting the amount. The amount of the financial assurance shall be prorated within the year to the date of decommissioning.

4. Per the request of Wasco County, the permit holder (including possible successor if sold or transferred) shall describe the status of the financial assurance in a report (e.g., annual update report submitted to Wasco County).

5. The financial assurance shall not be subject to revocation or reduction before retirement of the energy facility site.

WCLUDO Section 19.030(C)(19) requires a permittee of a proposed commercial power generating facility to satisfy specific termination and decommissioning requirements, including cost estimating and submittal of a bond or letter of credit. The criteria specifically allows EPSC-Jurisdictional facilities to comply with those provisions through compliance with the Council’s Retirement and Financial Assurance standard, but also allows a permittee to consider an index value in its decommissioning security formula. The Department finds that this applicable substantive criterion provides support for the applicant’s proposed alternate decommissioning method, presented in Section IV G Retirement and Financial Assurance below. As presented in Section IV G, Retirement and Financial Assurance of this order, based upon compliance with recommended conditions, the Department recommends Council find that the applicant would satisfy the requirements of the Council’s standard under one of two methods; and therefore, based upon this recommended conclusion, the Department recommends Council find that the applicant would also satisfy the requirements of WCLUDO Section 19.030(C)(19).

20. Final Location - The actual latitude and longitude location or Oregon State Plane NAD83 HARN (international foot) coordinates of the energy facility and related or supporting facilities shall be provided to the County GIS Department once commercial electrical power production begins. Alternatively, this information could be provided in GIS layer consistent with the datum referenced above or any other datum deemed acceptable by the Wasco County GIS Department.

WCLUDO Section 19.030(C)(20) requires that, once permitted, a commercial power generating facility provide the actual latitude and longitude location, or other acceptable format, of all facility components to the governing body. This zoning provision is not substantive criteria for which the Council need make findings; however, because the information supports future planning and is an information requirement, the Department recommends Council impose the following condition:
Recommended Land Use Condition 10: Within 90 days of commercial operation of the facility or any phase of the facility, the certificate holder shall provide to the Department and Wasco County GIS Department the actual latitude and longitude location or Oregon State Plan NDA83 HARN (international feet) coordinate of all facility components. GIS layers may be provided consistent with the datum reference above or any other datum deemed acceptable by the Department. [OPR-LU-01]

21. Power Production Reporting - The County may require a report of nonproprietary power production for any timeframe after energy facility first begins production if permitted through the County. If requested, the permit holder shall have 180 days to produce said report.

WCLUDO Section 19.030(D)(25) provides authority to the governing body of a permitted commercial power generating facility to request a report of nonproprietary power production for any timeframe after commercial operation, and is therefore not considered applicable substantive criteria for which Council needs to make findings. Wasco County Board of Commissioners did not request that Council impose a condition requiring that the applicant submit a nonproprietary power production report, and therefore is not included in this order.

Specific Standards, Solar Energy Facilities

D. Specific Standards - The following standards apply to specific types of energy facilities as described, in addition to the General Standards in Section C above.

a. Solar Energy Facilities:

1. Ground Leveling - The solar energy facility shall be designed and constructed to minimize ground leveling and to the extent reasonably practicable, limit ground leveling to those areas needed for effective solar energy collection.

2. Misdirection of Solar Radiation - The solar energy facility shall be designed, constructed, and operated to prevent the misdirection of concentrated solar radiation onto nearby properties, public roadways or other areas accessible to the public, or mitigated accordingly.

3. Glare - The solar energy facility shall be designed, constructed and operated such that any significant or prolonged glare is directed away from any nearby properties or public roadways, or mitigated accordingly.

4. Cleaning Chemicals and Solvents - During operation of the solar energy facility, all chemicals or solvents used to clean solar panels or heliostats shall be low in volatile organic compounds and to the extent reasonably practicable, the permit holder shall use recyclable or biodegradable products.

5. Wildlife - Measures to reduce wildlife impact may include using suitable methods such as coloration or sound producing devices to discourage

WCLUDO Section 19.030(D) establishes specific standards for a commercial power generating facility that is a solar energy facility, including ground leveling, misdirection of solar radiation, glare, cleaning chemicals and solvents, and wildlife impact minimization measures. The solar energy facility criteria for misdirection of solar radiation and wildlife impact minimization measures are specific to solar facilities proposing to use concentrated solar radiation technology, which are not applicable to the proposed facility (proposing photovoltaic solar panels) and not further evaluated below.

In response to WCLUDO Section 19.030(D)(a), the applicant describes that the proposed facility site is relatively flat and therefore would not be expected to require significant leveling of ground surfaces which may otherwise be necessary to provide flat terrain for siting of proposed facility components. In response to WCLUDO Section 19.030(D)(c), the applicant confirms that the proposed facility would include modules designed with antireflective technology – limiting potential glare – and that the design of the modules includes tracking systems that would rotate the modules, further reducing any potential glare impacts in any one location. In response to WCLUDO Section 10.030(D)(d), the applicant explains that solar panel washing may occur up to two times per year, and that recyclable or biodegradable products would be used, to the extent reasonably practicable. To ensure compliance with WCLUDO Section 19.030(D)(e), the Department recommends Council impose the following condition:

Recommended Land Use Condition 11: During operation of the facility or any phase of the facility, the certificate holder shall use copies of the Chemical Safety Data Sheets (SDS) for cleaning chemicals and solvents that are recyclable and biodegradable. The SDSs must demonstrate that the cleaning products for solar panel washing that are used are low in volatile organic compounds and, to the extent feasible, are recyclable or biodegradable products. If the product is not recyclable or non-biodegradable, the certificate holder shall provide an explanation and demonstrate that an evaluation of the availability of recyclable and biodegradable products was completed. During any year of operation, the certificate holder shall copy and provide updated SDSs to the Department if the cleaning products change.

Based on proposed facility design and compliance with the above-recommended condition, the Department recommends Council find that the applicant would also satisfy the requirements of WCLUDO Section 19.030(D).

Section 20.050, Approval Standards

A. All provisions of this ordinance and other applicable ordinances are complied with.
Section 20.055 Bicycle Parking Requirements

1. At the time of erection of a new structure or at the time of enlargement or change in use of an existing structure, bicycle parking shall be provided in accordance with the following standards:
   a. Number of Bicycle Parking Spaces - A minimum of two (2) bicycle parking spaces per use is required for all uses with greater than 10 vehicle parking spaces.
   b. Location and Design - Bicycle parking shall be conveniently located with respect to both the road right-of-way and at least one building entrance (e.g., no farther away than the closest parking space). It should be incorporated whenever possible into building design and coordinated with the design of street furniture when it is provided.
   c. Street furniture includes benches, street lights, planters and other pedestrian amenities.
   d. Visibility and Security - Bicycle parking shall be visible to cyclists from roadway sidewalks or building entrances, so that it provides sufficient security from theft and damage;
   e. Options for Storage - Bicycle parking requirements for long-term and employee parking can be met by providing a bicycle storage room, bicycle lockers, racks, or other secure storage space inside or outside of the building;
   f. Lighting - Bicycle parking shall be least as well-lit as vehicle parking for security;
   g. Reserved Areas - Areas set aside for bicycle parking shall be clearly marked and reserved for bicycle parking only;
   h. Hazards - Bicycle parking shall not impede or create a hazard to pedestrians. Parking areas shall be located to avoid conflict with vision clearance standards (Section 4.090 Vision Clearance).

WCLUDO Section 20.055 establishes bicycle parking requirements, including a minimum of 1 bicycle parking space for parking lots with less than 10 parking spaces, which the applicant asserts would be satisfied through the O&M building parking lot design. Based on the O&M parking lot design (1 bicycle space) and maximum number of workers (10), the Department recommends Council find that the proposed facility would comply with Section 20.055.

Section 20.070 Off Street Loading

b. Merchandise, materials or supplies: Buildings or structures to be built or substantially altered to receive and distribute materials or merchandise by truck shall provide and maintain off street loading berths in sufficient numbers and size to adequately handle the needs of the particular use. If loading space has been provided in connection with an existing use or is added to an existing use, the loading space shall not be eliminated if elimination would result in less space than is required to adequately handle the needs of the particular use. Off street parking areas used to fulfill the requirements of this Ordinance shall not be used for loading and unloading operations except during periods of the day when not required to take care of parking needs.
protected under WCCP Chapter 5J Subpart 3 establishes outstanding scenic and recreational areas as natural spaces for up to 10 vehicles and 1 bicycle. The applicant asserts would be satisfied through O&M building design, which includes sufficient street parking and loading provisions, which the applicant asserts would be satisfied by the design of the proposed O&M building yard design. Based on the proposed O&M building design, the Department recommends Council find that the proposed facility would comply with WCLUDO Section 5.020(G), the Department recommends Council find that the proposed facility would either not result in or would minimize air quality, water quantity and quality and land resource impacts. Therefore, the Department recommends Council find that the proposed facility would not consistent with this policy.

Policy 4: Noise levels should be maintained in compliance with state and federal standards. Implementation
- Noise levels for all new industries must be kept within standards set by state and federal agencies.
- Consideration for the effects of noise on the surrounding environment will be given when a new development of any kind is proposed.
- Noise sensitive areas should be identified and only compatible uses permitted in their vicinity.

WCCP Goal 6 Policy 4 is implemented in WCLUDO Section 5.020(B) and (E). As presented in the evaluation of WCLUDO Section 5.020(B) and (E), the Department recommends Council find that the proposed facility would comply with DEQ's noise control rules and based upon compliance evaluation of WCLUDO Section 5.020(E), the Department recommends Council find that the proposed facility would be consistent with policies aimed at protecting fish and wildlife habitat.

Based on the proposed O&M building design, the Department recommends Council find that the proposed facility would comply with Section 20.070.

Policy 1: Encourage land uses and land management practices which preserve both the quantity and quality of air, water and land resources. Implementation
- Air, Water and Land Resources Quality: To maintain and improve the quality of the air, and land resources of the County.

WCCP Goal 6 Policy 1 is implemented in WCLUDO Section 5.020(C). As presented in the evaluation of WCLUDO Section 5.020(C), the Department recommends Council find that the proposed facility would either not result in or would minimize air quality, water quantity and quality and land resource impacts. Therefore, the Department recommends Council find that the proposed facility would be consistent with this policy.

Policy 2: Commercial and industrial development compatible with the County's federal, state and local agencies.

Policy 3: Wasco County will support the expansion and increased productivity of existing industries and firms as a means to strengthen local and regional economic development.
recommends Council find that the proposed facility would be consistent with this policy.

GOAL #11 – PUBLIC FACILITIES AND SERVICES: To plan and develop a timely, orderly and efficient arrangement of public facilities and services to serve as a framework for urban and rural development.

Policy 1: Provide an appropriate level of fire protection, both structural and wildland, for rural areas.

WCCP Goal 11 Policy 1 is implemented in WCLUDO Chapter 10. As presented in the evaluation of WCLUDO Section 19.030(C), and based upon compliance with recommended Public Services Condition 3, the Department recommends Council find that the proposed facility would be consistent with this policy.

Policy 3: Minimize adverse impacts resulting from power line corridor and utility development.

B. When economically and physically feasible, transmission lines should be laid underground.

****

E. Maximum utilization of existing utility rights-of-way should be encouraged to minimize the need for additional rights-of-way.

WCCP Goal 11 Policy (B) and (E) is implemented in WCLUDO Section 3.214(L) and ORS 215.274,

which are evaluated in this order. As presented in the evaluation of WCLUDO Section 3.214(L) and ORS 215.274 of this order, the Department recommends Council find that the proposed facility would be locationally dependent and there is a lack of an available right of way for the entire length of the proposed transmission line. Therefore, the Department recommends Council find that the proposed facility would be consistent with this policy.

GOAL #12 – TRANSPORTATION: To provide and encourage a safe, convenient and economic transportation system.

Policy 1: Develop and maintain an adequate County road system.

WCCP Goal 12 Policy 1 is implemented in WCLUDO Section 19.030(C), which is evaluated in this order. As presented in the evaluation of WCLUDO Section 19.030(C), and based upon compliance with recommended Public Services Condition 3, the Department recommends Council find that the proposed facility would be consistent with this policy.

GOAL #13 – ENERGY CONSERVATION: To conserve energy.

Policy 1: The County will work with appropriate State and Federal agencies to identify and protect, and if feasible, develop potential energy resources, especially renewable energy resources.

Policy 2: Reduce the consumption of non-renewable sources of energy whenever possible.

A. Conversion of energy sources from non-renewable sources to renewable sources shall be encouraged.

B. The allocation of land and uses permitted on the land should seek to minimize the depletion of non-renewable sources of energy.

Policy 6: Use of renewable energy shall be encouraged.

WCCP Goal 13 Policies 1, 2 and 3 are directives to the county related to renewable resources. Because the proposed facility is a renewable resource, the Department recommends Council find that the proposed facility would be consistent with these policies.

Directly Applicable State Statutes and Administrative Rules

ORS 215.283(1)(c) and ORS 215.274 – Associated Transmission Lines Necessary for Public Service

Transmit lines that meet the definition of an “associated transmission line” must consider the requirements of ORS 215.274. If a utility facility necessary for public service is an
“associated transmission line” as defined in ORS 215.274 and ORS 469.300, the use may be
established in EFU-zoned land pursuant to ORS 215.238(c).
ORS 469.300(3) defines “associated transmission lines” as “new transmission lines constructed
to connect an energy facility to the first point of junction of such transmission line or lines with
either a power distribution system or an interconnected primary transmission system or both
or to the Northwest Power Grid,” and that definition is incorporated by reference in ORS
215.274. Associated transmission lines reviewed under ORS 215.274 are a subset of the
existing proposed collector substation or or an interconnected primary transmission system or both.
ORS 215.274(3): The associated transmission line is necessary for public service under
ORS 215.274. The proposed collector substation to the northwest power grid through interconnection to BPA’s
existing Maupin Substation (see Figure 3: Proposed Facility Layout in Section III., Proposed
Facility Location, Site Boundary and Microsizing Corridor of this order). As such, the proposed
230 kV transmission line is an “associated transmission line.” Wasco County has not adopted
local code provisions to implement ORS 215.274. Therefore, the requirements of the statute
apply directly to the proposed 230 kV transmission line and the applicable requirements are
evaluated below.
ORS 215.274(2): An associated transmission line is necessary for public service if an
applicant for approval under ORS 215.213 (Uses permitted in exclusive farm use zones in
counties that adopted marginal lands system prior to 1993) (1)(c)(B) or 215.283 (Uses
permitted in exclusive farm use zones in nonmarginal lands counties) (1)(c)(B) demonstrates
the governing body of a county or its designee that the associated transmission line
meets:
(a) At least one of the requirements listed in subsection (3) of this section; or
(b) The requirements described in subsection (4) of this section.
ORS 215.274 requires that the applicant demonstrate that the associated transmission line
meets the requirements of either ORS 215.274(3) or (4). As discussed below, in ASC Exhibit K,
the applicant provides evidence to support Council’s review of the requirements of subsection
(4), the applicant acknowledges that it does not meet the requirements of subsection (3).
ORS 215.274(3): The governing body of a county or its designee shall approve an application
under this section if an applicant demonstrates that the entire route of the associated
transmission line meets at least one of the following requirements:
(a) The associated transmission line is not located on high-value farmland, as
defined in ORS 195.300 (Definitions for ORS 195.300 to 195.336), or on arable
land;
(b) The associated transmission line is co-located with an existing transmission line;
ORS 215.274(4)(a): Except as provided in subsection (3) of this section, the governing body of
each county or its designee shall approve an application under this section if, after an
evaluation of reasonable alternatives, the applicant demonstrates that the entire route of
the associated transmission line meets, subject to paragraphs (b) and (c) of this subsection,
two or more of the following factors:
(a) At least one of the requirements listed in subsection (3) of this section; or
(b) The requirements described in subsection (4) of this section.
ORS 215.274(4)(b) requires an evaluation of reasonable alternatives to determine whether the
associated transmission line may be sited on land other than EFU-zoned land. The evaluation of
“reasonable alternatives” does not require an evaluation of all alternative EFU-zoned routes on
which the transmission line could be located. Rather, the applicant must consider reasonable
alternatives and show that the transmission line must be sited on EFU-zoned land in order to
provide the service.
In ASC Exhibit K, the applicant describes that, based on the proposed interconnection of the
proposed facility to BPA’s existing Maupin Substation, a fixed endpoint, and the proposed
facility location, there are no alternative alignments that would avoid EFU-zoned land. As
presented in Figure 3, Zoning and Comprehensive Plan Designations, the area within the site
boundary, the 0.5 mile analysis area and further surrounding area is EFU-zoned land.
Nonetheless, the applicant considered three alternative transmission line routes, that while located on EFU zoned land, are represented as minimizing impacts to arable lands by co-locating the transmission line on existing transmission infrastructure or existing rights-of-way.

Generally, the proposed alternative routes considered are as follows:

- Co-location of the proposed 230 kV transmission line with Wasco Electric Cooperative’s existing 65 kV transmission line, which runs southeast from the Maupin Substation, generally along Bakeoven Road toward US 97, and passes within approximately 3,300 feet of the proposed collector substation.
- Placement of the proposed 230 kV transmission line within a new right-of-way that would parallel the existing Wasco Electric Cooperative 65 kV transmission line.
- Co-location of the proposed 230 kV transmission line within the Bakeoven Road right-of-way.

As presented in Figure 3, Zoning and Comprehensive Plan Designations, the entire proposed site boundary and proposed transmission interconnection point would be located within EFU zoned land. Therefore, there is no non-EFU zoned land between the proposed solar facility and the interconnection point, BPA’s Maupin Substation, that provide an alternative route. The Department therefore recommends Council find that the applicant has evaluated reasonable alternatives and demonstrates that no reasonable alternatives that would avoid EFU land exist. However, note that ORS 215.274(4) requires both a demonstration that no reasonable alternatives that would avoid EFU land exist, and that two or more of the listed factors [ORS 215.274(a)(A) through (E)] be met, which is evaluated below.

ORS 215.274(a)(A): Technical and engineering feasibility;

ORS 215.274(a)(B) provides that an applicant may demonstrate that the proposed transmission line must be sited in an EFU zone due to technical and engineering feasibility constraints. The Department interprets this factor as requiring a demonstration that technical or engineering constraints, such as extreme topographic features, cannot be overcome but for facility engineering through EFU zoned land.

The applicant, in contrast, evaluates the technical and engineering feasibility of the above-described alternative routes and compared the feasibility of constructing alternative routes to the proposed route based on differences in existing infrastructure and access. All of the routes – the proposed and three alternative routes – would be located within EFU zoned lands; and, as described under the evaluation of ORS 215.274(a) above, non EFU zoned land does not exist within or surrounding the proposed site boundary. Therefore, the Department recommends Council find that technical or engineering constraints, such as extreme topographic features, that could not be overcome but for siting the proposed 230 kV transmission line through EFU zoned land were not the primary drivers for siting the proposed transmission line on EFU zoned land. ORS 215.274(a)(A) would not be satisfied.

ORS 215.274(a)(B): The associated transmission line is locationally dependent because the associated transmission line must cross high-value farmland, as defined in ORS 195.300 (Definitions for ORS 195.300 to 195.336), or arable land to achieve a reasonably direct route or to meet unique geographical needs that cannot be satisfied on other lands;

ORS 215.274(a)(B) provides that an applicant may demonstrate that the proposed transmission line must cross high value farmland or arable land to achieve a reasonably direct route and therefore is locationally dependent. For the proposed 230 kV transmission line, the analysis focuses on the availability of non-arable land because the proposed transmission line would not be located on or within high-value farmland as defined in ORS 195.300(10).

As presented in ASC Exhibit K Figure K-5, Arable and Non-Arable Lands, the proposed 230 kV transmission line route is surrounded by interspersed, patchy and highly irregularly shaped areas of arable land, creating challenges in proposing a relatively linear transmission line route from the proposed facility site to the grid-interconnection point at BPA’s existing Maupin Substation, if impacts to arable lands were attempted to be avoided. The applicant asserts that...
the proposed 230 kV transmission must cross arable land to achieve a reasonably direct route because the proposed facility site contains specific geographic characteristics necessary to support facility operation, slopes below 15 percent and adequate distance from sun-blocking landforms or objects, and BPA’s Maunin Substation, as an existing facility, is a fixed point location. While not required, the applicant provides an analysis of the three alternative routes considered, which would minimize impacts to arable lands by utilizing existing infrastructure or new rights-of-way, but determined the alternative routes to be infeasible due to topography constraints, lack of easements, and insufficient space and infrastructure capacity.

Because there is no reasonable route to interconnect the proposed collector substation to BPA’s Maunin Substation without traversing arable land, the Department recommends Council find that the proposed 230 kV transmission line must cross arable land to achieve a reasonably direct route, and that the associated transmission line is therefore “locationally dependent” and would satisfy ORS 215.274(4)(a)(B).

ORS 215.274(4)(a)(C) - Lack of an available existing right of way for a linear facility, such as a transmission line, road or railroad, that is located above the surface of the ground;

ORS 215.274(4)(a)(C) provides that an applicant may demonstrate a lack of available existing linear facility rights-of-way for which the proposed transmission line could be located. To inform this criterion, the applicant evaluates the availability and feasibility of siting the proposed 230 kV transmission line within Bakeoven Road right-of-way. The Bakeoven Road right-of-way is 60-feet wide and contains Wasco Electric Cooperative’s 65 kV transmission line. The applicant explains that a minimum fall distance separation equal to the transmission structure height of 80 to 100 feet, plus 10 percent, or a minimum of 88 feet must be maintained between the existing 65 kV and proposed 230 kV transmission line to limit system reliability impacts, and therefore the available space within the existing right-of-way is not sufficient to accommodate the proposed transmission line. For high voltage lines, the Western Electricity Coordinating Council recommends a minimum fall distance separation of 250 feet, which is typically extended by individual utility company design standards up to 1,500 feet. Based on the reasoning provided above and evaluation of availability of the existing road right of way, as presented in ASC Exhibit K, the Department recommends the Council find that the proposed 230 kV transmission line would satisfy ORS 215.274(4)(a)(C).

ORS 215.274(4)(a)(D) - Public health and safety;

ORS 215.274(4)(a)(D) provides that the applicant may demonstrate that the proposed transmission line must be sited on EFU zoned land to minimize potential impacts to public health and safety. For this ASC, the applicant has not requested Council consideration of this criterion.

ORS 215.274(4)(E): Other requirements of state or federal agencies.

ORS 215.274(4)(E) provides that the applicant may demonstrate that the proposed transmission line must be sited in an EFU zone due to other state or federal requirements. For this ASC, the applicant has not requested Council consideration of this criterion.

ORS 215.274(4)(F): The applicant shall present findings to the governing body of the county or its designee on how the applicant will mitigate and minimize the impacts, if any, of the associated transmission line on surrounding lands devoted to farm use in order to prevent a significant change in accepted farm practices or a significant increase in the cost of farm practices on the surrounding farmland.

ORS 215.274(4)(b) requires that the applicant demonstrate that the proposed transmission line would not result in a significant change in accepted farm practices or a significant increase in cost of farm practices on surrounding land. The area surrounding the proposed site boundary (i.e. within 0.5 miles) is primarily used for grazing, within limited dryland wheat and other row crop cultivation. As presented in ASC Exhibit K Figure K-3 Existing Land Use and Water Rights, the proposed 230 kV transmission line would be located entirely within non-cultivated lands, and therefore would avoid direct impacts to agricultural practices. Cattle or sheep grazing could still occur around the transmission line poles. The applicant also represents that permanent disturbance within EFU zoned land from the proposed 230 kV transmission line would be negligible (i.e., less than 0.1 acre) based on approximately 84 pole structures, each resulting in 40 square feet of permanent disturbance. Because the area crossed by the transmission line is not used for cultivated crops, the transmission line would not affect other types of agricultural practices that would be associated with crop cultivation. The applicant further asserts that landowners would continue to have access to their land, once the transmission line was in place, minimizing impacts to access or use of the land from siting of the energy infrastructure.

Based on the avoidance of direct impacts to agricultural practices, minimal amount of permanent impacts within EFU-zoned land, and the availability of continued access and use of the land by underlying landowners, the Department recommends Council find that the proposed 230 kV transmission line would satisfy 215.274(4)(b).

ORS 215.274(4)(G): The governing body of a county or its designee may consider costs associated with any of the factors listed in paragraph (a) of this subsection, but consideration of cost may not be the only consideration in determining whether the associated transmission line is necessary for public service.

ORS 215.274(4)(G) allows for consideration of costs in determining whether the associated transmission line is necessary for public service. The applicant indicates that, based on its review of three alternative routes and the increased length of those routes, construction costs...
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would increase. Although this subsection does not require the consideration of costs, the
Department acknowledges that if the transmission line were to utilize Bakeoven Road rights of
ways, the length of the transmission line would increase and the certificate holder would be
required to obtain new land rights; these changes would increase costs associated with the
transmission line.

For the above stated reasons, the Department recommends that the Council find that the
applicant provides a sufficient alternative analysis required under ORS 215.274(4)(a), that the
associated transmission line is locationally dependent under ORS 215.274(4)(a)(b) and that
there is a lack of available existing right of way for a linear facility under ORS 215.274(4)(a)(C).
As such, the Department recommends that the Council find that the associated transmission
line is "necessary for public service."

Oregon Administrative Rules

OAR 660-033-0130(38) – Standards for Approval for Photovoltaic Solar Power Generation
Facility in Exclusive Farm Use Zones

(g) For high-value farmland described at ORS 195.300(10), a photovoltaic solar power
generation facility shall not use, occupy, or cover more than 12 acres unless:

1. The provisions of paragraph (h)(h) are satisfied; or

2. A county adopts, and an applicant satisfies, land use provisions authorizing
projects subject to a dual-use development plan. Land use provisions adopted by a
county pursuant to this paragraph may not allow a project with a nominal electric
generating capacity greater than 3 Mw or in excess of 20 acres. Land use provisions
adopted by the county must require sufficient assurances that the form use element
of the dual-use development plan is established and maintained so long as the
photovoltaic solar power generation facility is operational or components of the
facility remain on site.

3. OAR 660-033-0130(38)(h)(g) restricts a photovoltaic solar power generation facility from using,
occupying, or covering more than 12 acres of high-value farmland unless the provisions of OAR
660-033-0130(38)(h)(h) are satisfied or the County adopts a dual-use development plan, which
would then allow use, occupation or coverage on no more than 20 acres of high-value
farmland. Neither of these provisions are applicable to the proposed facility as the extent of
high-value farmland within the micrositing corridor is limited to 10.8 acres, of which only 10
square feet would be impacted. Therefore, because there is less than 12 acres within the
micrositing corridor that could be impacted, and the applicant estimates that proposed facility
impacts would result in the use, occupation or coverage of less than 10 square feet of high-
value farmland, considerably less than the 12 acre threshold, the Department recommends

(h) The following criteria must be satisfied in order to approve a photovoltaic solar power
generation facility on high value farmland described at ORS 195.300(10):

1. The proposed photovoltaic solar power generation facility will not create
unnecessary negative impacts on agricultural operations conducted on any
portion of the subject property not occupied by project components. Negative
impacts could include, but are not limited to, the unnecessary construction of
roads dividing a field or multiple fields in such a way that creates small or
isolated pieces of property that are more difficult to farm, and placing
photovoltaic solar power generation facility project components on lands in a
manner that could disrupt common and accepted farming practices;

2. The presence of a photovoltaic solar power generation facility will not result in
unnecessary soil erosion or loss that could limit agricultural productivity on the
subject property. This provision may be satisfied by the submittal and county
approval of a soil and erosion control plan prepared by an adequately qualified
individual, showing how unnecessary soil erosion will be avoided or remedied.
The approved plan shall be attached to the decision as a condition of approval;

3. Construction or maintenance activities will not result in unnecessary soil
compaction that reduces the productivity of soil for crop production. This
provision may be satisfied by the submittal and county approval of a plan
prepared by an adequately qualified individual, showing how unnecessary soil
compaction will be avoided or remedied in a timely manner through deep soil
decomposition or other appropriate practices. The approved plan shall be
attached to the decision as a condition of approval;

4. Construction or maintenance activities will not result in the unabated
introduction or spread of noxious weeds and other undesirable weed species. This
provision may be satisfied by the submittal and county approval of a weed control
plan prepared by an adequately qualified individual that includes a long-term
maintenance agreement. The approved plan shall be attached to the decision as a
condition of approval;

5. OAR 660-033-0130(38)(h)(h) – (D) requires a demonstration that the proposed photovoltaic
solar power generation facility would not create unnecessary negative impacts to agricultural
operations, soil erosion or loss, soil compaction, or the unabated introduction or spread of
noxious weeds:

a. OAR 660-033-0130(38)(h)(h)(A) Unnecessary Negative Impacts to Agricultural Operations

b. OAR 660-033-0130(38)(h)(h)(A) requires a demonstration that the proposed facility would not
create unnecessary negative impacts to agricultural operations, such as dividing a field or
multiple fields or placing facility components on lands in a manner that could disrupt accepted
farming practices. For this analysis, impacts from the proposed 230 kV transmission line are not
Construction and operation of the proposed solar facility would result in impacts to EFU-zoned land, including the use, occupation or covering of approximately 2,717 acres of agricultural lands by proposed solar facility components. Other than these direct impacts to EFU-zoned lands, construction related impacts would be minimal, such as potential short-term traffic delays and dust generation. The applicant commits to implementation of a Construction Traffic Management Plan (see proposed best management practices in Attachment M of this order) and application of water during dust-generating activities (site preparation; road construction; and, concrete foundation work), which would minimize short-term impacts to agricultural practices within the area. Operational impacts would not be expected as the proposed solar facility would not result in impacts outside of the perimeter fenceline, other than activities associated with ongoing noxious weed control and revegetation of temporarily disturbed areas.

Direct impacts to agricultural lands from the proposed solar facility would be limited to approximately 123 acres within over 3,654 acres of arable land. Potential impacts to high-value farmland would be negligible as there are approximately 323 acres within over 3,654 acres of arable land. Potential impacts to high-value farmland within the proposed micrositing corridor, which is not used for irrigated agriculture but for the creation of big game habitat for hunting. The proposed facility would result in approximately 10 square feet of impacts to high-value farmland, which the Department recommends be considered negligible. The applicant commits to recording Farm-Forest Management Easements with each landowner with property within the proposed site boundary (see recommended Land Use Condition 4), as required per WCLU DO Section 3.218.

Potential operational impacts from the proposed solar facility include increased fire risk, both to the proposed facility and from the proposed facility. As presented in Attachment N, draft Operational Fire Protection and Emergency Response Plan, the applicant commits to preventing fire risk within the fenced solar facility area through ongoing vegetation management, agreement and coordination with local fire districts to ensure 24-hr, 7-day week fire response, worker training requirements, and maintenance of onsite fire protection and response equipment.

Outside of the potential impacts to cultivated agriculture within the proposed micrositing corridor, based on the short-term construction impacts and limited activities associated with O&M of a solar facility, the Department recommends that the Council conclude that the proposed facility would not create unnecessary negative impacts on agricultural operations conducted on any portion of the subject property not occupied by facility components, and therefore would satisfy the requirements under OAR 660-033-0130(38)(h)(A).

OAR 660-033-0130(38)(h)(B) Unnecessary Soil Erosion or Loss

OAR 660-033-0130(38)(h)(B) requires the applicant to demonstrate that the proposed facility would not “result in unnecessary soil erosion or loss that could limit agricultural productivity on the subject property” and states that the “provision may be satisfied by submittal and county approval of a soil and erosion control plan prepared by an adequately qualified individual, showing how unnecessary soil erosion will be avoided or remedied.”

As presented in Section IV.D. Soil Protection, the applicant represents that a DEQ-issued NPDES 1200-C permit would be required during proposed facility construction (see recommended Soil Protection Condition 1). The NPDES 1200-C permit requires finalization of an Erosion Sediment Control Plan (ESCP), including engineering drawings, and best management practices to minimize soil erosion and loss to be implemented during facility construction and operation. The draft ESCP as Attachment D of this order.

Based on compliance with the NPDES 1200-C, as required under recommended Soil Protection Condition 1, the Department recommends that the Council conclude that the proposed facility would not result in unnecessary soil erosion or loss that could limit agricultural productivity, and therefore would satisfy the requirements under OAR 660-033-0130(38)(h)(B).

OAR 660-033-0130(38)(h)(C) Unnecessary Soil Compaction

OAR 660-033-0130(38)(h)(C) requires the applicant to demonstrate that the proposed facility would not “result in unnecessary soil compaction that reduces the productivity of soil for crop production.” The applicant asserts that construction of the proposed solar facility would not result unnecessary soil compaction because grading would be limited to roads and areas within the perimeter fenceline. In ASC Exhibit P, the applicant proposes to adhere to the requirements of a Revegetation Plan, as provided in Attachment I of this order and recommended as a condition (recommended Fish and Wildlife Habitat Condition 1). The recommended condition includes a requirement that, based on the applicant’s representation, soil preparation methods for revegetation areas would include deep soil decomposition, unless otherwise agreed to by the underlying landowner.

Based on the limited potential for unnecessary soil compaction during construction and the applicant’s representation to complete deep soil decomposition during revegetation activities, and compliance with the requirements of a finalized Revegetation Plan, the Department recommends that the Council conclude that the proposed facility would not result in unnecessary soil compaction and would satisfy the requirements under OAR 660-033-0130(38)(h)(C).

OAR 660-033-0130(38)(h)(D) Unnecessary Spread of Noxious Weeds

OAR 660-033-0130(38)(h)(D) requires the applicant to demonstrate that the proposed facility would not result in the “unabated introduction or spread of noxious weeds and other undesirable weed species.” Control of noxious weeds is a priority and required during all phases of facility construction and operation. As presented in Attachment K of this order, the applicant commits to implementing the requirements of a Noxious Weed Control Plan, which the Department recommends be imposed as a condition (recommended Fish and Wildlife Condition 2).
2. The draft plan was reviewed by the Wasco County Weed Control Supervisor, as verified by the Department on January 2, 2020. Based on compliance with the Department’s recommended condition, the applicant would be required to finalize the draft plan, prior to construction, in consultation with the Department and Wasco County Weed Control Department. 

Based upon compliance with recommended Fish and Wildlife Condition 2, the Department recommends that the Council conclude that the proposed solar facility would not result in unabated introduction or spread of noxious weeds or other undesirable weed species and would satisfy the requirements under OAR 660-033-0130(38)(f)(D). 

(E) Except for electrical cable collection systems connecting the photovoltaic solar generation facility to a transmission line, the project is not located on those high-value farmland soils listed in OAR 660-033-0020(8)(e); 

OAR 660-033-0130(38)(h)(E) requires that the applicant demonstrate that, with the exception of grid interconnection electrical collection systems, the proposed facility would not be located on high-value farmland soils. As defined in OAR 660-033-0020(8)(a), high-value soils are defined as irrigated and classified prime, unique, Class I or II soils; or, not irrigated and classified prime, unique, Class I or Class II soils. 

As presented in ASC Exhibit K, Table K.2 Summary of Soil Classifications., the Natural Resource Conservation Service (NRCS) soil classification for soils within the proposed micrositing corridor include Class III and VII soils, which as described above, would not be considered high-value soil. Therefore, because high-value farmland soils are not located within the proposed micrositing corridor and therefore would not be impacted by the proposed solar facility, the Department recommends Council find that the proposed solar facility would satisfy OAR 660-033-0130(38)(h)(E). 

(F) The project is not located on those high-value farmland soils listed in OAR 660-033-0020(8)(e) or arable soils unless it can be demonstrated that: 

(i) non-high-value farmland soils are not available on the subject tract; 

(ii) siting the project on non-high-value farmland soils present on the subject tract would significantly reduce the project’s ability to operate successfully; or 

(iii) the proposed site is better suited to allow continuation of an existing commercial farm or ranching operation on the subject tract than other possible sites also located on the subject tract, including those comprised of non-high value farmland soils; and 

OAR 660-033-0130(38)(h)(F) requires the applicant to demonstrate that the proposed solar facility could not be located on high-value farmland soils or arable soils unless: 1) non-high-value farmland soils are not available on the subject tract; 2) siting the project on non-high-value farmland soils, if present, would significantly impact the project’s ability to operate; or 3) the site is better suited than other possible sites because it would allow continued operation of existing farmland. 

Based on the evaluation presented in ASC Exhibit K, the proposed solar facility would not be located on high-value farmland soils, as defined in OAR 660-033-0020(8)(e); therefore, OAR 660-033-0130(38)(h)(F) does not apply and, instead, OAR 660-033-010(38)(i) applies, as evaluated below. 

(G) A study area consisting of lands zoned for exclusive farm use located within one mile measured from the center of the proposed project shall be established and: 

(i) if fewer than 48 acres of photovoltaic solar power generation facilities have been constructed or received land use approvals and obtained building permits within the study area, no further action is necessary. 

(ii) when at least 48 acres of photovoltaic solar power generation facilities have been constructed or received land use approvals and obtained building permits, either as a single project or as multiple facilities within the study area, the local government or its designate must find that the photovoltaic solar power generation facility will not materially alter the stability of the overall land use pattern of the area. The stability of the land use pattern will be materially altered if the overall effect of existing and potential photovoltaic solar power generation facilities will make it more difficult for the existing farms and ranches in the area to continue operation due to diminished opportunities to expand, purchase or lease farmland, acquire water rights, or diminish the number of tracts or acreage in farm use in a manner that will destabilize the overall character of the study area. 

OAR 660-033-0130(38)(h)(G) requires an evaluation of photovoltaic solar power generation facility development within 1-mile of the proposed facility site. Based on review of aerial imagery and multiple site visits in 2019/2020, the Department confirms that there are fewer than 48 acres of other photovoltaic solar power generation facilities within 1-mile of the proposed facility site. Therefore, no further action is necessary. 

(i) For arable lands, a photovoltaic solar power generation facility shall not use, occupy, or cover more than 20 acres. The governing body or its designate must find that the
The following criteria are satisfied in order to approve a photovoltaic solar power generation facility on arable land:

(A) The project is not located on those high-value farmland soils listed in OAR 660-033-0020(8)(e):

i. Nonarable soils are not available on the subject tract; (ii) siting the project on nonarable soils present on the subject tract would significantly reduce the project’s ability to operate successfully; or

ii. The proposed site is better suited to allow continuation of an existing commercial form or ranching operation on the subject tract than other possible sites located also on the subject tract, including those comprised of nonarable soils;

(C) No more than 12 acres of the project will be sited on high-value farmland soils described at ORS 195.300(10);

OAR 660-033-0130(38)(i)(A) restricts a photovoltaic solar power generation facility from occupying more than 20 acres of high-value farmland and requires the following criteria to be met: 1) with the exception of a grid interconnecting electrical collection line, facility would not be located on high-value farmland soils; 2) facility is not located on high-value farmland soils or arable soils unless i) nonarable soils are not available on the subject tract; ii) siting facility on nonarable soils on subject tract would significantly increase cost of project operability; or iii) proposed site is better suited to provide continuation of farming on subject tract; and iii) no more than 12 acres of high-value farmland soils would be precluded by the project.

As described in ASC Exhibit K, the proposed microtasting corridor contains less than 10.8 acres of high-value farmland under the ORS 195.300(10)(c)(A) farmland definition (i.e. within the place of use for a water permit). Based on NRCS soil classification, there are no high-value soils present within the proposed microtasting corridor. However, the proposed solar facility would use, occupy or cover more than 20 acres of arable land and therefore would not satisfy OAR 660-033-0130(38)(i) and would require a Goal 3 exception.

ASC Exhibit K Figures K-4 represent arable and non-arable lands within the subject tracts within the analysis area. The applicant describes that most of the non-arable soils within the analysis area are located either on slopes that are north facing, over 15 percent or within a drainage, making them unsuitable for construction and operation of a photovoltaic solar power generation facility. The applicant asserts that, based on industry standard, slopes above 15 percent would require extensive grading to allow for the construction of a photovoltaic solar power generation facility and are recommended be avoided for siting. Extensive amounts of cut and fill would significantly increase construction costs and could lead to greater impacts to soil erosion and sediment loss.

Based on the representations of engineering and technical constraints associated with siting facility components on non-arable lands, as summarized above, the Department recommends Council find that the proposed solar facility would satisfy OAR 660-033-0130(38)(i)(A)-(C).

(D) A study area consisting of lands zoned for exclusive farm use located within one mile measured from the center of the proposed project shall be established and:

i. If fewer than 80 acres of photovoltaic solar power generation facilities have been constructed or received land use approvals and obtained building permits within the study area no further action is necessary.

ii. When at least 80 acres of photovoltaic solar power generation facilities have been constructed or received land use approvals and obtained building permits either as a single project or as multiple facilities, within the study area the local government or its designate must find that the photovoltaic solar power generation facility will not materially alter the stability of the overall land use pattern of the area. The stability of the land use pattern will be materially altered if the overall effect of existing and potential photovoltaic solar power generation facilities make it more difficult for the existing farms and ranches in the area to continue operation due to diminished opportunities to expand, purchase or lease farmland, acquire water rights or diminish the number of tracts or acreage in farm use in a manner that will destabilize the overall character of the study area; and

OAR 660-033-0130(38)(i)(D) requires an evaluation of photovoltaic solar power generation facility development within 1-mile of the proposed project site. Based on review of aerial imagery and multiple site visits in 2019/2020, the Department confirms that there are fewer than 80 acres of other photovoltaic solar power generation facilities within 1-mile of the proposed facility site. Therefore, no further action is necessary.

(E) The requirements of OAR 660-033-0130(38)(h)(A), (B), (C) and (D) are satisfied.

OAR 660-033-0130(38)(i)(E) requires Council to find that OAR 660-033-0130(38)(h)(A)-(D) are satisfied. As presented in this section, the Department recommends Council find that the proposed solar facility would satisfy the requirements of OAR 660-033-0130(38)(h)(A)-(D).

(k) An exception to the acreage and soil thresholds in subsections (q), (n), (i), (l) and (j) of this section may be taken pursuant to ORS 197.732 and OAR chapter 660, division 4.

OAR 660-033-0130(38)(k) establishes that, for projects that would be sited on 20 acres or more of high-value farmland, an exception is required pursuant to ORS 197.732 and OAR Chapter 660, division 4. The proposed solar facility would use, occupy or cover more than 20 acres of high-value farmland from agricultural use. The Department’s assessment of the applicant’s Goal 3 exception request is evaluated in Section III.E.3, Goal 3 Exception of this order below and recommends that the Council find that an exception to Goal 3 is justified.

Based on the applicant’s application for a site certificate, the Department recommends that the Council find that an exception to Goal 3 is justified.
(i) The county governing body or its designee shall require as a condition of approval for a photovoltaic solar power generation facility, that the project owner sign and record in the deed records for the county a document binding the project owner and the project owner’s successors in interest, prohibiting them from pursuing a claim for relief or cause of action alleging injury from farming or forest practices as defined in ORS 30.930(2) and (4).

ORS 469.504(2) requires a determination by the Council that an exception to Goal 3 is warranted under the proposed requirements under OAR 660-033-0130(38)(b) unless a goal exception is taken. Pursuant to ORS 469.504(1)(b)(B), non-compliance with a statewide planning goal requires a determination by the Council that an exception to Goal 3 is warranted under ORS 469.504(2) and the implementing rule at OAR 345-022-0030(X).

ORS 469.504(2) expressly provides that the Council makes a goal exception using the review requirements in ORS 469.504(2)(a)(C) including: (A) notwithstanding the requirements in ORS 197.732 * * *(i) the state policy embodied in Goal 3 is the preservation and maintenance of agricultural forest practices as defined in ORS 30.930(2) and (4). The land subject to the exception is physically developed to the extent that the land is no longer available for uses allowed by the applicable goal; (a) The proposed facility is compatible with other adjacent uses or will be anticipated as a result of the proposed facility have been identified and adverse impacts will be mitigated in accordance with rules of the Council applicable to the siting of the proposed facility; and (c) The proposed facility is compatible with other adjacent uses or will be made compatible through measures designed to reduce adverse impacts.

The provisions of ORS 345-022-0030(4)(a) and (b) are not applicable to the proposed facility. In ASC Exhibit K, the applicant provides an assessment as to why a goal exception, under ORS 345-022-0030(4) is appropriate. The County will implement the Goal 3 exception contained in the EFC final order and site certificate pursuant to ORS 469.504(7).

Reasons Supporting an Exception

Under ORS 345-022-0030(4)(c) and ORS 469.504(2)(c)(A), in order for the Council to determine whether to grant an exception to a statewide planning goal, the applicant must provide reasons justifying why the state policy embodied in the applicable goal should not apply. The state policy embodied in Goal 3 is the preservation and maintenance of agricultural forest practices as defined in ORS 30.930(2) and (4). The land subject to the exception is physically developed to the extent that the land is no longer available for uses allowed by the applicable goal; (a) The proposed facility is compatible with other adjacent uses or will be anticipated as a result of the proposed facility have been identified and adverse impacts will be mitigated in accordance with rules of the Council applicable to the siting of the proposed facility; and (c) The proposed facility is compatible with other adjacent uses or will be made compatible through measures designed to reduce adverse impacts.

The provisions of ORS 345-022-0030(4)(a) and (b) are not applicable to the proposed facility. In ASC Exhibit K, the applicant provides an assessment as to why a goal exception, under ORS 345-022-0030(4) is appropriate. The County will implement the Goal 3 exception contained in the EFC final order and site certificate pursuant to ORS 469.504(7).
Approximately 10.8 acres are high and therefore cultivation proposed facility components within non-arable land, and based on NRCS soil classification contain not used for irrigation purposes.

The proposed micrositing corridor contains 4,160 acres; hosting a barn or crop processing equipment areas knowledge, are otherwise used to supp have the potential to (3,654 acres), which if approved, would authorize placement of facility components or potential impacts as described above, an exception is required pursuant to OAR 660-033-0130(38)(d) for potential impacts to agricultural lands exceeding the 20 acre arable land threshold. As noted throughout this order, the applicant seeks Council approval of a 4,160 acre micrositing corridor, which if approved, would authorize placement of facility components or potential impacts anywhere within. Therefore, this arable lands impact assessment (percentage of impacts) is based on agricultural cultivation on arable lands within the entirety of the micrositing corridor (3,654 acres), as lands deemed unsuitable for cultivation (non-arable, 495 acres) would not have the potential to be impacted and are not lands that, based on the Department’s knowledge, are otherwise used to support farming operations on the 3,654 acres such as by hosting a barn or crop processing equipment areas.

The proposed micrositing corridor contains 4,160 acres; 495 acres (12 percent) are NRCS Class VII non-arable soils and are considered non-arable, or not suitable for cultivation. Placement of proposed facility components within non-arable land would not have the ability to impact cultivation and are not otherwise used to support farming operations on the remaining lands, and therefore these 495 acres are excluded from the impact assessment (to cultivated lands). Approximately 10.8 acres are high-value farmland, pursuant to ORS 195.300(10)(c)(A), due to an existing water right used to provide wildlife habitat for big game, where the water right is not used for irrigation purposes. The amount of high-value farmland that could be impacted is below LCDC’s 12 acre threshold for requiring a goal exception; therefore, this acreage is not included in the arable lands impact assessment (percentage of impacts), and a Goal 3 exception would not be required based solely on potential impacts to high-value farmland.

Approximately 3,654 acres (88 percent) within the micrositing corridor are NRCS Class III arable soils and therefore considered arable land. While the land within the micrositing corridor is predominately arable land, and based on NRCS soil classification contains soils suitable for cultivation, less than 324 acres (9 percent) are used for non-irrigated cultivation of wheat and other row crops. The remaining 3,330 acres is non-irrigated, non-cultivated and used as either rangeland or is currently or was formerly enrolled in the United States Department of Agriculture’s Conservation Reserve Program (CRP), where much of the land is no longer eligible for CRP funding due to its 10-15 year term per parcel. Lands enrolled in CRP are not used for agriculture but are placed in conservation to recover from agricultural or other sensitive erosion, compaction) impacts. The applicant asserts that cultivation on the 3,330 acres of non-cultivated, non-irrigated lands within the proposed micrositing corridor is not economically viable, nor on the cultivated areas due to limited annual average rainfall ranging between 1 and 7 inches within the area, and lower than average winter wheat production capacity (less than 60 bushels an acre). In summary, the applicant represents that potential impacts to cultivated agriculture within the micrositing corridor would be minimal at 9 percent of the total arable land to be potentially impacted, and would be more than offset through lease payments that could be used to supplement income necessary to maintain agricultural operations on other lands owned by underlying landowners.

The Department agrees with the applicant’s reasoning as presented in this section. The land, while classified as “arable” based on the soil classification, is not viable for productive crop cultivation due to the lack of irrigation water or other water source. The Department recommends that Council conclude that due to minimal impacts to agriculture, particularly cultivated agriculture, as well as the low value of rangeland for grazing purposes, and other findings presented here, this “reason” justifies a Goal 3 exception.

### Local Economic Benefits

The applicant requests that Council consider the local economic benefits from construction and operation of the proposed facility as a reason for granting an exception to the state policy embodied in Goal 3.

As identified by the applicant, local economic benefits from proposed facility construction and operation would likely include lease payments to underlying landowners, additional landowner compensation for back and future taxes, job creation, and potentially community service fees paid to Wacoo County through a Strategic Investment Program (SIP) agreement. The applicant represents that lease payments to landowners of the area where proposed facility components would be placed would provide a net benefit to landowner incomes, replacing lost CRP income, and would provide a stable and predictable source of income that would supplement farm/ranch revenues and help ensure these properties could stay within current ownership rather than being sold to corporations or subdivided. In addition, the applicant describes providing landowners additional compensation for any back and future taxes necessary for any land disqualified from CRP due to the proposed facility’s use of the land.

Rural economic development would benefit from proposed facility construction based on potentially available jobs, where the applicant estimates that up to 120 local construction jobs would be available for multiple 9 to 12 month phases. Rural economic development would also benefit from tax revenue generated during construction activities from the use of local goods and services (housing, food, gas, etc.), as well as from the facility’s payment of property taxes or through fees paid directly to the county under a program such as the Rural Renewable Energy Development incentive program or the Strategic Investment Program where fees are.

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paid directly to the county in lieu of property taxes. The income generated through either the
proposed facility’s property tax revenue or the proposed facility’s service fee payments could
fund infrastructure improvements, such as rural fire fighting engines and equipment, that
would benefit Wasco County’s agricultural and forestry-based economy.

The Department agrees that proposed facility construction and operation would benefit the
local economy as presented in the findings here. The Department recommends the Council
conclude that this argument is a relevant “reason” justifying a Goal 3 exception.

Proposed Facility Components are Locational Dependent

The Department recommends Council consider that the proposed facility is locationally
dependent as a reason for granting an exception to the state policy embodied in Goal 3. In the
ASC, the applicant describes important geographic characteristics of the proposed facility site
and the grid interconnection location at BPA’s existing Maupin Substation, which are primary
drivers for the location of the proposed facility site – resulting in a reason considering the
locational dependence of proposed facility components within the proposed micrositing
corridor.

In its evaluation of ORS 215.274(B) for the proposed 230 kV transmission line, the applicant
describes that the site of the proposed solar facility provides unique geographic features
including slopes below 15 percent and sufficient space away from objects or landforms that
would cause shading. In ASC Exhibit B, the applicant describes that an agreement with BPA
would be executed for interconnection to the northwest powergrid via BPA’s existing Maupin
Substation. Based on the proximity of the proposed facility site to BPA’s existing Maupin
Substation, and representations that an executed interconnection agreement with BPA would
be obtained following receipt of an approved site certificate, the Department recommends
Council conclude that this argument is a relevant reason justifying a Goal 3 exception.

Reasons Recommended Not be Considered by Council for a Goal 3 Exception

In addition to the reasons described above, the applicant requests Council consideration of
reasons which the Department recommends not be considered, as further described below.
The applicant asserts that it does not seek to permanently remove land from agricultural
production, and that the land, which per lease terms, would be returned to agricultural
purposes following retirement and restoration. The Department agrees that the site could be
returned to agricultural purposes after facility retirement; however, the Department does not
consider this argument relevant to “reasons supporting an exception.” The site, as requested,
would preclude agricultural use for 40+ years, at least. While effects of the land removal may
not be “permanent” in a long time scale, such effects nonetheless sufficiently disturb land for an
extended period of time. The Department therefore recommends that the Council conclude
that the mere fact that the land may be returned for agricultural use, after its projected

retirement after 40 years or more, is not a sufficient “reason” justifying a Goal 3 exception for
the proposed facility.

The applicant also asserts that the availability of reliable renewable energy relates to the ability
to recruit and retain energy-dependent businesses, which may maintain renewable energy
procurement policies. The applicant has not provided evidence of any specific companies that
are considering to expand, or move business, because of renewable energy procurement
policies. Therefore, the Department considers this argument to be attenuated and lacking
specifics and recommends Council conclude that this argument is not a sufficient reason
justifying a Goal 3 exception.

The applicant asserts that the proposed facility would further public and private policies,
including but not limited to Oregon’s Renewable Portfolio Standard (RPS), which requires
utilities to provide 50 percent of its electricity from renewable sources by 2040. The
Department agrees that energy generated by the proposed facility could apply towards the
State’s RPS requirements if RECs are generated and purchased by in-state utilities. However,
there is no requirement in the State RPS requirements that renewable energy be procured from
Oregon-based resources, nor direct facility development on agricultural lands, the Department
does not consider abstract consistency with the State’s RPS standard to be a sufficient “reason”
justifying a Goal 3 exception, specifically. Additionally, the applicant has not provided a power
purchase agreement or other documentation that would demonstrate that the proposed
facility would provide power to an Oregon utility in support of its RPS requirements. Therefore,
the Department recommends that Council conclude that although the development of the
proposed facility as a renewable energy source would further and advance the State’s
renewable energy resources policy, this is not considered a sufficient reason supporting or
justifying a Goal 3 exception for the proposed facility.

Finally, the applicant asserts that the proposed facility would further Statewide Planning Goal
13. Although Goal 13 requires consideration of renewable energy in planning efforts, it does
not call for development of new renewable energy facilities or address where such facilities
should be located. Goal 13 is thus consistent with Goal 3 and the longstanding Agricultural Land
Use Policy statement in ORS 215.243 as it does not direct renewable energy to be sited in
exclusive farm use zones. Therefore, the Department recommends that Council not consider
the applicant’s assertion of Goal 13 consistency as a sufficient reason supporting or justifying a
Goal 3 exception for the proposed facility.

The applicant asserts that the proposed facility would be consistent with Wasco County Goal
13. Specifically, Policies 1, 2, and 6.

Policy 1: The County will work with appropriate State and Federal agencies to identify
and protect, and if feasible, develop potential energy resources, especially renewable
energy resources.
Policy 2: Reduce the consumption of non-renewable sources of energy whenever possible.
A. Conversion of energy sources from non-renewable to renewable sources shall be encouraged.
B. The allocation of land and uses permitted on the land should seek to minimize the depletion of non-renewable sources of energy.

Policy 6
Use of renewable energy shall be encouraged.

These three policies broadly direct the county to encourage the development of renewable energy resources. As the proposed facility is a solar generating facility, significant environmental, economic, social and energy consequences:

Under OAR 345-022-0030(4)(c)(B) and ORS 469.504(2)(c)(B), in order for the Council to determine whether to grant an exception to a statewide planning goal, the applicant must show that "the significant environmental, economic, social and energy consequences" of the proposed facility have been identified and mitigated in accordance with Council standards.

The proposed facility must satisfy the requirements of all applicable EFSC standards, rules and statutes. Applicable environmental EFSC standards include: General Standard of Review; Soil Protection standard; Protected Areas standard; Recreation Standard; Scenic Resources standard; Fish and Wildlife Habitat standard; and the Threatened and Endangered Species standard. As presented in this order, the Department recommends that the Council find that the proposed facility has been designed to avoid and where necessary, to mitigate impacts to soils, wetlands, fish and wildlife habitats, and threatened and endangered species through recommended conditions of approval.

Based on the recommended findings of fact, conclusions of law, and conditions of approval presented within this order, the Department recommends that Council find that the proposed facility, including mitigation, would not cause significant adverse environmental consequences or impacts.

Economic Consequences
Economic consequences of a proposed facility could include potential impacts to providers of public services, as well as benefits from local job creation, increased tax revenue from property taxes received from the proposed facility site and from consumption of local goods and services from new or temporary residents associated with the proposed facility, and supplemental income to property owners through lease payments or other compensatory payments. As presented in ASC Exhibit U and evaluated in Section IV.M. Public Services of this order, based upon compliance with recommended conditions, the Department recommends Council find that the proposed facility would not have a significant impact on providers of public or private services. As evaluated above, under the local Economic Benefits reason, construction and operation of the proposed facility would provide economic benefits through multiple sources. Based on these factors as evaluated under the applicant’s public services impact assessment, recommended conditions of approval, and local economic benefits realized from proposed facility construction and operation, the Department recommends that the Council conclude that the proposed facility represents a net benefit compared to the proposed site’s existing uses and economic consequences.

Social Consequences
Social consequences of a proposed facility could include impacts from proposed facility visibility, noise, traffic or demand on providers of public services (health care, education, housing, water supply, waste disposal, transportation, fire and safety). As demonstrated in the applicable sections of this order, the Department recommends Council find that impacts to important or significant scenic resources, protected areas, and recreational opportunities would not result in significant adverse impacts and would comply with the appropriate Council standards. The Department addresses potential adverse impacts to public services in Section IV.M. Public Services; and impacts to cultural resources in Section IV.K. Historic, Cultural and Archeological Resources. Based on the Department’s recommended findings of fact and conclusions of law, and recommended conditions of compliance, as presented in the proposed order under the Council’s Scenic Resources standard; Historic, Cultural and Archeological standard; Public Services standard; and Recreation standard, the Department recommends Council conclude that the proposed facility would not cause significant adverse social consequences.

Energy Consequences
Energy consequences of a proposed facility could include the amount of energy a proposed facility would require, the source of energy, and whether the proposed facility is consistent with state and local energy policies. The proposed facility would provide a renewable source of energy for sale to the public. In addition, the proposed facility, as a renewable energy source, would be consistent with Oregon's Climate Plan, which establishes goals to reduce greenhouse gas emission levels to at least 45 percent below 1990 emissions levels by 2035 and at least 80 percent below 1990 emissions levels by 2050. As a renewable energy source, the proposed facility would not rely upon other energy generation sources, and with 100 MW of proposed battery storage, would provide a net benefit in renewable energy sources. Based upon the above analysis, the Department recommends the Council find that the proposed facility would have beneficial energy consequences.

Compatibility of Adjacent Uses

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Under OAR 345-022-0030(4)(c)(C) and ORS 469.5042(c)(C), in order for the Council to
determine whether to grant an exception to a statewide planning goal, the applicant must
show that the proposed facility is compatible with other adjacent land uses or will be made
compatible through mitigation measures. As explained in ASC Exhibit K, adjacent land uses
include agricultural ranching with some mixed residential/agricultural uses. Adjacent land use
zones within the 0.5-mile analysis area are exclusively EFU-zoned land.

For adjacent and nearby farmland, as described above [under the ORS 215.274 analysis], the
Department recommends that the Council conclude that the proposed facility would not cause
a significant change to accepted farm practices or significantly increase the cost of accepted
farm practices within the surrounding area. Moreover, the economic benefits of the proposed
facility would more than offset any potential impacts to arable land and cultivated agriculture.
Potential impacts to adjacent farm practices would be limited to short-term, temporary
construction impacts associated with dust, construction-related traffic, and temporary
increases in local population and resource demand, which would be minimized through
compliance with recommended conditions. Therefore, the Department recommends that
Council conclude that the proposed facility would be compatible with other adjacent land uses
and land use zones and that the proposed facility would meet the standard under OAR 345-
022-0030(4)(c)(C).

Goal 3 Conclusion of Law

Based on the foregoing findings and evidence in the record, the Department recommends that
Council grant a Goal 3 exception for the 3,654 acres of arable land within the proposed
micrositing corridor that could be occupied by proposed facility components, subject to
compliance with the recommended site certificate conditions.

Wasco County Comprehensive Plan Amendment to Reflect Goal Exception

In ASC Exhibit K, the applicant requests Council impose a condition requiring that, prior to
construction of the proposed facility, the applicant submit a proper application and filing fees
to the county for a comprehensive plan amendment to reflect the exception taken to Goal 3
through the ASC approval process. The applicant suggests that the request for a comprehensive
plan amendment should be completed by the county without hearing or other procedure
because it is a land use decision pursuant to OAR 345.0000(3)(d) and 0130(2), and should be
considered like a permit governed by a site certificate, where the county's procedural
requirement is superseded by procedural requirements of the Council through the
comprehensive state-level permitting process.

As provided by Wasco County Planning Department in a comment on the ASC, an exception in a
gal on farmers in a statewide permit is a provision of a comprehensive plan pursuant to OAR
660.015(3)(B) and ORS 197.733, therefore, if the Council takes an exception based upon an
applicant's request, the applicant is obligated to request that the exception taken by the
Council be reflected in the county's comprehensive plan. Pursuant to OAR 469.5047, the

County shall be obligated to update or amend its comprehensive plan to reflect the decision of
Council on the facility Goal 3 exception before on or before its next periodic review. The county
must do so consistent with the findings and conditions of the site certificate, and the county
may impose additional substantive review criteria or process requirements when
incorporating the Council's Goal 3 exception decision into the comprehensive plan. The
applicant is not obligated to provide additional information to the county except the proper
form of goal exception application and filing fee; no evidence or analysis under ORS 197.732
and the implementing LCCO goal exception regulations is required. Based on the findings and
approvals of the Council, and therefore, while the Department does not consider the site
certificate procedural requirements to supersede the county's comprehensive plan amendment
process, it does consider the county to be precluded from applying any substantive review or
make findings of fact, related to the exception taken by Council during its comprehensive plan
amendment process. Based on this analysis and reasoning, the Department recommends
Council impose the following condition:

**Recommended Land Use Condition 12:** Prior to construction of the facility,
a. Prior to construction of the facility, the certificate holder shall submit a Goal Exception
   Application form, complete Comprehensive Plan Amendment Request Application to
   Wasco County Planning Department and necessary fees to amend the Wasco County
   Comprehensive Plan (WCCP) to reflect the Energy Facility Siting Council's (Council)
   findings and approval of the exception taken to the statewide policy embodied in Goal 3
due to the solar facility's use, occupation or coverage of more than 20 acres of arable
   land. [WCLUDO Section 3.215(M); OAR 660-033-0130(3)]

b. The WCCP amendment requested by the certificate holder under (a) of this condition
   shall be subject to the county's administrative procedures in WCCP Chapter 11(j) but
   pursuant to OAR 469.5047, the county shall be required to amend the WCCP to reflect
   the goal exception taken.

c. The county's WCCP Chapter 11(j) administrative procedures do not represent a permit
   or land use decision or approval necessary for the siting or approval of the facility and
   cannot result in changes to the findings and approval of the goal exception taken by
   Council, or impact the certificate holder's ability to comply with the terms and
   conditions of the site certificate or any local or state permit governed by the site
   certificate.

d. The certificate holder shall notify the Department once the Wasco County Board of
   Commissioners amends the WCCP
   [PRE-LU-07]

Conclusions of Law

Based on the foregoing recommended findings and the evidence in the record, and subject to
compliance with the recommended site certificate conditions, the Department recommends
the Council finds an exception to Goal 3 is justified under OAR 345-022-0030(4)(c) and ORS
469.5042(c), and that therefore the Department recommends the Council find that the
proposed facility would comply with the applicable statewide planning goal (Goal 3). As such,
subject to the recommended conditions, the Department recommends Council find that the proposed facility would comply with the Council’s Land Use standard.

IV. Protected Areas: OAR 345-022-0040

(1) Except as provided in sections (2) and (3), the Council shall not issue a site certificate for a proposed facility located in the areas listed below. To issue a site certificate for a proposed facility located outside the areas listed below, the Council must find that, taking into account mitigation, the design, construction and operation of the facility are not likely to result in significant adverse impact to the areas listed below. References in this rule to protected areas designated under federal or state statutes or regulations are to the designations in effect as of May 11, 2007:

(a) National parks, including but not limited to Crater Lake National Park and Fort Clatsop National Memorial;

(b) National monuments, including but not limited to John Day Fossil Beds National Monument, Newberry National Volcanic Monument and Oregon Caves National Monument;

(c) Wilderness areas established pursuant to The Wilderness Act, 16 U.S.C. 1131 et seq. and areas recommended for designation as wilderness areas pursuant to 43 U.S.C. 1782;

(d) National and state wildlife refuges, including but not limited to Ankeny, Bandon Marsh, Baskett Slough, Bear Valley, Cape Meares, Cold Springs, Deer Flat, Hart Mountain, Julia Butler Hansen, Klamath Forest, Lewis and Clark, Lower Klamath, Malheur, McKay Creek, Oregon Islands, Sheldon, Three Arch Rocks, Umatilla, Upper Klamath, and William L. Finley;

(e) National coordination areas, including but not limited to Government Island, Ochoco and Summer Lake;

(f) National and state fish hatcheries, including but not limited to Eagle Creek and Warm Springs;

(g) National recreation and scenic areas, including but not limited to Oregon Dunes National Recreation Area, Hell’s Canyon National Recreation Area, and the Oregon Cascades Recreation Area, and Columbia River Gorge National Scenic Area;

(h) State parks and waysides as listed by the Oregon Department of Parks and Recreation and the Willamette River Greenway;

(i) State natural heritage areas listed in the Oregon Register of Natural Heritage Areas pursuant to ORS 273.581;

(j) State estuarine sanctuaries, including but not limited to South Slough Estuarine Sanctuary, OAR Chapter 142;

(k) Scenic waterways designated pursuant to ORS 390.826, wild or scenic rivers designated pursuant to 16 U.S.C. 1271 et seq., and those waterways and rivers listed as potentials for designation;

(l) Experimental areas established by the Rangeland Resources Program, College of Agriculture, Oregon State University; the Prineville site, the Burns (Squaw Butte) site, the Starkey site and the Union site;

(m) Agricultural experimental stations established by the College of Agriculture, Oregon State University, including but not limited to: Coastal Oregon Marine Experiment Station, Astoria Mid-Columbia Agriculture Research and Extension Center, Hood River Agriculture Research Center, Pendleton Columbia Basin Agriculture Research Center, Mono North Willamette Research and Extension Center, Aurora East Oregon Agriculture Research Center, Union Malheur Experiment Station, Ontario Eastern Oregon Agriculture Research Center, Burns Eastern Oregon Agriculture Research Center, Squaw Butte Central Oregon Experiment Station, Madras Central Oregon Experiment Station, Powell Butte Central Oregon Experiment Station, Redmond Central Station, Corvallis Coastal Oregon Marine Experiment Station, Newport Southern Oregon Experiment Station, Medford Klamath Experiment Station, Klamath Falls;

(n) Research forests established by the College of Forestry, Oregon State University, including but not limited to: Coastal Oregon Marine Experiment Station, Medford Klamath Experiment Station, Klamath Falls;

(o) Research forests established by the College of Forestry, Oregon State University, including but not limited to: Coastal Oregon Marine Experiment Station, Medford Klamath Experiment Station, Klamath Falls;

(p) State wildlife areas and management areas identified in OAR chapter 635, Division 8.

(3) The provisions of section (1) do not apply to transmission lines or natural gas pipelines routed within 500 feet of an existing utility right-of-way containing at least one transmission line with a voltage rating of 115 kilovolts or higher or containing at least one natural gas pipeline of 10 inches or greater diameter that is operated at a pressure of 125 psig.
Findings of Fact

The Protected Areas standard requires the Council to find that, taking into account mitigation, the design, construction and operation of a proposed facility are not likely to result in significant adverse impacts to any protected area as defined by OAR 345-022-0046.\(^1\)\(^2\) As required under OAR 345-021-0010(1), the applicant identifies the protected areas within the analysis area and evaluates the following potential impacts during proposed facility construction and operation: excessive noise, increased traffic, water use, wastewater disposal, visual impacts of facility structures.\(^3\)

The analysis area for protected areas is the area within and extending 20 miles from the proposed site boundary. The applicant addresses protected areas in ASC Exhibit L. The applicant’s assessment of impacts to protected areas also relies on information presented in ASC Exhibit K (Scenic Resources) and ASC Exhibit X (Noise).

As presented in Table 3: Protected Areas within Proposed Facility Analysis Area, and Potential Visibility and Audibility of Proposed Facility (Solar Facility and 230 kV Transmission Line), 13 protected areas were identified by the applicant within the analysis area, where based upon a visual impact assessment, proposed facility components would be visible or partially visible from 7 protected areas, and based upon a statistical noise analysis, audibility of proposed facility operations would not occur at any protected area. Potential impacts from the proposed facility at protected area within the analysis area are evaluated below.

\(^{1,2}\) OAR 345-021-0010(1) defines “significant” as “...having an important consequence, either alone or in combination with other factors, based upon the magnitude and likelihood of the impact on the affected human population or natural resources, or on the importance of the natural resource affected, considering the context of the action or impact, its intensity and the degree to which possible impacts are caused by the proposed action. Nothing in this definition is intended to require a statistical analysis of the magnitude or likelihood of a particular impact.”

\(^{3}\) The proposed facility would not generate any emission plumes and therefore would not result in visual impacts from air emissions. Therefore, visual impacts from air emissions resulting from proposed facility construction or operation, including but not limited to impacts on Class I Areas as described in OAR 340-204-0050, is not applicable and therefore not addressed in this order.

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Table 3: Protected Areas within Proposed Facility Analysis Area, and Potential Visibility and Audibility of Proposed Facility (Solar Facility and 230 kV Transmission Line)

<table>
<thead>
<tr>
<th>Protected Area (OAR Reference)</th>
<th>Distance from Proposed Facility</th>
<th>Proposed 230 kV Transmission Line</th>
<th>Proposed Solar Array</th>
<th>Operational Noise Potentially Audible?</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Distance (miles)</td>
<td>Potentially Visible?</td>
<td>Distance (miles)</td>
<td>Potentially Visible?</td>
</tr>
<tr>
<td>Deschutes River - Federal Wild and Scenic River (OrR 345-022-0043(3)(i))</td>
<td>West</td>
<td>1.9</td>
<td>Yes</td>
<td>8.5</td>
</tr>
<tr>
<td>Oak Spring Fish Hatchery, Oregon Department of Fish and Wildlife (OrR 345-022-0043(3)(ii))</td>
<td>Northwest</td>
<td>2.0</td>
<td>No</td>
<td>9.0</td>
</tr>
<tr>
<td>White Wild and Scenic River (OrR 345-022-0043(3)(i))</td>
<td>Northwest</td>
<td>3.1</td>
<td>Yes</td>
<td>9.7</td>
</tr>
<tr>
<td>White River Wildlife Area (OrR 345-022-0043(3)(ii))</td>
<td>Northwest</td>
<td>3.5</td>
<td>No</td>
<td>10.1</td>
</tr>
<tr>
<td>Tidgh Valley State Natural Area (OrR 345-022-0043(3)(iii))</td>
<td>Northwest</td>
<td>4.0</td>
<td>No</td>
<td>10.7</td>
</tr>
<tr>
<td>White River Wildlife Area (OrR 345-022-0043(3)(i))</td>
<td>Northwest</td>
<td>9.2</td>
<td>Yes</td>
<td>16.2</td>
</tr>
<tr>
<td>Lower White River Wilderness (OrR 345-022-0043(3)(d))</td>
<td>West</td>
<td>15.7</td>
<td>Yes</td>
<td>21.9</td>
</tr>
<tr>
<td>Budget Creek Wilderness (including National Recreation Trail) (OrR 345-022-0043(3)(i))</td>
<td>Northwest</td>
<td>16.8</td>
<td>Yes</td>
<td>23.9</td>
</tr>
<tr>
<td>John Day River - Federal Wild and Scenic Waterway (Waterway John Day River – Federal Wild and Scenic River and Oregon Scenic Waterway)</td>
<td>East</td>
<td>16.8</td>
<td>No</td>
<td>16.2</td>
</tr>
</tbody>
</table>

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### Table 3: Protected Areas within Proposed Facility Analysis Area, and Potential Visibility and Audibility of Proposed Facility

<table>
<thead>
<tr>
<th>Protected Area (OAR Reference)</th>
<th>Distance from Proposed Facility</th>
<th>Proposed 345 kV Transmission Line</th>
<th>Proposed Solar Array</th>
<th>Operational Noise Potentially Visible?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deschutes-Duene S. State Fish Hatchery</td>
<td>18.6 miles</td>
<td>Yes</td>
<td>19.7</td>
<td>Yes</td>
</tr>
<tr>
<td>Mount Hood National Recreation Area</td>
<td>19.6 miles</td>
<td>Yes</td>
<td>20.4</td>
<td>Yes</td>
</tr>
<tr>
<td>Deschutes-Oregon Wld &amp; Scenic River (OAR 345-022-004X(1)(b))</td>
<td>19.6 miles</td>
<td>No</td>
<td>19.7</td>
<td>No</td>
</tr>
<tr>
<td>Columbia River, Wild and Scenic River (OAR 345-022-004X(1)(g))</td>
<td>19.7 miles</td>
<td>No</td>
<td>20.4</td>
<td>No</td>
</tr>
</tbody>
</table>

#### Potential Noise Impacts

1. **The significance of potential noise impacts to identified protected areas is based on the magnitude and likelihood of the impact on the affected human population or natural resources that uses the protected area. The nearest protected area to the proposed site boundary could be potentially impacted by noise generated during proposed facility construction or operation is White River Falls State Park, located approximately 3.5 miles and 10.1 miles northwest from the proposed transmission line and solar array area, respectively.**

2. **Potential noise impacts from proposed facility construction and operation are evaluated below.**

3. **As evaluated in the ASC Exhibit X, construction-related noise impacts are based on equipment sound levels as provided in the 2006 Federal Highway Administration Roadway Construction Noise Model. Proposed facility construction would include site preparation, grading, construction of staging areas and onsite access routes; array foundation installation, conductor installation, and construction of collector substations; solar panel assembly and construction electrical components; inverter pad construction; commissioning of solar array and grid interconnection; installation of transmission structure foundations; erection of support structures; and, conductor stringing.**

4. **As presented in ASC Exhibit X Table X-4, typical construction equipment and predicted sound pressure levels at specific distances would include but is not limited to: bulldozer (88 – 43 dBA at 50 – 5,000 ft), grader (85 – 40 dBA at 50 – 5,000 ft), crane (83 – 38 dBA at 50 – 5,000 ft), and portable generator (84 – 39 dBA at 50 – 5,000 ft). Based on the typical sound pressure levels of equipment that could be used during proposed facility construction of 43 dBA at 5,000 feet (less than 1-mile), where 43 dBA is identified in ASC Exhibit X as equivalent to a quiet rural residential area with no activity, due to attenuation at the nearest protected area that could be impacted by construction-related noise – located at a distance of approximately 3.9 miles – construction-related noise would not be expected to be audible at White River Falls State Park.**

5. **Based on review of the applicant’s construction-related noise impact assessment, as described above, the Department recommends that Council find that proposed facility construction would not result in noise impacts at White River Falls State Park. Because the other protected areas within the analysis area are located at greater distances from the proposed site boundary than there are three protected areas located in closer proximity to the proposed site boundary than White River State Fish.**

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1. **There are three protected areas located in closer proximity to the proposed site boundary than White River State Fish.** However, the Department recommends Council find that the two wild and scenic rivers and one state fish hatchery, based on its purpose and protection under the Council’s Protected Areas standard, would not have the potential to be impacted by noise. The Deschutes River and White River are protected under the Council’s Protected Areas standard due to its wild and scenic river designation, which is based upon the rivers being free of impoundments, with primitive and undeveloped shorelines, which would not have the potential to be impacted by proposed facility noise. Similarly, ODFW’s Oak Springs Fish Hatchery is protected under the Council’s Protected Areas standard due to its designation as a state fish hatchery, with a primary purpose of egg production, incubation and rearing of fish species, which would not have the potential to be impacted by proposed facility noise.
White River Falls State Park, the Department recommends that Council find that there would be no impacts from proposed facility construction noise at the other protected areas.

Operation

Proposed facility components that would generate noise during operations include:

- transformers and inverters associated with the solar arrays, inverters and cooling systems associated with battery storage systems; and corona discharge noise (buzz or crackling during wet conditions) from the 230 kV transmission line. In ASC Exhibit X, the applicant provides a noise analysis inclusive of the operational sources and sound power levels (in A-weighted decibels) for proposed facility components, as listed below:

1. 152 inverters, each at 88 dBA
2. 152 distribution transformers, each at 77 dBA
3. 2 substation transformers at 106 dBA
4. 208 battery storage heating, ventilation and air conditioning units, each at 89 dBA
5. 103 battery storage transformers, each at 77 dBA
6. 230 kV transmission line at 76 to 99 dBA (fair to rainy conditions)
7. 103 battery storage transformers, each at 87 dBA
8. 208 battery storage heating, ventilation and air conditioning units, each at 89 dBA
9. 103 battery storage transformers, each at 77 dBA
10. 230 kV transmission line at 76 to 99 dBA (fair to rainy conditions)

As presented in ASC Exhibit X, statistical noise modeling results indicate that maximum operational noise levels of the proposed facility would range between 20 to 25 dBA within 1-mile of the proposed facility, which would be extremely quiet. At distances greater than 1-mile, due to noise attenuation based on distance, operational noise from the proposed facility would not be audible. Therefore, because the nearest important protected area to proposed facility components would be at a distance of 3.9 miles, the Department recommends Council find that operational noise from the proposed facility would not impact any protected areas within the analysis area.

Traffic Impacts (Construction and Operation)

Proposed facility construction would result in up to 750 average daily trips (ADT) (including worker vehicles, pick-up trucks, material delivery vehicles) on I-84 and Bakeoven Road, 364 ADTs on US 197, 92 ADTs on US 97 (north, part of alternate route), and 46 ADTs on US 97 (south, workforce only). Access to the Deschutes River Federal Wild and Scenic River is provided by Deschutes River Road (also known as Lower Deschutes River Back County Byway), which is fed by US 197 and Bakeoven Road. As presented in ASC Exhibit L, based upon potential construction-related traffic, access to the Deschutes River may be impacted by intermittent short-term traffic delays. The applicant proposes several best management practices, as presented in Attachment M of this order and represented below, in addition to developing a Traffic Management Plan in coordination with the City of Maupin, Wasco County Public Works Department, BLM (Deschutes River managing agency), and ODOT (see recommended Public Services Condition 3).

- Complete consultation with landowners to minimize disruptions to ranching and farming operations due to construction activities such as equipment delivery
- Provide proper road signage and warnings of "Equipment on Road," "Road Closing," or "Road Crossings"
- Implement traffic diversion equipment (such as advance signage and pilot cars) wherever possible when slow or oversize loads are being hauled;
- Employ flag persons to direct traffic when large equipment is exiting or entering public roads to minimize risk of accidents. Flag persons may facilitate two way traffic on one lane by alternately restricting travel directions. This method would not require full lane closures, detours, or reroutes. Flag persons would also monitor traffic on public roadways as necessary so that they are not in conflict with construction vehicles.
- Maintain at least one travel lane at all times so that roadways would not be closed to traffic due to construction vehicles entering or exiting public roads
- Avoid peak traffic times identified through consultation with Wasco County and the City of Maupin by adjusting scheduling of workforce shifts or other methods, such as requiring construction workers to check for congestion prior to leaving for the Facility to consider an alternate route.
- Conduct awareness training for all construction workforce drivers, including appropriate techniques for sharing roads with recreation users (especially cyclists and during peak tourist season mid-June through early September) and proper navigation of tight curves in and near Maupin

Potential traffic impacts during proposed facility construction would be intermittent and temporary, and traffic levels would return to normal following construction.

During operations, the proposed facility would generate an additional 5 to 10 one-way trips on existing local roads. Based on the minimal number of operational trips, the Department agrees with the applicant that the increase would not be likely to have any impact on protected areas, including access points to protected areas.

Based on review of the applicant’s analysis and proposed BMPs, the Department agrees with the applicant’s conclusions and recommends Council find that potential traffic-related impacts during construction and operation of the proposed facility would not likely result in significant adverse impacts to any protected areas.

See Section IV.M, Public Services of this order for further discussion of traffic impacts.
The applicant discusses the proposed facility’s water use in Exhibit O. Generation and management of wastewater during construction and operation are evaluated in Exhibit V and discussed in Section IV.N. Waste Minimization of this order.

Proposed facility construction would use, under high temperatures, dry climactic conditions (i.e., “worst-case conditions”) up to 77 million gallons of water per year for dust suppression, road compaction, concrete foundations, on-site worker drinking and sanitation use. Proposed facility operation would use approximately 1 million gallons of water per year to support O&M building drinking water use and solar panel washing. In ASC Exhibit O, the applicant describes that construction-related water would be obtained from the City of Maupin, through an existing water right permit, or use of an existing or newly constructed well, which would be permitted by a third-party under an Oregon Department of Water Resources-issued limited water use license. Operational water would be obtained by the same sources identified for construction.

In ASC Exhibit O, the applicant provides a letter from the City of Maupin dated May 30, 2019, where Mayor Ewing confirms an ability of the city under its existing water right permit number 518591 to provide water to meet the applicant’s forecasted construction related water demand. The applicant asserts that through its communication with the City of Maupin, that the existing water right 518591 could serve the proposed facility’s construction-related water demand during normal and dry conditions throughout the year. Therefore, the applicant does not anticipate any impact to protected areas from water use during construction or operation of the proposed facility.

As explained in Exhibit L, the applicant indicates that industrial wastewater would not be produced during construction or operation of the proposed facility. Stormwater runoff, which is not considered wastewater but discussed nonetheless, would be managed on site according to the BMPs as described in the NPDES 1200 C/Erosion and Sediment Control Plan (ASC Exhibit I), such that no stormwater would leave the site boundary. During construction, sanitary wastewater would be contained in portable toilets, which the applicant explains would be provided and maintained by a licensed contractor. During operations, sanitary wastes from the O&M buildings would be discharged to a permitted onsite septic system.

Based upon evaluated of the applicant’s proposed water use and non-generation of offsite wastewater, the Department agrees with the applicant’s conclusions and recommends Council find that water use and wastewater disposal during construction and operation of the proposed facility would not result in a significant adverse impact, or any impact, to water quality or quantity within any protected area within the analysis area.

Potential Visual Impacts of Proposed Facility Structures

The applicant’s visual impact assessment methodology includes bare-earth modeling, zone of visual influence (ZVI) analyses. The ZVI analyses were performed using the Spatial Analyst extension of the ESRI ArcGIS software, using a 10-meter digital elevation model to represent the terrain within the analysis area. The ArcGIS software generates lines of sight from the three-dimensional coordinates of the proposed solar facilities (i.e., solar arrays, battery storage system, O&M building, 230 kV transmission line, and overhead 34.5 kV collector line) to points on the terrain surface (factoring a 6-foot offset for viewer height), thereby identifying locations from which the proposed facility components would potentially be visible.17 In ASC Exhibit R, the applicant explains that a bare-earth analysis does not take into account the visibility effects of existing vegetation or buildings, which in practice would block or screen views in some places. In addition, the ZVI model does not account for distance, lighting and atmospheric factors (such as weather) that can diminish visibility under actual field conditions. In other words, the results of the ZVI analysis, which present potential lines of site of proposed facility components, is extremely conservative in identifying potential visibility impacts.

The results of the ZVI analysis indicate that one or more facility components would be visible or partially visible from all 7 protected areas within the analysis area (see Table PA 1, Protected Areas within the Proposed Facility Analysis Area). However, as explained in ASC Exhibit L, the applicant considers visual impacts to be negligible for most protected areas, primarily due to the distance of 9 to 20 miles from the site boundary. Based on the applicant’s ZVI analysis, two protected areas within the analysis area would have limited visibility of the proposed facility, including the Deschutes River Federal Wild and Scenic River and the White Wild and Scenic River. Limited visibility refers to potential visibility of the proposed 230 kV transmission line, only from short river segments at limited locations along the river canyons. Based on review of the applicant’s viewshed analysis, the Department agrees with the applicant’s conclusion and recommends Council find that the proposed facility would not cause a significant, adverse visual impact to the Deschutes Federal Wild and Scenic River or White Wild and Scenic River, or to any other protected area in the analysis area.

Conclusions of Law

Based on the foregoing recommended findings, and subject to compliance with the recommended conditions of approval, the Department recommends the Council conclude that, taking into account mitigation, the design, construction and operation of the proposed facility would not be likely to result in significant adverse impacts to any protected areas, in compliance with the Council’s Protected Area standard.

IV.G. Retirement and Financial Assurance: OAR 345-022-0050

To issue a site certificate, the Council must find that:

1. The site, taking into account mitigation, can be restored adequately to a useful, non-hazardous condition following permanent cessation of construction or operation of the facility.

Findings of Fact

7. The Retirement and Financial Assurance standard requires a finding that the proposed facility site can be restored to a useful, non-hazardous condition at the end of the facility's useful life, should either the applicant (certificate holder) stop construction or should the facility cease to operate. In addition, it requires a demonstration that the applicant can obtain a bond or letter of credit in a form and amount satisfactory to the Council to restore the site to a useful, non-hazardous condition.

Restoration of the Site Following Cessation of Construction or Operation

16. OAR 345-022-0050(1)(a) requires the Council to find that the site of the proposed facility can be restored to a useful non-hazardous condition at the end of the proposed facility’s useful life, or if construction of the proposed facility were to be halted prior to completion. The applicant estimates the proposed facility’s useful life as 40 years, although describes that the proposed facility would likely be upgraded with more efficient equipment over time extending the useful life for much longer than 40 years.

18. As described in ASC Exhibit W, restoring the site to a useful, nonhazardous condition upon cessation of construction or operation (or upon retirement) would involve dismantling solar panels and battery components, and related aboveground equipment (O&M building, transmission and overhead collector lines, transformer/inverter pads, and substation). Solar modules would be separated from anchored steel poles, and directly loaded onto trucks or roll-off containers for off-site disposal. Steel poles would then be removed and recycled. Transformers would be decommissioned (oil would be removed) and hauled and disposed of on-site.

22. Decommissioning of battery storage components would include draining fluids within the flow batteries, and transporting to an off-site facility for recycling. If lithium-ion batteries are selected, disposal would be accomplished in the same manner as routine battery replacement. Self-contained battery components would be removed and disposed of by a qualified vendor. Once the self-contained battery components have been removed, the containers and associated components would be disassembled and transported off-site via truck for disposal or recycling. In both cases, the footprint of the battery storage system would be regraded and seeded for final stabilization. Any unsalvageable material would be disposed of at authorized sites.

26. Concrete pads and foundations (solar panel posts, substation, O&M building and battery storage systems) would be removed to a minimum of 3 feet below grade. Portions of underground electrical and communication cable buried below 3 feet would be left in place. Disturbed areas would be regraded and reseeded with native seed mix, based on landowner consultation. Access roads would then be removed. Access road areas would be restored to surface grade and soil to a condition useful for agriculture or grazing, depending on the use of surrounding lands. Roads also may be left in place based on landowner preference.

The Council’s rules include several mandatory site certificate conditions relating to the obligation of an applicant (certificate holder) to prevent the development of conditions on the site that would preclude restoration of the site and requiring the applicant (certificate holder) to obtain Council approval of a retirement plan in the event that the facility ceases construction or operation, which are as follows:

Recommended Retirement and Financial Assurance Condition 1: The certificate holder shall prevent the development of any conditions on the site that would preclude restoration of the site to a useful, non-hazardous condition to the extent that prevention of such site conditions is within the control of the certificate holder. [Mandatory Condition OAR 345-025-0004(7), GEN-RF-01]

Retirement and Financial Assurance Condition 2: The certificate holder shall retire the facility if the certificate holder permanently ceases construction or operation of the facility. The certificate holder shall retire the facility according to a final retirement plan approved by the Council, as described in OAR 345-027-0110. The certificate holder shall pay the actual cost to restore the site to a useful, nonhazardous condition at the time of retirement, notwithstanding the Council’s approval in the site certificate of an estimated amount required to restore the site. [Mandatory Condition OAR 345-025-0006(9), RET-RF-01]

Retirement and Financial Assurance Condition 3: If the Council finds that the certificate holder has permanently ceased construction or operation of the facility without retiring the facility according to a final retirement plan approved by the Council, as described in OAR 345-027-0110, the Council shall notify the certificate holder and request that the certificate holder submit a proposed final retirement plan to the Department within a reasonable time not to exceed 90 days. If the certificate holder does not submit a proposed final retirement plan by the specified date, the Council may direct the Department to prepare a proposed final retirement plan for the Council’s approval.

Upon the Council’s approval of the final retirement plan, the Council may draw on the bond or letter of credit described in OAR 345-025-0006(8) to restore the site to a useful, nonhazardous condition according to the final retirement plan, in addition to any penalties the Council may impose under OAR Chapter 345, Division 29. If the amount of the bond or letter of credit is insufficient to pay the actual cost of retirement, the certificate holder shall pay any additional cost necessary to restore the site to a useful, nonhazardous condition.

After completion of site restoration, the Council shall issue an order to terminate the site certificate if the Council finds that the facility has been retired according to the approved final retirement plan. [Mandatory Condition OAR 345-025-0006(16), RET-RF-02]
In Section IV.B, Organizational Expertise of this order, the Department recommends that the 1 Council find that the applicant has the organizational expertise to construct, operate, and retire 2 the proposed facility in compliance with that Council standard. In addition, the Department 3 recommends that the Council find that the applicant meets the Council’s Soil Protection, Fish 4 and Wildlife Habitat, and Waste Minimization standards (Sections IV.D, IV.H, and IV.N of this 5 order, respectively). Each of those sections imposes conditions on the applicant that are 6 designed to ensure that construction and operation of the proposed facility would not have 7 adverse impacts on the surrounding land.

Based on compliance with the above-referenced mandatory conditions, and the applicant’s 8 assessment of decommissioning tasks and actions, the Department recommends the Council 9 find that the site of the proposed facility could be restored adequately to a useful, non- 10 hazardous condition following permanent cessation of construction or operation.

Estimated Cost of Site Restoration
11

OAR 345-032-0005(2) requires the Council to find that the applicant has demonstrated a 12 reasonable likelihood of obtaining a bond or letter of credit in a form and amount necessary to 13 restore the site of the proposed facility to a useful non-hazardous condition. A bond or letter of 14 credit provides a site restoration remedy to protect the state of Oregon and its citizens if the 15 applicant (certificate holder) fails to perform its obligation to restore the site. The bond or letter 16 of credit must remain in force until the applicant (certificate holder) has fully restored the site.

OAR 345-032-0010(B) establishes a mandatory condition, included as Retirement and Financial 17 Assurance Condition 4, which ensures compliance with this requirement.

In ASC Exhibit W, the applicant provides a site restoration cost estimate of approximately $20.1 18 million (Q1 2019 dollars). The site restoration cost estimate was prepared by the applicant’s 19 consultant, TetraTech. The scope of work and individual tasks were established using 20 professional experience, in collaboration with the applicant’s engineering staff and contractors.

Production rates were based on professional knowledge and published standards, including 21 review of “RS Means,” a construction cost estimating software. Labor and equipment rates 22 were obtained based on U.S. Department of Labor wage determinations. Typical industry 23 standards were applied for contingency (5 percent), overhead and fee (13 percent).

Based on the decommissioning tasks and actions described above, the level of detail obtained 24 to support the per task cost breakdown (including 50 percent facility engineering and design); 25 the information sources relied upon for hourly rates, equipment and materials (U.S. 26 Department of Labor and RS Means); and, the generally low level of complexity associated with 27 solar facility decommissioning, which are all factors evaluated under the Association for 28 Advancement of Cost Engineering International Cost Estimate Classification System 29 (Classification System), the applicant represents that the cost estimate provided in ASC Exhibit 30 W Attachment W-1, and re-formatted below to present task and unit cost, is a “Class 1” 31 estimate. The applicant then relies upon the Classification System’s guidance to request Council 32 consideration of a lower future development contingency than has historically been applied to 33 the applicant (certificate holder) were to become unable to manage the decommissioning process. The applicant estimates potential expenses incurred by the Department based on fully loaded rates (rate + overhead + benefits) of 2 full-time employees (FTE) ($200,000 per FTE) for 16 months, which includes an anticipated 10 month duration for facility decommissioning and 6 months for preparation and close-out. Based on these assumptions, the applicant seeks Council approval of a contingency equal to approximately $533,000 rather than a contingency of 10 percent applied to the total decommissioning amount, as Council has historically imposed on decommissioning estimates for EFSC facilities.

The Department presents its assessment of this request following Table 4: Proposed Facility 34 Decommissioning Cost Estimate and Unit Costs below.

As presented in ASC Exhibit W, the applicant evaluates labor requirements, equipment needs 35 and duration for each of the tasks and actions identified for site restoration based on the 36 following methods and assumptions:

- Mobilization and demolition costs reflect the anticipated cost to mobilize equipment, facilities and crew to the proposed facility site, assuming the work is performed by local contractors.
- Restoration is estimated on a unit cost basis, priced by task, and follows the progression of work from start to finish.
- Roads would be restored pursuant to the approved retirement plan so that they become a part of the natural surroundings and are no longer recognizable or usable as a road.
- Temporary facilities required during the decommissioning effort have been included in the restoration cost.
- Field management during construction activities has been added to the estimate.
- 5 percent for Home Office and Project Management, and 13 percent for Overhead and Fee were included for contractor overhead fees (approximately $2.74 million total).

Notwithstanding the applicant’s proposed contingencies, which are further evaluated below, 37 the Department recommends Council conclude that the applicant’s consultant, TetraTech, and 38 engineering staff have the experience necessary to adequately and accurately prepare a cost 39 estimate for decommissioning and restoration of the site of the proposed facility. A detailed 40 breakdown of tasks, sub-tasks and costs is presented in ASC Exhibit W Attachment W-1, and is 41 summarized in Table 4: Proposed Facility Decommissioning Cost Estimate and Unit Costs.
Table 4: Applicant’s Proposed Facility Decommissioning Cost Estimate and Unit Costs

<table>
<thead>
<tr>
<th>Task or Action</th>
<th>Quantity</th>
<th>Unit Cost ($)</th>
<th>Unit Estimate ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Mobilization/ Demobilization</td>
<td>1</td>
<td>61,200</td>
<td>Total 61,200</td>
</tr>
<tr>
<td>Site Facilities</td>
<td>1</td>
<td>2,200</td>
<td>Total 2,200</td>
</tr>
<tr>
<td>Crew Mobilization and Site Setup</td>
<td>3</td>
<td>12,065</td>
<td>Day 36,197</td>
</tr>
<tr>
<td>Crew Demobilization and Site Cleanup</td>
<td>2</td>
<td>12,065</td>
<td>Day 24,131</td>
</tr>
<tr>
<td>Home Office (5%/Contractor Overhead and Fee (13%))</td>
<td>1</td>
<td>% of Cost</td>
<td>20,775</td>
</tr>
<tr>
<td>Subtotal =</td>
<td></td>
<td></td>
<td>144,503</td>
</tr>
<tr>
<td>Substation and Transmission Line</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fence Removal</td>
<td>1</td>
<td>1,202</td>
<td>Day 1,202</td>
</tr>
<tr>
<td>Transformer/Oil Removal</td>
<td>12</td>
<td>94,399</td>
<td>Equip. 1,132,728</td>
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<tr>
<td>Remove Control Building</td>
<td>2</td>
<td>2,432</td>
<td>Each 4,864</td>
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<td>Underground Utility and Ground Removal</td>
<td>2</td>
<td>1,202</td>
<td>Day 2,404</td>
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<tr>
<td>Remove Foundations to Subgrade</td>
<td>500</td>
<td>27</td>
<td>Cu. Yd. 13,531</td>
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<tr>
<td>Misc. Materials Disposal</td>
<td>1</td>
<td>1,675</td>
<td>Day 1,675</td>
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<tr>
<td>Restore Yard</td>
<td>4</td>
<td>15,650</td>
<td>Acres 62,603</td>
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<tr>
<td>Conductor Removal</td>
<td>21</td>
<td>33,955</td>
<td>mile 373,513</td>
</tr>
<tr>
<td>Structure Removal</td>
<td>83</td>
<td>4,467</td>
<td>Each 370,806</td>
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<td>Remove Foundations to Subgrade</td>
<td>1</td>
<td>% of Cost</td>
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<td>Home Office (5%/Contractor Overhead and Fee (13%))</td>
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</tr>
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<td>Subtotal =</td>
<td></td>
<td></td>
<td>1,635,418</td>
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<td>103</td>
<td>71</td>
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<td>103</td>
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<td>238</td>
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<td>Inverter/Transformer Removal</td>
<td>152</td>
<td>5,089</td>
<td>Each 773,629</td>
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<td>Inverter/Transformer Disposal</td>
<td>3,496</td>
<td>30</td>
<td>Tsn 104,880</td>
</tr>
<tr>
<td>Remove Foundations to Subgrade</td>
<td>29,184</td>
<td>27</td>
<td>Cu. Yd. 394,341</td>
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<td>Solar Panel Removal</td>
<td>951,900</td>
<td>27</td>
<td>Each 2,650,331</td>
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<td>Solar Panel Tracking</td>
<td>346</td>
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<td>Each 1,363,250</td>
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<td>19,038</td>
<td>30</td>
<td>Tsn 571,140</td>
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<td>25,050</td>
<td>242</td>
<td>Each 6,062,983</td>
</tr>
<tr>
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<td>446</td>
<td>1,375</td>
<td>Each 1,323,250</td>
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<tr>
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<td>10,020</td>
<td>30</td>
<td>Tsn 300,600</td>
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</table>

As presented in ASC Exhibit W, and described above, the applicant seeks Council approval of proposed contingencies which differ from Council’s past practice. Specifically, the applicant seeks Council approval of a project management cost based on an assumed facility decommissioning duration that, with preparation and closeout, would not exceed 16 months, rather than Council’s past practice of applying a 10 percent mark-up to the total decommissioning cost to cover potential ODOE project management and administration costs.

As presented in ASC Exhibit W, and described above, the applicant seeks Council approval of a future development contingency equal to 3 percent of the construction cost.

The applicant also seeks Council approval of a future development contingency equal to 3 percent of the construction cost.
percent, rather than Council's past practice of applying 10 to 20 percent to the total
decommissioning cost.

Department Project Management Cost

In the event that the applicant (certificate holder) were to become unable to fulfill its obligation
to complete facility decommissioning, the Department would require staff time related to the
preparation and approval of a final retirement plan, obtaining legal permission to proceed with
demolition of the facility, legal expenses for protecting the State’s interest, preparing
specification bid documents and contracts for demolition work, managing the bidding process,
negotiations of contracts, and other tasks. In ASC Exhibit W, the applicant explains that it
anticipates a 10 month duration for facility decommissioning, as well as six months for pre- and
post- decommissioning planning. The applicant further proposes that for estimating purposes,
the project management tasks could necessitate up to two full time employees (FTE) for the 16
month decommissioning period, at $200,000 per FTE. The total applicant estimated cost for
project management and administration, based on these numbers, is $533,000.

The Department has considered the applicant’s proposal, but recommends that Council
continue to apply a 10 percent project management and administration mark-up for the
following reasons. The applicant’s basis for the 10 month assumed duration and two FTE’s is not
supported by sufficient information or evidence. The Department questions the sufficiency of
the assumed duration and FTE requirement to cover all of the necessary process and
contracting requirements, including legal and consultation requirements under the applicant’s
lease agreements, in addition to the actual time necessary to decommission and restore (where
restoration could take several years) the impacts of a 303 MW solar facility and related or
supporting facilities, including an 11-mile 230 kV transmission line. The Council has imposed the
10 percent project management and administration mark-up to retirement bond cost estimates
for all EFSC facilities, and while the Department does not support utilization of the 2005 Facility
Retirement Cost Estimating Guide for cost-estimating purposes, that guide does include the
recommendation of utilizing a 10 percent mark-up for administration and project management.

Because the applicant’s Department project management contingency is based upon an
assumed decommissioning duration that is not supported by evidence, the Department
recommends Council apply a 10 percent project management contingency to the total
decommissioning estimate, consistent with historic contingencies applied by Council for other
EFSC facilities.

Future Development Contingency

The Council has historically applied a future development contingency of 10 to 20 percent to an
applicant’s decommissioning cost estimate based on uncertainty in the decommissioning
estimate. If site restoration becomes necessary, it might be many years in the future where
there is uncertainty of continued adequacy of the retirement cost estimate. Uncertainty factors
include different environmental standards or other legal requirements; and, changes in cost of


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的能力，如果申请人未能履行其义务以恢复现场，申请人应向州提交保函或信用证，佣金的金额应经州理事会批准。保函或信用证应由州批准的发行机构提供，作为受益人或支付人。申请人应描述保函或信用证在理事会授权前的状态，并提供有关文件。保函或信用证的金额应调整为州能源部在其2023年年度报告中批准的金额。申请人应就其在计算过程中的财务保证义务和确保债券或信用证的充分性。”

### Table 5: Department Adjusted Decommissioning Cost Estimate

<table>
<thead>
<tr>
<th>Task</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>$23,036,000</td>
</tr>
<tr>
<td>Performance and Payment Bond (1%)</td>
<td>$100,000</td>
</tr>
<tr>
<td>Future Development (20% of total)</td>
<td>$4,200,000</td>
</tr>
<tr>
<td>Proposed Facility Decommissioning Cost ($1,000)</td>
<td>$23,036,000</td>
</tr>
</tbody>
</table>

### Notes:

- A 10% future development contingency is applied to all tasks, with the exception of the proposed battery storage system (1,8m). A 20% future development contingency is applied to the proposed battery storage system ($82,796).

### Recommended Retirement and Financial Assurance Condition 4:

- Before beginning construction of the facility, the certificate holder may submit to the state of Oregon, through the Council, a bond or letter of credit naming the state of Oregon, acting by and through the Council, as beneficiary or payee. The total bond or letter of credit amount for the facility is $23,036,000 dollars (Q1 2019 dollars), to be adjusted to the date of issuance, and adjusted on an annual basis thereafter, as described in sub-paragraph (b) of this condition.

### Recommended Retirement and Financial Assurance Condition 5:

- Before beginning construction of the facility, or any phase of the facility, the certificate holder may submit to the state of Oregon, through the Council, a bond or letter of credit naming the state of Oregon, acting by and through the Council, as beneficiary or payee. The total bond or letter of credit amount for the facility is $23,036,000 dollars (Q1 2019 dollars), to be adjusted to the date of issuance, and adjusted on an annual basis thereafter, as described in sub-paragraph (b) of this condition.

- The certificate holder may adjust the amount of the bond or letter of credit based on the design configuration of the facility, or any phase of the facility, by applying the unit costs and general costs illustrated in Table 3 of the Final Order on the ASC, and the contingencies illustrated in Table 4 of the Final Order on the ASC. Any revision to the restoration costs should be adjusted to the date of issuance as described in (b). The Council authorizes the Department to agree to these adjustments in accordance with this condition and subject to review and approval by the Council.

- The certificate holder shall adjust the amount of the bond or letter of credit using the following calculation:

  1. Adjust the amount of the bond or letter of credit (expressed in Q1 2019 dollars) to present value, using the U.S. Gross Domestic Product Implicit Price Deflator, Chain-Weight, as published in the Oregon Department of Administrative Services’ “Oregon Economic and Revenue Forecast” or by any successor agency and using the first quarter 2019 index value and the quarterly index value for the date of issuance of the new bond or letter of credit. If at any time the index is no longer published, the Council shall select a comparable calculation to adjust first quarter 2019 dollars to present value.
  2. Round the result total to the nearest $1,000 to determine the financial assurance amount.
  3. The certificate holder shall use an issuer of the bond or letter of credit approved by the Council, based on the Council’s pre-approved financial institution list.
  4. The certificate holder shall use a form of bond or letter of credit approved by the Council. The certificate holder shall describe the status of the bond or letter of credit in the annual report submitted to the Council under OAR 345-026-0080. The bond or letter

### Notes:

- A 10% future development contingency is applied to all tasks, with the exception of the proposed battery storage system (1,8m). A 20% future development contingency is applied to the proposed battery storage system ($82,796).
of credit shall not be subject to revocation or reduction before retirement of the facility
site.

[PRE-RE-02]

Recommended Retirement and Financial Assurance Condition 5b: Consistent with
Mandatory Condition OAR 345-025-0006B1, no later than the date the facility is placed
in service (In-Service Date), the certificate holder shall submit to the State of Oregon,
through the Council, a bond or letter of credit naming the State of Oregon, acting by
and through the Council, as beneficiary or payee. The certificate holder shall maintain a
bond or letter of credit as follows:

a. From the In-Service Date until In-Service Year 20, the amount of bond or letter of
credit shall be $1.00

b. On Year 20, or the termination of the facility PPA, whichever is earlier, the certificate
holder shall begin maintaining a bond or letter of credit in an amount equal to 100
percent of the decommissioning costs less the scrap value credit for the facility.

c. The estimated total decommissioning cost for the facility is $23,016,000 (Q1 2019
dollars), to be adjusted to the date of issuance of the bond or letter of credit in In-
Service Year 20, and on an annual basis thereafter, subject to Department approval, the
certificate holder may request an adjustment of the bond or letter of credit amount
based on final design configuration of the facility by applying the unit costs and general
costs illustrated in Table 3 of the Final Order on the ASC, and the contingencies
illustrated in Table 4 of the Final Order on the ASC. The Council authorizes the
Department to agree to these adjustments in accordance with this condition. The
certificate holder shall adjust the decommissioning cost for inflation using the following
calculation:

i. Adjust the amount of the bond or letter of credit (expressed in Q1 2019 dollars) to
present value, using the U.S. Gross Domestic Product Implicit Price Deflator, Chain
Weight, as published in the Oregon Department of Administrative Services’ “Oregon
Economic and Revenue Forecasts” or by any successor agency and using the first
quarter 2019 index value and the quarterly index value for the date of issuance of
the new bond or letter of credit. If at any time the index is no longer published, the
Council shall select a comparable calculation to adjust first quarter 2019 dollars to
present value.

ii. Round the result total to the nearest $1,000 to determine the financial assurance
amount.

iii. The certificate holder shall use an issuer of the bond or letter of credit approved by
the Council, based on the Council’s pre-approved financial institution list.

iv. This certificate holder shall use a form of bond or letter of credit approved by the
Council. The certificate holder shall describe the status of the bond or letter of credit in
the annual report submitted to the Council under OAR 345-026-0080(1)b. The
certificate holder shall maintain a bond or letter of credit in effect at all times as

In ASC Exhibit W, the applicant requests Council consideration of an alternative phased
approach to decommissioning surety and accounting for the value of scrap metal. The phased
approach would provide for the Department a bond or letter of credit in the full
amount necessary for facility decommissioning, not including scrap value prior to construction,
which would remain in place through construction until the facility was placed into service (In
Service Date). In addition, prior to construction, the applicant would enter into a security
agreement with the State of Oregon through the Council and the Department (collectively, the
State) granting the State a security interest in and priority in the facility scrap value. The
applicant would file a UCC financing statement with the State of Oregon and provide evidence
of the filing to the Department prior to construction. At the In Service Date, the bond or
letter of credit would be reduced to $1 once the facility was in commercial operation. In In
Service Year 20, the applicant would file a phased decommissioning plan, or the last year of the applicant’s Power Purchase Agreement
(PPA), whichever is later, the bond or letter of credit would be based on the full facility
decommissioning amount, not including scrap metal, for the remainder of the facility’s
operational life. If Council were to consider applying the value of scrap metal as a discount to
the decommissioning estimate, the applicant proposes to evaluate changes in scrap metal and
submit annual updates to the Department to verify adequacy of the existing bond or letter of
credit, in addition to proposing to enter into an agreement with the Department to grant the
Department a security interest in facility equipment salvage.

In ASC Exhibit W, the applicant requests Council consideration of an alternative phased
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the decommissioning estimate, the applicant proposes to evaluate changes in scrap metal and
submit annual updates to the Department to verify adequacy of the existing bond or letter of
credit, in addition to proposing to enter into an agreement with the Department to grant the
Department a security interest in facility equipment salvage.

The applicant asserts that a phased approach to the decommissioning bond considers the real-
world economics of utility scale energy projects, as the level of investment in an energy project
of this type are typically on the order of $100 million or more. The applicant describes that this
level of investment is usually made in partnership with one or more equity investors in the
facility. Equity investors in energy projects hire independent evaluators to perform due
diligence on projects prior to investing. Industry independent evaluators typically state the used
and useful life of energy projects, such as the facility, would have a used and useful life of 35
years or more.

Assuming projects have a 35-year useful life, the applicant asserts that if a project owner were
to become insolvent during the lifetime of the facility, the facility’s equity investors would step
in to be sure that the facility would remain operational. The applicant describes that the
industry’s financial and real estate agreements are set up so that equity investors in a facility
can take over the facility should the certificate holder go into default. If a certificate holder goes
into default, the facility’s banks and investors would then file for bankruptcy protection and
find a new buyer to own and operate the project.
The Department has evaluated the applicant's proposal and recommends that the Council find that the applicant may elect to use the alternate decommissioning above and presented in Recommended Retirement and Financial Assurance Condition 4a and b and Condition 5a and b.

Council Appointed Consultant Review of Applicant’s Proposal

In accordance with ORS 469.470(6), at the September 26-27, 2019 meeting, Council appointed Golder Associates, Inc. (Golder) based on their experience and qualifications related to the Council’s Retirement and Financial Assurance standard, as a qualified consultant to provide technical expertise in review of the above-requested approach (i.e. discounted decommissioning amount based on scrap metal value, and a phased decommissioning surety approach). Golder’s scope of work included: review case history and context supporting ODOE’s policy of not allowing scrap value to be applied to decommissioning bond amounts; and evaluate the financial risk of the phased decommissioning surety approach. While Golden raised questions concerning the fluctuating market value of scrap or salvage materials, the Department maintains that the questions concerning risk and market fluctuation have been adequately addressed by the applicant’s February 23, 2020 submittal including a technical memorandum from applicant’s contractor, Tetra Tech, rebutting the findings in the Golden memo and providing further evidence to support a finding that reliance on the established scrap metal market is within reasonable risk levels, particularly with annual reporting and adjustments. In addition, Wasco County specifically provides for the use of scrap value in decommissioning bond estimates (WCLUDO 19.030(C)(19)) and recently approved two solar projects that accounted for scrap value in their respective decommissioning security calculations.

Summary of Review of Applicant’s Request for Use of Scrap Metal Value

Council has historically reviewed requests for consideration of scrap metal value. In the early 2000s, Council allowed retirement bonds to be reduced to account for the value of salvage or scrap metal. In 2006 and 2007, the Department recommended and Council agreed to implement a policy limiting use of scrap value in decommissioning estimates and bond amounts based on concerns of risk related to fluctuating market value, and perhaps more importantly, that third party creditors or other parties could assert a claim against the scrap or salvage value that might result in that value being unavailable to the State to offset site restoration costs. Council requires a potentially costly and lengthy legal challenge by the State in a bankruptcy court to access the value of the salvaged materials. Council has not authorized use of the value of scrap metal to lower a decommissioning estimate since that time.

In addition to reviewing historic Council decisions and policy on use of scrap metal in decommissioning estimates and bond amounts, the Department’s technical expert, Golder reviewed regulatory requirements applicable to industrial facility decommissioning in California, Washington, Alaska, British Columbia and Canada, to determine whether scrap metal value is considered under similar regulatory requirements. Based on this review, Golder found that no state or provincial level programs support use of the value of scrap metal to reduce a decommissioning bond requirement for the state or provincial level permitting programs for these facilities.

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Based on the findings presented here, the Department recommends the Council find that the proposed facility can be restored adequately to a useful, non-hazardous condition following permanent cessation of construction or operation of the proposed facility. Subject to compliance with Retirement and Financial Assurance Conditions 4 and 5, the Department recommends that the Council find that the applicant has a reasonable likelihood of obtaining a bond or letter of credit in a form and amount satisfactory to the Council to restore the site to a useful, non-hazardous condition.

Conclusions of Law

Based on the foregoing recommended findings of fact, and subject to compliance with the recommended conditions, the Department recommends that the Council find that the proposed facility would comply with the Council’s Retirement and Financial Assurance standard.

Subject to compliance with Retirement and Financial Assurance Conditions 1, 2 and 3, the Department recommends the Council find that the proposed facility can be restored adequately to a useful, non-hazardous condition following permanent cessation of construction or operation of the proposed facility. Subject to compliance with Retirement and Financial Assurance Conditions 4 and 5, the Department recommends that the Council find that the applicant has a reasonable likelihood of obtaining a bond or letter of credit in a form and amount satisfactory to the Council to restore the site to a useful, non-hazardous condition.

Conclusions of Law

Based on the foregoing recommended findings of fact, and subject to compliance with the recommended conditions, the Department recommends that the Council find that the proposed facility would comply with the Council’s Retirement and Financial Assurance standard.

Based on the findings presented here, the Department recommends the Council find that the proposed facility can be restored adequately to a useful, non-hazardous condition following permanent cessation of construction or operation of the proposed facility. Subject to compliance with Retirement and Financial Assurance Conditions 4 and 5, the Department recommends that the Council find that the applicant has a reasonable likelihood of obtaining a bond or letter of credit in a form and amount satisfactory to the Council to restore the site to a useful, non-hazardous condition.

Conclusions of Law

Based on the foregoing recommended findings of fact, and subject to compliance with the recommended conditions, the Department recommends that the Council find that the proposed facility would comply with the Council’s Retirement and Financial Assurance standard.
To issue a site certificate, the Council must find that the design, construction and operation of the facility, taking into account mitigation, are consistent with:

(1) The general fish and wildlife habitat mitigation goals and standards of OAR 635-415-0025.

This rule creates requirements to mitigate impacts to fish and wildlife habitat, based on the quantity and quality of the habitat as well as the nature, extent, and duration of the potential impacts to the habitat. The rule also establishes a habitat classification system based on value the habitat would provide to a species or group of species. There are six habitat categories:

- Category 1 being the most valuable and Category 6 the least valuable.

The analysis area for potential impacts to fish and wildlife habitat, as defined in the project order, is the area within and extending ½ mile from the site boundary. To inform the evaluation of impacts under the Council’s Fish and Wildlife Standard, the applicant completed wetland delineation, surveys, special status plant surveys, botanical surveys, and habitat mapping, as further described below.

Methodology

To inform ASC Exhibit P, the applicant consulted with ODFW and conducted multiple site visits with ODFW regional biologist, Jeremy Thompson. Based on ODFW consultation, multiple recommendations were provided related to minimizing potential impacts to mule deer, mule deer winter range, ground nesting birds and raptor nests, all of which were incorporated as mitigation by the applicant, and recommended by the Department for Council’s inclusion as site certificate conditions.

To identify potential habitat category and types within the analysis area, the applicant’s consultant TetraTech conducted both field and desktop surveys. The applicant’s literature review included Oregon Biodiversity Information Center (ORBIC) (2016, 2018), ODFW’s 2016 Sensitive Species List and 2017 Threatened, endangered and candidate fish and wildlife species list; the 2016 Oregon Conservation Strategy; and United States Fish and Wildlife Service’s 2018 Information for Planning and Consultation, and online critical habitat map for threatened and endangered species. The applicant also reviewed survey information for its adjacent local jurisdictional facility - Imperial Wind, aerial photographs, National Wetlands Inventory data, the National Hydrography Dataset, and big game winter range spatial data to inform habitat characteristics within the analysis area.
1. Potential Impacts to Fish and Wildlife Habitat

2. Construction and operation of the proposed facility would result in temporary, temporal and permanent habitat impacts to Category 2 habitat. Impacts to Category 6 habitat do not require compensatory mitigation under the Council’s Fish and Wildlife Habitat standard. Temporary habitat impacts are those that would last for less than the operational lifetime of the proposed facility and would result during construction and installation of proposed facility components. The duration of temporary impacts to habitat is variable, based on vegetation type and extent. Temporary habitat impacts to require a longer restoration timeframe (+five years) are considered temporal impacts and typically require additional mitigation beyond revegetation to account for the loss of habitat function and values from the time of impact to the time when the restored habitat provides a pre-impact level of habitat function.

3. Permanent impacts are defined as impacts that would exist for the operational life of the proposed facility and would result from placement of permanent facility structures.

4. As presented in Table 6: Summary of Habitat Categories within Micrositing Corridor and Estimated Permanent and Temporary Habitat Impacts from Proposed Facility, the proposed facility would temporarily disturb approximately 157 acres of Category 2 habitat (ranging in quality from Category 3, 4 and 5), resulting in temporary and temporal habitat impacts. The proposed facility would permanently disturb approximately 2,473 acres of Category 2 habitat (ranging in quality from Category 3, 4 and 5).

### Table 6: Summary of Habitat Categories within Micrositing Corridor and Estimated Permanent and Temporary Habitat Impacts from Proposed Facility

<table>
<thead>
<tr>
<th>Habitat Category and Type</th>
<th>Micrositing Corridor</th>
<th>Perm.</th>
<th>Temp.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Category 2:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wetlands – Emergent Wetlands</td>
<td>5.7</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Wetlands – Shrub-scrub Wetlands</td>
<td>0.1</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Riparian Forest and Natural Shrubland Complexes – Eastside Riparian</td>
<td>19.0</td>
<td>0.6</td>
<td>1.3</td>
</tr>
<tr>
<td>Upland Grassland, Shrub-Steppe and Shrubland</td>
<td>2,087.6</td>
<td>1,674.6</td>
<td>48.8</td>
</tr>
<tr>
<td>Upland Grassland, Shrub-Steppe and Shrubland - Shrub-Steppe</td>
<td>670.2</td>
<td>166.3</td>
<td>80.2</td>
</tr>
<tr>
<td>Agriculture, Pasture, Mixed Environments – Planting Grassland</td>
<td>948.4</td>
<td>600.6</td>
<td>24.2</td>
</tr>
<tr>
<td>Cliffs, Caves, and Talus</td>
<td>3.0</td>
<td>0.0</td>
<td>0.4</td>
</tr>
<tr>
<td>Open Water - Lakes Rivers Streams – Seasonal Pond</td>
<td>2.7</td>
<td>0.7</td>
<td>0.1</td>
</tr>
<tr>
<td>Open Water - Lakes Rivers Streams – Intermittent or Ephemeral Stream</td>
<td>0.8</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Upland Forests and Woodlands – Juniper Woodland</td>
<td>25.9</td>
<td>0.0</td>
<td>2.6</td>
</tr>
<tr>
<td>Category 6:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Agriculture, Pasture, Mixed Environments – Orchards, Vineyards, Wheat Croppers and Other Row Crops</td>
<td>323.7</td>
<td>240.4</td>
<td>4.3</td>
</tr>
</tbody>
</table>

Notes:
1. Proposed Habitat Mitigation
2. The mitigation goal for Category 2 habitat is no net loss of either habitat quantity or quality and provision of a net benefit of habitat quantity or quality. To achieve this goal, impacts must be avoided or unavoidable impacts must be mitigated through "reliable in-kind, in-proximity" habitat mitigation to achieve no net loss; and a net benefit of habitat quantity or quality must be provided.11
3. As presented in the draft Revegetation Plan, provided as Attachment K of this order, the applicant proposes to mitigate temporary, non-temporal habitat impacts through revegetation and noxious weed control. As presented in the draft Revegetation Plan prior to construction, the applicant proposes to:

proposes to identify monitoring sites, including both a reference and monitoring site, for each
habitat subtype to be impacted by the proposed facility. The final number of monitoring sites
per habitat would be based on the extent and diversity of vegetation within each habitat type, with
an anticipated average of two to five paired monitoring sites per habitat type, to be
reviewed and approved by the Department in consultation with ODFW. The applicant would
then be obligated to monitor and report on the success of revegetation at the identified
monitoring sites; success would be measured, as specified in Section 7.3 of the draft plan,
based on percentage of desirable vegetation cover, vegetation density and weed cover. The
applicant proposes to conduct annual monitoring of monitoring sites for the first 5 years post-
construction, and would ultimately be based on the impacted habitat recovery period.
As represented in the draft Plan, if after 5 years, additional remedial actions are determined
necessary by either the applicant, the Department or ODFW, annual reporting would continue
until reclamation actions have satisfied all success criteria. If, after 5 years of annual
monitoring, some sites have not attained the success criteria or if at any point during the
annual monitoring it is clear that revegetation cannot be successful, the applicant commits to
coordinating with the Department and ODFW on reseeding, weed control or other remedial
measures determined appropriate. Based on compliance with the draft Revegetation and Weed
Control Plans provided as Attachment I and K of this order, the Department recommends the
Council find that the applicant would meet the habitat mitigation goals for temporary habitat
impacts. Based on the applicant’s draft plans, and in order to provide the Department, ODFW
and Wasco County Planning/Weed Department the opportunity to review final plans, the
Department recommends Council impose the following conditions:

Recommended Fish and Wildlife Habitat Condition 1: The certificate holder shall:
1. Finalize and submit a Revegetation Plan, based upon the draft plan provided in
Attachment I of the Final Order on the ASC, for review and approval by the Department,
in consultation with ODFW and Wasco County Planning Department. The scope of
finalizing the plan shall, at a minimum, include the following:
(a) Final assessment of temporary habitat impacts (in acres), based on habitat
quality of habitat subtype, and final facility design, presented in tabular format.
(b) Survey and sampling protocol for evaluating the success criteria against paired
monitoring and reference sites determined to represent a statistically significant
number of sites based on pre-disturbance habitat quality and diversity of habitat
temporarily impacted.
(c) Description of deep soil decompaction measures to be implemented.
2. During construction and operation of the facility or any phase of the facility, the
certificate holder shall implement the requirements of the plan; monitor and report
results of revegetation activities to the Department, as required by the plan.

[ODFW-DP-01]

Recommended Fish and Wildlife Habitat Condition 2: The certificate holder shall:

a. Prior to construction of the facility or any phase of the facility, the certificate holder
shall finalize and submit a Noxious Weed Control Plan, based upon the draft plan
provided in Attachment K of the Final Order on the ASC, for review and approval by the
Department, in consultation with ODFW and Wasco County Planning Department.
Components of the plan to be finalized shall include, at a minimum:
1. Pre-disturbance survey or assessment of noxious weed species within areas to be
impacted.
2. Reporting format including report content and supporting materials to be
included to demonstrate completion of noxious weed control activities.
b. During construction and operation of the facility or any phase of the facility, the
certificate holder shall implement the requirements of the plan.

[ODFW-DP-02]
every 1 acre of Category 2 with Category 3, 4 and 5 quality, respectively, for habitat permanently impacted (a ratio ranging from 1:3 to 1:1 to provide no net loss and a net benefit of habitat quality). Based on this proposed methodology, the HMA for the proposed facility would include approximately 3,039 acres as mitigation for permanent and temporal habitat loss. Based on the Department’s review of the applicant draft HMP, in coordination with ODFW, the Department recommends Council find that the proposed mitigation would satisfy the Council’s Fish and Wildlife Habitat standard, and recommends Council impose the following condition:

**Recommended Fish and Wildlife Habitat Condition 3:** The certificate holder shall:

a. Prior to construction of the facility or any phase of the facility, the certificate holder shall finalize and submit a Habitat Mitigation Plan, based upon the draft plan provided in Attachment H of the Final Order on the ASC, for review and approval by the Department, in consultation with ODFW. In the finalization of the plan, the Department may request specific reporting requirements including specific information, frequency and format. Components of the plan to be finalized shall include, at a minimum, a final assessment of permanent habitat impacts (in acres) based on habitat quality of habitat subtype, and final facility design, presented in tabular format.

b. If Option 2 is selected, the certificate holder shall:

i. Provide a copy of the executed Memorandum of Understanding with the land management entity demonstrating local acquisition of lands to satisfy ODFW’s Category 3 habitat mitigation goal (net benefit; no net loss; quantity, quality and location), confirms applicability of mitigation equation as presented in the plan, and includes a copy of the management plan with enhancement actions, as extant in the plan, for which the third party land management entity agrees to adhere.

ii. Provide a parent company guarantee, or equivalent financial security agreement, to the Department including terms and conditions which would result in new compensatory mitigation in the event reports from the third-party land management entity demonstrate long-term failure (i.e. documented trends not achieving success with plan’s success criteria) of the mitigation area, or other mitigation actions such as different enhancement actions at the mitigation area.

c. If Option 3 is selected, the certificate holder shall:

i. Acquire the legal right to create, enhance, maintain, and protect a habitat mitigation area, as long as the site certificate is in effect by means of an outright purchase, conservation easement or similar conveyance, and shall provide a copy of the documentation to the Department. Within the habitat mitigation area, the certificate holder shall improve the habitat quality as described in the Final Habitat Mitigation Plans for each phase of the facility.

ii. Provide a habitat assessment of the habitat mitigation area, based on a protocol approved by the Department in consultation with ODFW, which includes methodology, habitat map, and available acres by habitat category and subtype in tabular format.

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As presented in ASC Exhibit P, the following sensitive species were identified within the proposed facility construction and operation due to the introduction of noxious weeds and other non-native invasive species, potential nesting and breeding disturbance, electrocution, powerline collision, structure collision, vehicular collision, disturbance related to artificial lighting, entrapment within open vertical pipes, disturbance to wintering big game, and entrapment within fenced area.

- Bald eagle (BGEPA). Bald eagles were not observed within the analysis area during 2018 special status species surveys but were recorded as transients during nearby surveys performed by Avangrid Renewables. No bald eagle nests are located within 10 miles of the proposed micrositing corridor (WEST 2018). Bald eagles are observed during all months of the year in Wasco County (Sullivan et al. 2009). The Deschutes River provides bald eagle habitat, and a winter roost comprised of several individuals has been documented near where Buckhollow Creek empties into the Deschutes River (NWC 2011). Bald eagles primarily hunt in or near aquatic habitats, but opportunistically forage on carrion, particularly in winter (Buettner 2000). Powerline collision and electrocution are the primary potential, adverse impacts to bald eagles, mainly during migration and winter.¹²

- Brewer’s sparrow (state sensitive). Brewer’s sparrows were not observed during 2018 surveys at the facility. This species uses shrublands, generally with a canopy height of more than 5 feet. Brewer’s sparrows are most closely associated with big sagebrush (Artemesia tridentata). Potential adverse impacts to this species due to the construction and operation of the proposed facility are habitat loss and potential nesting disturbance in areas where limited stands of larger shrubs may be located. Additionally, collision with infrastructure during nocturnal migration may be an adverse impact to this species.

- Burrowing owl (state sensitive-critical). This species breeds in burrows excavated by other animals in open areas with a high proportion of bare ground (OCS 2016). A family group of two adults and three young was observed during 2018 surveys in the proposed micrositing corridor, at a site consisting of two burrows (Figure P-5). Potential adverse impacts to this species during construction are nesting and foraging habitat loss (burrows and grassland, respectively), and vehicle collision.

¹² Bald and golden eagles are not listed by ODFW as a state-sensitive species, and the applicant must comply with the Bald and Golden Eagle Protection Act independent of the OFSC site certificate process.
• Common night hawk (state sensitive). Common night hawk was not observed in the analysis area during 2018 surveys but has been recorded during nearby surveys performed by Avangrid Renewables (Attachment P-1). A long-distance migrant, this species is only present in Oregon during its breeding season, arriving in mid- to late May (Brigham et al. 2011). Common night hawks are rarely observed in Wasco County after August (Sullivan et al. 2009). Surveys were conducted during this species’ breeding period in Oregon; however, common night hawks are most active at dusk and dawn. Construction and operation of the proposed facility could pose a risk to these birds, which nest on a variety of substrates in open areas including bare ground, gravel, and thiolos. Males also tend to roost on gravel roads, and therefore may roost in temporary impact areas in use during construction such as staging areas. During construction and operation, nesting disturbance and collision with vehicles may adversely impact this species.

• Ferruginous hawk (state sensitive-critical). This species occurs in open, grassy areas and shrub-steppe with scattered shrubs or trees for perching and nesting. They can nest in juniper or cottonwood trees near small streams, on rocky sites with an expansive view, on rimrock, or on undisturbed ground (OCS 2016). Nesting opportunities for this species are limited within the proposed micrositing corridor, but the available habitat is appropriate for hunting during the breeding season and during migration. Surveys at the Facility occurred during the breeding period, when this species was most likely to be observed. This species was not detected during 2018 surveys within the proposed micrositing corridor, but has been recorded during nearby surveys performed by Avangrid Renewables (Attachment P-1). In addition to potential electrocution and powerline collision, impacts to this species include habitat loss and potential nesting disturbance if ferruginous hawks build new nests adjacent to, but outside the proposed micrositing corridor.

• Golden eagle (BGEPA). Golden eagles are known to nest on rocky cliffs along the Deschutes and John Day rivers, outside the analysis area (ORBIC 2018). Avangrid Renewables (NWC 2011; WEST 2018) and the Oregon Eagle Foundation (Isaacs 2018) have observed eagles nesting along Buck Hollow and the lower portions of the Bakeoven Creek drainage. Potential powerline collision and electrocution are more likely potential impacts to golden eagles than habitat disturbance due to the construction and operation of the Facility. GOLDEN EAGLE

• Grasshopper sparrow (state sensitive). Grasshopper sparrows were not recorded during 2018 surveys at the Facility, but were recorded during surveys at the adjacent Imperial Wind Project (Attachment P-1). This species uses dry grasslands with low shrub cover for breeding (OCS 2018). In Oregon, this species breeds primarily in native bunchgrass. Its breeding period generally begins in May (Vickery 1996). This species may be attracted to artificial lights during migration; therefore, collision is an additional potential, adverse impact to this species during construction and operation of the proposed facility.

11 Bald and golden eagles are not listed by ODFW as a state-sensitive species, and the applicant must comply with the Bald and Golden Eagle Protection Act independent of the EFSC site certificate process.

• Lewis’ woodpecker (sensitive-critical). Habitat disturbance due to the 2018 Biocar fire has increased the potential for this species to occur within the analysis area. This cavity nesting species may find increased nesting opportunities in snags in the riparian canyons adjacent to the proposed micrositing corridor (Vierling et al. 2013). This species has limited potential to occur at the proposed facility as a vagrant during migration. Construction of the proposed facility would not result in a loss of habitat for this species. A diurnal migrant, this species will be not adversely impacted by artificial lighting.

• Loggerhead shrike (state sensitive). This species uses patches of tall brush or trees in open habitats for nesting and roosting, and forages in open areas with grasses and bare ground (Coil et al. 2001; OCS 2016). This species was not observed during 2018 surveys but is known to occur nearby (Attachment P-1). The primary potential adverse effects to loggerhead shrike are habitat loss and nesting disturbance.

• Long-billed curlew (state sensitive-critical). This grassland-associated species prefers shorter grass, and can occur in dryland wheat (Dugger and Dugger 2002; OCS 2016). Long-billed curlews were not observed during 2018 surveys, but have been observed nearby (Attachment P-1). Potential adverse impacts due to proposed facility operation are limited to the migration window for this species during the spring and early summer, and consist only of potential collision with vehicles intermittently operating on site.

• Sagebrush sparrow (state sensitive-critical). This often difficult-to-detect species is found in shrub-steppe habitat with high shrub cover, and is closely associated with big sagebrush communities (Martin and Carlson 1998; OCS 2016). This species was not observed during 2018 surveys, but it occurs in Wasco County (ORBIC 2016). Potential adverse effects to sagebrush sparrows are habitat loss, nesting disturbance, and possibly lighting-related disturbance during migration, though its migratory behavior is poorly described.

• Swainson’s hawk (state sensitive). Swainson’s hawks are open-country specialists that hunt and forage in grassland, shrub-steppe, and agricultural areas, and often focus on row crop agriculture. Nests are frequently in lone trees or isolated shrubs in open country. In the non-breeding season, particularly during fall migration in North America, they are often observed hunting in groups behind agricultural equipment, opportunistically preying on rodents and insects (Bechard et al. 2010). This species was observed twice in the proposed micrositing corridor during 2018 surveys (Figure P-5). Nearby surveys performed by the applicant in 2018 identified three nests near Route 97, approximately 6 miles south of the analysis area (Attachment P-1). Construction will result in permanent and temporary impacts to habitat appropriate for hunting during breeding and migration. Nesting disturbance could also occur if Swainson’s hawks build new nests adjacent to the proposed micrositing corridor.
• Northern sagebrush lizard (state sensitive). This species occurs in shrub-steppe and
juniper woodland habitat with sandy soils and sparse vegetation in the grass/forb layer
(OCE 2016). Northern sagebrush lizards were not observed during 2018 surveys, but have
been recorded during nearby surveys. Potential adverse impacts to this species include loss
of habitat and disturbance during construction if individuals are present.
• California Mountain Kingsnake (state sensitive). This species occurs in oak and pine
woodlands, which are limited within the analysis area and in the proposed microsite
corridor (Table P-3; OCE 2016). No records of California mountain kingsnake were
identified by an ORBIC query by the Applicant (ORBIC 2018); however, this species occurs
within Wasco County and is sensitive in the Columbia Plateau ecoregion (ORBIC 2016;
ODFW 2016). Potential adverse impacts to this species include loss of habitat and
disturbance during construction if individuals are present.
• Based upon potential impacts of the proposed facility to the above-described sensitive species
(both federal and state), including introduction of noxious weeds and other non-native invasive
species, potential nesting and breeding disturbance, electrocution, powerline collision,
structure collision, vehicular collision, disturbance related to artificial lighting, entrapment
within open vertical pipes, disturbance to wintering big game, and entrapment within fenced
area, the applicant proposed a suite of mitigation measures which are represented as
recommended conditions below:

Recommended Fish and Wildlife Habitat Condition 4: During design of the facility or any
phase of the facility, the certificate holder shall ensure that:

a. Aboveground transmission lines, including the 230 kV transmission line and
aboveground segments of 54.5 kV collector line, adhere to current APLIC guidelines for
minimizing avian electrocution risk associated.

b. Spiral markers are installed on the 230 kV transmission line ground wire, in locations
where the line crosses over canyons or would be located within 2 miles of a known
eagle nest.

c. Vertical pipe and piles are capped or otherwise modified to prevent entrance or use by
cavity dwelling and nesting birds.

d. Extra gates are installed within the perimeter fenceline to allow big game to escape if
trapped.

[GEN-FW-04]

Recommended Fish and Wildlife Habitat Condition 5: Prior to construction of the facility or
any phase of the facility, the certificate holder shall conduct a raptor nest survey within 0.5
mile of the defined work area to identify the location of raptor nests that could be affected
by construction. The certificate holder shall submit to the Department, for review and
concurrency, a survey protocol that identifies the survey area and methods to be used to
identify raptor nests.

[PRE-FW-01]

Recommended Fish and Wildlife Habitat Condition 6: If active raptor nests are identified
during the pre-construction surveys completed in accordance with Fish and Wildlife Habitat
Condition 6, the certificate holder shall adhere to the spatial buffer and seasonal
restrictions, for state-sensitive species, presented in the table below. For non-state sensitive
species, the certificate holder shall adhere to the spatial buffer and seasonal restrictions, to
the extent feasible.

<table>
<thead>
<tr>
<th>Species</th>
<th>Spatial Buffer</th>
<th>Seasonal Restriction</th>
<th>Release Date if Unoccupied</th>
</tr>
</thead>
<tbody>
<tr>
<td>Western Burrowing Owl</td>
<td>0.25 mile</td>
<td>April 1 – August 15</td>
<td>May 31</td>
</tr>
<tr>
<td>Golden eagle</td>
<td>0.5 mile</td>
<td>Feb 1 – Aug 15</td>
<td>May 15</td>
</tr>
<tr>
<td>Red-tailed hawk</td>
<td>100/500 feet</td>
<td>Mar 1 – Aug 15</td>
<td>May 31</td>
</tr>
<tr>
<td>Ferruginous hawk</td>
<td>0.25 mile</td>
<td>Mar 15 – Aug 15</td>
<td>May 31</td>
</tr>
<tr>
<td>Swainson’s hawk</td>
<td>0.25 mile</td>
<td>Apr 1 – Aug 15</td>
<td>May 31</td>
</tr>
<tr>
<td>Prairie falcon</td>
<td>0.25 mile</td>
<td>Mar 15 – Jul 1</td>
<td>May 15</td>
</tr>
<tr>
<td>Peregrine falcon</td>
<td>0.25 mile</td>
<td>Jan 1 – Jul 1</td>
<td>May 15</td>
</tr>
<tr>
<td>American kestrel</td>
<td>0.25 mile</td>
<td>Mar 1 – Jul 31</td>
<td>May 15</td>
</tr>
</tbody>
</table>

If a nest becomes active during construction that was not identified as active during the pre-
construction surveys, the certificate holder may request review by the Department, in
consultation with ODFW, of an exception to the spatial buffer and seasonal restrictions.

[CON-FW-01]

Recommended Fish and Wildlife Habitat Condition 7: Prior to and during construction of
the facility or any phase of facility construction, the certificate holder shall:

a. Conduct surveys to identify active burrowing owl burrows, using a qualified
biologist, within suitable habitat within the microsite corridor.

b. If there are any active burrows identified per (a) of this condition, a qualified
biologist shall ensure that these nest locations are covered outside of the breeding
season.

c. To the extent practical, schedule vegetation clearing activities to occur before the
critical period for ground-nesting birds (April 15 – September 1), to avoid
disturbing active nests.

i. Any burrowing owl burrows identified inside the facility perimeter
fenceline will be removed during vegetation clearing.

d. If vegetation clearing activities are necessary between April 15 to September 1, the
certificate holder shall hire a qualified biologist to conduct a clearance survey for nesting
birds prior to vegetation removal. The certificate holder shall ensure that active nest
sites identified during the clearance survey are flagged and marked as sensitive areas on
construction maps.

[PRE-FW-02]

Recommended Fish and Wildlife Habitat Condition 8: Prior to and during construction of
the facility or any phase of facility construction, the certificate holder shall:

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a. Develop constraint maps for construction contractors and facility personnel presenting
the location of streams, wetlands, and other sensitive habitat features (e.g., mature
trees, intact sagebrush) within the microwaving corridor that are not proposed to be
impacted. These maps should also show buffer zones and temporal restrictions of
sensitive resources.

b. Install flagging around all sensitive resources identified under (a) of this condition.

c. Educate construction workers on avoidance of sensitive resources and instruct workers
to avoid and conduct work outside of the sensitive areas.

d. Minimize construction activities outside of the facility perimeter fence line during mule
deer winter range sensitive season (December 1 through April 1).

e. Impose a 20 mile per hour speed limit on all facility access roads (excluding public
roads).

[PRE-FW-03]

Recommended Fish and Wildlife Habitat Condition 9: The certificate holder shall:

a. Prior to construction of the facility or any phase of the facility, the certificate holder
shall finalize and submit a Wildlife Monitoring Plan (WMP), based upon the draft plan
provided in Attachment J of the Final Order on the ASC, for review and approval by the
Department, in consultation with ODFW.

b. During operation of the facility or portions of the facility, the certificate holder
shall implement and comply with the requirements of the WMP, as finalized under (a) of
this condition. [GEN-FW-05]

Conclusions of Law

Based on the foregoing findings of fact and conclusions, and subject to compliance with the
recommended site certificate conditions, the Department recommends the Council find that
the proposed facility would comply with the Council’s Fish and Wildlife Habitat standard.

IV.I. Threatened and Endangered Species: OAR 345-022-0070

To issue a site certificate, the Council, after consultation with appropriate state agencies,
must find that:

(1) For plant species that the Oregon Department of Agriculture has listed as
threatened or endangered under ORS 564.105(2), the design, construction and
operation of the proposed facility, taking into account mitigation, are not likely to
cause a significant reduction in the likelihood of survival or recovery of the species.

(a) The Oregon Department of Agriculture has adopted under ORS 564.105(3); or

(2) For wildlife species that the Oregon Fish and Wildlife Commission has listed as
threatened or endangered under ORS 496.172(2), the design, construction and
operation of the proposed facility, taking into account mitigation, are not likely to
cause a significant reduction in the likelihood of survival or recovery of the species.

Findings of Fact

The Threatened and Endangered Species standard requires the Council to find that the design,
construction, and operation of the proposed facility are not likely to cause a significant
reduction in the likelihood of survival or recovery of a fish, wildlife, or plant species. The
Council must also find that the proposed facility is consistent with an adopted protection and
conservation program from ODA. Threatened and endangered species are those listed under
ORS 564.105(2) for plant species and ORS 496.172(2) for fish and wildlife species. For the
purposes of this standard, threatened and endangered species are those identified as such by
the Oregon Department of Agriculture or the Oregon Fish and Wildlife Commission. 6

The analysis area for threatened or endangered plant and wildlife species, as defined in the
Project Order, is the area within and extending 5 miles from the amended site boundary.

Methodology – Literature Review

In order to identify threatened or endangered species that might occur within the analysis area,
the applicant consulted with the Oregon Department of Fish and Wildlife (ODFW) and
conducted 2018 literature and field surveys. The certificate holder’s 2018 literature review
evaluated the following sources:

- Burke Museum of Natural History and Culture (2018)
- Oregon Department of Fish and Wildlife’s (ODFW) 2016 Oregon Conservation Strategy
- Oregon Department Agriculture’s 2018 Oregon Listed Plants by County
- ODFW’s 2016 Sensitive Species List
- ODFW’s 2017 Threatened, endangered and candidate fish and wildlife species list
- Oregon Biodiversity Information Center 2016 Rare, Threatened and Endangered Species
  of Oregon

6 Although the Council’s standard does not address federally listed threatened or endangered species, certificate
holders must comply with all applicable federal laws, including laws protecting those species, independent of the
site certificate.
Based on the 2018 literature review, two listed threatened or endangered species were identified with the potential for occurrence within 5 miles of the proposed site boundary including one mammal and one plant. These species include Wolverine (Gulo gulo, state listed threatened species, federal proposed threatened) and Tygh Valley milkvetch (Astragalus tyghensis; state listed threatened species; no federal status). It is noted that an additional seven listed or federally listed, proposed, candidate, delisted species and species of concern under the jurisdiction of the Fish and Wildlife Service which may occur in Oregon were not further evaluated as potential species that could be impacted. In addition, the applicant identifies the following four federally listed species (two mammals and two fish species) with potential to occur within the analysis area: Canada lynx (Lynx canadensis; federally threatened, no state status), the gray wolf (Canis lupus; federally endangered, state delisted), steelhead (Opechancus mykiss; Middle Columbia River Evolutionarily Significant Unit/Species Management Unit, summer run; federally threatened, state sensitive-critical), and bull trout (Salvelinus confluentus; Columbia Basin District Population Segment, Deschutes Species Management Unit; federally threatened, no state status in the Columbia Plateau).

Methodology – Field Surveys

The applicant conducted botanical surveys in June/July 2018 using the Intuitive Controlled Methodology. As noted throughout ASC Exhibit Q, in Results of 2018 special status wildlife and botanical surveys resulted in no observations of state listed threatened plant species, Tygh Valley milkvetch, identified through literature review as requiring a pre-construction botanical survey to verify the presence or absence of the state-listed threatened plant species. Tygh Valley milkvetch, identified through literature review as having a potential to occur within the proposed 230 kV transmission line corridor.

Recommended Threatened or Endangered Species Condition 1: Prior to construction or operation of the facility or any phase of the facility, the certificate holder shall:

a. Conduct botanical surveys to confirm the presence or absence of Tygh Valley milkvetch, a state listed threatened plant species, within areas of permanent or temporary disturbance. The certificate holder shall submit a survey protocol to establish the survey area and methods to the Department for review, in consultation with the Oregon Department of Agriculture or third-party consultant, as necessary.

b. If the pre-construction surveys identify Tygh Valley milkvetch, or any other state threatened or endangered plant species, the certificate holder shall complete an impact assessment to determine whether temporary or permanent impacts would significantly reduce the likelihood of survivability or recovery of the impacted species, and shall propose mitigation, as determined appropriate by the Department, in consultation with the Oregon Department of Agriculture or its third-party consultant, as necessary.

Conclusions of Law

Based on the foregoing recommended findings of fact and conclusions, and subject to compliance with the recommended site certificate condition, the Department recommends that the Council find that the proposed facility would comply with the Council’s Threatened and Endangered Species standard.

IV. Scenic Resources: OAR 345-022-0080

(1) Except for facilities described in section (2), to issue a site certificate, the Council must find that the design, construction and operation of the facility, taking into account mitigations, are not likely to result in significant adverse impact to scenic resources and values identified as significant or important in local land use plans, tribal land management plans and federal land management plans for any lands located within the analysis area described in the project order.

* * *

**Note:** The proposed facility is not a special criteria facility under OAR 345-015-0310; therefore OAR 345-022-0080(2) is not applicable.
Findings of Fact

The Scenic Resources standard requires the Council to find that visibility of proposed facility structures, plumes, vegetation loss and landscape alterations would not cause a significant adverse impact to identified scenic resources and values. To be considered under the standard, scenic resources and values must be identified as significant or important in local land use plans, tribal land management plans, and/or federal land management plans.

The analysis area for the Scenic Resources standard is the area within and extending 10 miles from the proposed site boundary, as presented in ASC Exhibit R Figure R-1: Analysis Area for Scenic Resources.

Applicable Land Use and Management Plans

The applicant evaluates multiple land use management plans to determine whether scenic resources were identified as significant or important within the analysis area. As presented in ASC Exhibit R, Table R-1: Inventory of Scenic Resources, reviewed plans include the following:

- Wasco County Comprehensive Plan (WCCP) 1983, as updated through 2010
- Sherman County Comprehensive Land Use Plan 1994, as updated through 2007
- City of Maupin Comprehensive Land Use Plan Update (2005)
- City of Shaniko Comprehensive Land Use Plan (1978)

Based on review of the above-referenced plans, the applicant identifies that the WCCP includes the following important or significant scenic resources within the analysis area:

- Deschutes River: Areas within the river canyon that can be seen from the Deschutes River or lands designated under the State Scenic Rivers Act.
- White River: Lands within the river canyon, or lands within approximately 4 miles of the river.
- Designated Scenic Routes: Specific segments along US 97, US 197, OR 216, OR 218

The Department reviewed the WCCP and consulted with Wasco County Planning Staff (Will Smith, Senior Planner) to confirm that the above-listed scenic resources are identified in the WCCP as significant or important. A summary of each important or significant scenic resource is presented below.

Deschutes River

The Deschutes River is a federally-designated wild and scenic river pursuant to 16 U.S.C. 1271 and is listed in the WCCP as an outstanding scenic and recreation area; therefore, it is identified and evaluated under Council’s standard as an important or significant scenic resource. The approximate distance from the proposed site boundary to the Deschutes River ranges from 2.5 to 5 miles.

White River

The White River is a federal wild and scenic river pursuant to 16 U.S.C. 1271, and is listed in the WCCP as an outstanding scenic and recreation area; therefore, it is identified and evaluated under Council’s standard as an important or significant scenic resource. The proposed site boundary is approximately 3 miles from the White River.

Designated Scenic Routes (US 97 and 197, OR 216 and 218)

- US 97 (Milepost (MP) 30.00 – 48.81, 48.81 – 56.04, 56.72 – 68.66), US 197 (MP 22.42 – 43.83, 47.00 – 50.00), OR 216 (MP 0.00 – 26.17, 6.00 – 8.30), and OR 218 (MP 0.56 – 7.31, 8.3 – 11.00)
- are designated scenic highways in the WCCP, defined as route segments “adjacent to or passing through scenic areas in State of Federal parks, historic sites, or any area of natural beauty that has been designated a scenic area by the Wasco County Scenic Area Board.” Based on the Wasco County Scenic Area Board’s designation of the above-referenced route segments as scenic routes and inclusion in the WCCP as a scenic highway, these highway route segments are identified and evaluated under Council’s standard as significant or important scenic resources.

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16 U.S.C. 1271. The White River is a federal wild and scenic river pursuant to 16 U.S.C. 1271, and is listed in the WCCP as an outstanding scenic and recreation area; therefore, it is identified and evaluated under Council’s standard as an important or significant scenic resource.

39 The Deschutes River is a state-designated scenic waterway pursuant to ORS 390.826; however, ORS 390.825 limits the area included in the scenic waterway to within 0.5 mile of the bank of the river and ORS 390.826(5) excludes the boundaries of the City of Maupin. Therefore, the basis of the impact assessment under the Council’s Scenic Resources standard at the Deschutes River is its consideration as an important or significant scenic resource under the WCCP and 16 U.S.C. 1271, and not as a state scenic waterway.

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OR 390.805 limits the area included in the scenic waterway to within 0.5 mile of the bank of the river and ORS 390.826(5) excludes the boundaries of the City of Maupin. Therefore, the basis of the impact assessment under the Council’s Scenic Resources standard at the Deschutes River is its consideration as an important or significant scenic resource under the WCCP and 16 U.S.C. 1271, and not as a state scenic waterway.
The approximate distance from the proposed site boundary to US 97 is 8 miles, to US 197, 4 to 5 miles to OR 216, and 8 miles to OR 218.

Visual Impacts

Under the Scenic Resources standard, consistent with the information requirement under DAR 345-021-0010(X)(C), potential visual impacts from loss of vegetation, alteration of landscape, facility structures and plumes during proposed facility-related construction and operations are evaluated. The proposed facility would not result in plumes and therefore plume-related visual impacts would not occur. Additionally, the potential for glare from solar panels is sometimes identified as a potential visibility impact, but is addressed through the applicant's proposed design feature to select technology with antireflective coating, as described below in recommended Scenic Resources Condition 1.

Dimensions and footprint of proposed facility structures, including height and area, are considered when evaluating proposed facility visual impacts at important or significant scenic resources within the analysis area; for the proposed facility, the dimensions and footprint of facility components are summarized below:

- 303 MW of solar facility components occupying up to 2,717 acres, with approximately 150,300 posts, with a maximum array tilt height of 12 feet
- 8 foot solar facility perimeter chain-link fencing
- 34.5 kV overhead collector line, extending approximately 4.2 miles, on 60 to 75 foot tall single or double-circuit wood monopole structures;
- Collector substation on 3-acre area, with structure extending 10 feet in height;
- D&M building on 3-acre area, with structure extending 20 feet in height
- Battery storage system (containers) on 8.4 acre area, with containers extending 20 feet in height
- 230 kV transmission line, extending approximately 11 miles, on 80 to 100 foot tall steel or wood H-frame pole structures, or single metal monopole structures;

Visual Impact Assessment Methodology

The applicant’s visual impact assessment methodology includes bare-earth modeling, zone of visual influence (ZVI) analyses. The ZVI analyses were performed using the Spatial Analyst extension of the ESRI ArcGIS software, using a 10 meter digital elevation model to represent the terrain within the analysis area. The ArcGIS software generates lines of sight from the three-dimensional coordinates of the proposed solar facilities (i.e. solar arrays, battery storage system, D&M building, 230 kV transmission line, and overhead 34.5 kV collector line) to points on the terrain surface (factoring a 6-foot offset for viewer height), thereby identifying locations from which the proposed facility components would potentially be visible.\(^{1}\) in ASC Exhibit R, the applicant explains that a bare-earth analysis does not take into account the visibility effects of existing vegetation or buildings, which in practice would block or screen views in some places. In addition, the ZVI model does not account for distance, lighting and atmospheric factors (such as weather) that can diminish visibility under actual field conditions. In other words, the results of the ZVI analysis, which present potential lines of site of proposed facility components, is extremely conservative in identifying potential visibility impacts. The results of the applicant’s ZVI analyses is presented in Figure 6: Viewshed Analyses for Proposed Facility Components below.

\(^{1}\) OAR 0108111-000002: Viewshed Analyses for Proposed Solar Facility Components

The proposed facility would result in temporary and permanent vegetation loss. Temporary vegetation loss would be restored through the applicant’s implementation of a final Revegetation Plan and Noxious Weed Control Plan, to be reviewed and approved by the Department prior to construction, in accordance with recommended Fish and Wildlife Habitat Conditions 1 and 2. Proposed facility operation would result in permanent vegetation loss from the footprint of facility components. In ASC Exhibit R, the applicant represents that the
proposed facility site would be cleared and graded, but that views of the graded area, or
can changes in vegetation, would be obscured by views of proposed facility components. The
3 Deschutes River Canyon is the closest significant or important scenic resource to the proposed
4 site boundary, at over 2 miles. Based on this distance, visibility of temporary and permanent
5 vegetation loss would not be expected. Therefore, the Department recommends Council find
6 that visual impacts from vegetation loss associated with proposed facility construction and
7 operation would not be visible from any important or significant scenic resource and therefore
8 would not result in significant, adverse impacts at important or significant scenic resource
9 within the analysis area.
10
11 Potential Visual Impacts from Facility Structures
12
13 The applicant evaluates potential visibility impacts from proposed facility structures using the
14 above-described bare-earth modeling, ZVI analyses at significant or important scenic resources
15 identified within the analysis area. Proposed facility components would be located in an upland
16 area situated between the canyons of Buck Hollow Creek to the north and east and the
17 Bakeoven Creek system to the south. Elevations reach approximately 2,700 feet just beyond the
18 southern edge of the proposed site boundary and gradually decrease toward the northwest,
19 with typical elevations declining to about 2,300 feet near the western edge of the solar arrays
20 and Bakeoven Substation and to 1,800 feet at Maupin Substation. Low ridges to the
21 east of Hauser Canyon (a tributary of Buck Hollow) and slightly higher terrain to the southwest
22 and north of the proposed site boundary effectively limit potential visibility of proposed solar
23 facility components, not including the 230 kV transmission line, in most areas that are beyond 3
24 or 3 miles of the site.10
25
26 As presented in Table 7: Important Scenic Resources, Distance from Proposed Site Boundary and
27 Potential Visibility of Proposed Facility Components, there is no potential visibility of proposed
28 facility components from the following identified important or significant scenic resources
29 within the analysis area: White River Canyon, US 97 (MP 48.81 – 56.04), OR 216 (MP 6.00 –
30 8.30, 8.30 – 11.00), or 218 (0.56 – 7.31). As presented below, the Department presents its
31 analysis of the applicant’s visual impact assessment for the important or significant scenic
32 resources where potential visibility of proposed facility structures was identified.
33

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Table 7: Important Scenic Resources, Distance from Proposed Site Boundary and
Potential Visibility of Proposed Facility Components

<table>
<thead>
<tr>
<th>Important Scenic Resource</th>
<th>Distance From Proposed Site Boundary</th>
<th>Visibility Assessment of Proposed Facility Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deschutes River Canyon</td>
<td>2.5</td>
<td>Transmission line</td>
</tr>
<tr>
<td>Wasco County</td>
<td>5</td>
<td>Transmission line</td>
</tr>
<tr>
<td>Sherman County</td>
<td>3</td>
<td>No visibility</td>
</tr>
<tr>
<td>White River Canyon</td>
<td>3</td>
<td>No visibility</td>
</tr>
</tbody>
</table>

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Designated significant or important scenic route segments on US 97 (MPs 30.00 – 48.81, 56.72 – 68.66) would be located approximately 8 miles from the proposed site boundary, where the existing viewed includes expansive views of open terrain. At a distance of 8 to 9 miles, the existing viewed also includes two parallel 500 kV transmission lines that run north-south to interconnect to BPA’s Bakeoven Substation; and, five transmission lines that generally run east-west and north-south interconnecting at BPA’s Maupin Substation. Based on the applicant’s viewed analysis and multiple site visits conducted by the applicant and the Department, the proposed 230 kV transmission line and aboveground 34.5 collector line may be potentially visible from two short segments where the highway runs along a minor drainage divide (MP 62), but from a distance of 9 miles where as described above contains existing transmission infrastructure. Proposed solar facility components may be visible, at distances of 8 miles, from an approximately 0.5 mile route segment that passes through the unincorporated community of Kent; and, for approximately 4 miles extending along the route segment from Bourbon Lane to the northern edge of the analysis area.

As presented in ASC Exhibit R, the applicant represents that the potential change in viewed would include a minimal change in contrast with the current visual context and would not likely be noticeable by viewers travelling on the route segments. Based on evaluation of the applicant’s viewed analysis, existing viewed character, and viewer distance (8 to 9 miles), the Department agrees with the applicant’s conclusions and recommends Council find that the proposed facility would not cause a significant, adverse visual impact to US 97 (MPs 30.00 – 48.81, 56.72 – 68.66).

Designated significant or important scenic route segments on US 197 (MPs 22.42 – 43.83, 47.00 – 50.00) would be located approximately 3 to 4 miles from the proposed site boundary, where the existing viewed includes expansive views of open terrain. The existing viewed also includes two parallel 500 kV transmission lines that run north-south to interconnect to BPA’s Bakeoven Substation; and, five transmission lines that generally run east-west and north-south interconnecting at BPA’s Maupin Substation (see ASC Exhibit C Figure C-3). Notably, two of the existing transmission lines would be closer than proposed facility transmission and collector lines, where one of the existing transmission lines would be located in between the scenic route segment and proposed facility components. Based on the applicant’s viewed analysis, approximately one-third of proposed solar array components may be intermittently visible from most of US 197 (PM 22.42 – 43.83), at a distance of 10 miles. Proposed solar facility components would not be visible from US 197 (47.00 – 50.00). The proposed 230 kV transmission line and aboveground 34.5 collector line may be potentially visible from both US 197 route segments (MPs 22.42 – 43.83, 47.00 – 50.00), at distances ranging from 3 to 10 miles, where the existing viewed contains existing transmission infrastructure.
Based on the foregoing findings of fact, the Department recommends the Council conclude that the design, construction and operation of the proposed facility is not likely to result in significant adverse impacts to any scenic resource, in compliance with Council’s Scenic Resources standard.

IV.K. Historic, Cultural, and Archaeological Resources: OAR 345-022-0090

(1) Except for facilities described in sections (2) and (3), to issue a site certificate, the Council must find that the construction and operation of the facility, taking into account mitigation, are not likely to result in significant adverse impacts to:

(a) Historic, cultural or archaeological resources that have been listed on, or would likely be listed on the National Register of Historic Places;

(b) For a facility on private land, archaeological objects, as defined in ORS 358.905(1)(a), or archaeological sites, as defined in ORS 358.905(1)(c), and

(c) For a facility on public land, archaeological sites, as defined in ORS 358.905(1)(c).

(2) The Council may issue a site certificate for a facility that would produce power from wind, solar or geothermal energy without making the findings described in section (1).

However, the Council may apply the requirements of section (1) to impose conditions on a site certificate issued for such a facility.

Findings of Fact

Section (1) of the Historic, Cultural and Archaeological Resources standard generally requires the Council to find that a proposed facility is not likely to result in significant adverse impacts to identified historic, cultural, or archaeological resources. Under Section (2), the Council may issue a site certificate for a solar power facility without making findings of compliance with this section. However, the Council may impose site certificate conditions based on the requirements of this standard.58

Results of Discovery Measures – Historic and Cultural Resources; Archaeological Sites

58 The site boundary does not encompass public lands; therefore, OAR 345-022-0090(1)(c) is not applicable.
The desktop survey identified 5 previously recorded cultural resources within 1-mile of the analysis area, none of which were recorded within the analysis area. Eighteen archeological sites, including two with historic built components, and 22 isolates were identified within the analysis area. Based on the definition under ORS 358.905(1)(a), the applicant asserts that none of the identified 22 isolates meet the definition of an archeological object. There were no tribally identified within the analysis area. The summary of archeological sites and isolates identified within the analysis area is presented in Table B: Archeological Resources within the Analysis Area and Distance to Proposed Facility Components below.

### Table B: Archeological Resources within the Analysis Area and Distance to Proposed Facility Components

<table>
<thead>
<tr>
<th>Archeological Site</th>
<th>Resource Description</th>
<th>Resource No.</th>
<th>NRHP Eligibility</th>
<th>Distance to Nearest Proposed Facility Component (feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Homestead</td>
<td>18-344-001</td>
<td>Not eligible (A-D)</td>
<td>2,035</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-002</td>
<td>Likely Eligible - Unevaluated (D)</td>
<td>1,012</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-003</td>
<td>Not eligible (A-D)</td>
<td>1,354</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-004</td>
<td>Not eligible (A-D)</td>
<td>789</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-005</td>
<td>Not eligible (A-D)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-006</td>
<td>Not eligible (A-D)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-007</td>
<td>Not eligible (A-D)</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-008</td>
<td>Likely Eligible - Unevaluated (D)</td>
<td>98</td>
<td></td>
</tr>
<tr>
<td>Historically Route and Check Dam</td>
<td>18-344-009</td>
<td>Not eligible (A-D)</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Refuse Scatter</td>
<td>18-344-010</td>
<td>Not eligible (A-D)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Refuse Scatter</td>
<td>18-344-011</td>
<td>Not eligible (A-D)</td>
<td>123</td>
<td></td>
</tr>
<tr>
<td>Refuse Scatter</td>
<td>18-344-012</td>
<td>Not eligible (A-D)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Refuse Scatter</td>
<td>18-344-013</td>
<td>Not eligible (A-D)</td>
<td>123</td>
<td></td>
</tr>
<tr>
<td>Homestead</td>
<td>18-344-014</td>
<td>Likely Eligible - Unevaluated (D)</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Refuse Scatter</td>
<td>18-344-015</td>
<td>Not eligible (A-D)</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

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45 ORS 358.905(1)(a) defines, "archeological object" as, "an object that is at least 75 years old; is part of the physical record of an indigenous or other culture found in the state or waters of the state; and is material remains of past human life or activity that are of archeological significance including, but not limited to, monuments, symbols, tools, facilities, technological by-products and dietary by-products."

46 SHPO’s Guidelines for Conducting Field Archaeology in Oregon (2016) define an isolate as, "Any precontact or historic artifact occurrence that does not qualify for a site designation (i.e. less than nine [9] artifacts)."

47 BAKEAPP-19 Exhibit 5, 2019-13-04. The applicant describes that a rock shelter of indeterminate age (Site 18-344-004) was of particular concern and interest to CTWSRO during a 2019 site visit; however, it was not identified as a tribal resource or Historic Property of Religious and Cultural Significance to Indian Tribes.
Table 8: Archeological Resources within the Analysis Area and Distance to Proposed Facility Components

<table>
<thead>
<tr>
<th>Resource Description</th>
<th>Resource No.</th>
<th>NRHP Eligibility1,2</th>
<th>Distance to Nearest Proposed Facility Component (Feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood and ferrous metal wagon frame</td>
<td>SY18</td>
<td>Not eligible (A-D)</td>
<td>137</td>
</tr>
<tr>
<td>Horse-drawn “Olive” brand weeder</td>
<td>SY22</td>
<td>Not eligible (A-D)</td>
<td>510</td>
</tr>
</tbody>
</table>

Notes:
1. NRHP eligibility determination is based on recommendation by applicant’s consultant, PaleoWest, and confirmed by the Department’s third-party contractor, Historical Research Associates, Inc.
2. The following are a summary of the criteria A-D used to evaluate NRHP eligibility in addition to evaluating the integrity of location, design, setting, materials, craftsmanship, feeling, and association:
   A. The property must be associated with events that have made a significant contribution to the broad patterns of our history.
   B. The property must be associated with the lives of persons significant in our past.
   C. The property must embody the distinctive characteristics of a type, period, or method of construction, represent the work of a master, possess high artistic values, or represent a significant and distinguishable entity whose components may lack individual distinction.
   D. The property must show, or may be likely to yield, information important to history or prehistory.

1 National Registry of Historic Places – Eligibility Status

2 A confidential Archeology and Built Environment Report was submitted, with ASC Exhibit S, in May and, as revised in November 2019, to SHPO for review of the resources identified and NRHP eligibility recommendations, as presented in Table 5: Archeological Resources within the Analysis Area and Distance to Proposed Facility Components. Based on review of the May 2019 report and exhibit, SHPO’s Assistant State Archeologist John Pouley provided comments on the technical information and requested additional information on the NRHP eligibility criteria for the isolates identified within the site boundary. In November 2019, the applicant revised and re-submitted the report for SHPO review. To support SHPO and the Department in technical review of ASC Exhibit S and technical reports, as authorized under ORS 469.470(6) (In October 2018) the Council appointed Golder and its sub-consultant – Historical Research Associates, Inc (HRA). HRA reviewed the May and November 2019 technical reports and, in September and December 2019, provided their recommendations to the Department and SHPO (see Attachment B of this order). Their recommendations concurred with the NRHP eligibility determinations as presented in the table above, which were based on review of the updated analysis provided by the applicant in response to SHPO’s recommendations for further analysis of NRHP eligibility criteria for isolates.

3 As presented in Table 5: Archeological Resources within the Analysis Area and Distance to Proposed Facility Components, there are four identified archeological sites that could not be properly evaluated under NRHP criteria D, and therefore, are conservatively evaluated as likely eligible for NRHP listing. These resources are further described below.

4 Site 18-344-002

5 Site 18-344-002 is an archeological site described as the remains of a historic homestead. The site has multiple features and an artifact concentration located on the eastern end of Little Dog Canyon. The site is an open field with four features: three building foundations and one refuse scatter. Based on site access restrictions, the applicant was unable to properly evaluate NRHP eligibility criteria D and therefore assumes that this site is likely eligible for NRHP listing.

6 Site 18-344-008

7 Site 18-344-008 is an archeological site described as a newly recorded historic-period homestead site composed of artifact concentration and 12 features. The features include: a dwelling, a barn, a root cellar, a possible foundation, a possible foundation or wall alignment, a horse-drawn plow, a fenceline with rock cairn support fence posts, three check dams, and a wall alignment along the drainage likely to manage water flow. Based on site access restrictions, the applicant was unable to properly evaluate NRHP eligibility criteria D and therefore assumes that this site is likely eligible for NRHP listing.

8 Site 18-344-044

9 Site 18-344-044 is an archeological site described as a newly recorded rockshelter of unknown age. The site may represent precontact, historic, or modern use. Based on site access restrictions, the applicant was unable to properly evaluate NRHP eligibility criteria D and therefore assumes that this site is likely eligible for NRHP listing.

10 Site 18-344-014

11 Site 18-344-0014 is an archeological site described as a newly recorded historic-period homestead site and artifact concentration. The features include: a house, barn, large tractor wheel and axle, and a concrete cistern. Based on site access restrictions, the applicant was unable to properly evaluate NRHP eligibility criteria D and therefore assumes that this site is likely eligible for NRHP listing.

12 Potential Impacts to Archeological Sites

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Bakeoven Solar Project - Draft Proposed Order on Application for Site Certificate
January 17, 2020
4846-6947-5766v.1 0108111-000002
Potential impacts are evaluated for the four archeological sites listed above (18-344-002, 18-344-008, 18-344-014, 18-344-044) as likely eligible for NRHP listing. Potential impacts include direct and indirect impacts. Direct impacts could include temporary and permanent disturbance to the resource; indirect impacts could include impacts from facility noise and visual quality to the resource. Indirect impacts could include impacts to physical damage, and that the integrity of the resource is integrity aspects include location, setting, design, materials, craftsmanship, feeling, and association. However, the applicant asserts, and based on HRA's review the Department agrees, that based on the type and characteristics of archeological sites identified, potential impacts would be specific to physical damage, and that the integrity of the archeological sites would not likely be impacted by the viability or proximity to the proposed facility.

In ASC Exhibit 5, the applicant commits to designing the proposed facility to avoid the four archeological sites (18-344-002, 18-344-008, 18-344-014, 18-344-044) and would impose a 20-meter avoidance buffer from all construction activities. In addition, the applicant commits to implementing an Inadvertent Discovery Plan and Worker Environmental Awareness Training to minimize potential impacts to unknown resources, if discovered during construction activities. Therefore, the Department recommends Council impose the following condition requirements during construction:

**Recommended Historic, Cultural, and Archeological Condition 1:** The certificate holder shall:

1. Prior to construction of the facility or any phase of the facility, finalize the draft Inadvertent Discovery Plan, as provided in Attachment 1 of the Final Order on ASC, based on review and concurrence from the Department, in consultation with SHPO or the Department’s third-party contractor.
2. During construction of the facility or any phase of the facility, require all on-site personnel to complete a Worker Environmental Awareness Training provided by a qualified archeologist as defined in OAR 736-051-0070 to properly identify sensitive historic, cultural and archeological resources that could be inadvertently uncovered during construction, and on measures to avoid accidental damage to such resources.
3. Records of all trainings shall be maintained onsite during construction.
4. During construction of the facility or any phase of the facility, ensure its contractors utilize constraint maps and design facility components to adhere to a 20-meter avoidance buffer for archeological resources 18-344-002, 18-344-008, 18-344-014, 18-344-044. Constraint maps shall also identify the entirety of the areas not included in the pedestrian level ground surveys, if outside of the 20-meter avoidance buffer area, and shall preclude placement of facility components or disturbance impacts unless appropriate field surveys are conducted.
5. During construction and operation of the facility or any phase of the facility, the certificate holder shall implement and adhere to the requirements of the Inadvertent Discovery Plan, as reviewed and finalized per sub(a) of this condition.

**Conclusions of Law**

Based on the foregoing recommended findings of fact and conclusions of law, and based upon compliance with the recommended conditions, the Department recommends Council find that the proposed facility would comply with the Council’s Historic, Cultural, and Archeological Resources standard.

**IV.L. Recreation: OAR 345-022-0100**

1. Except for facilities described in section (2), to issue a site certificate, the Council must find that the design, construction and operation of a facility, taking into account mitigation, are not likely to result in a significant adverse impact to important recreational opportunities in the analysis area as described in the project order. The Council shall consider the following factors in judging the importance of a recreational opportunity:

   a. Any special designation or management of the location;
   b. The degree of demand;
   c. Outstanding or unusual qualities;
   d. Availability or rarity;
   e. Irreplaceability or irretrievability of the opportunity.

**Findings of Fact**

The Recreation standard requires the Council to find that the design, construction, and operation of a facility would not likely result in significant adverse impacts to “important” recreational opportunities. Therefore, the Council’s Recreation standard applies only to those recreation areas that the Council finds to be “important,” utilizing the factors listed in the subparagraphs of section (1) of the standard. The importance of recreational opportunities is assessed based on five factors outlined in the standard: special designation or management, degree of demand, outstanding or unusual qualities, availability or rarity, and irreplaceability or irretrievability of the recreational opportunity.

The applicant evaluates impacts to important recreational opportunities based on the potential construction or operation of the proposed facility to result in any of the following: direct or indirect loss of a recreational opportunity, excessive noise, increased traffic, and visual impacts of facility structures or plumes. ASC Exhibit T provides information about recreational opportunities.
opportunities. The analysis area for the Recreation standard is the area within and extending
five miles from the site boundary.

To analyze the proposed facility against this standard, the Council must first evaluate whether
an identified recreational opportunity is important. The Council must then evaluate whether
the design, construction or operation of the facility could adversely impact the identified
important recreational opportunity. If the proposed facility could adversely impact the
resource, then the Council must consider the significance of the possible impact.

Recreational Opportunities within the Analysis Area

In accordance with OAR 345-001-0010(59)(d), and consistent with the study area boundary, the
analysis area for recreational opportunities is the area within and extending 5 miles from the
proposed amended site boundary. As presented in ASC Exhibit T, the applicant conducted a
review of published and unpublished resources including maps, GIS files, comprehensive plans, parks and recreation plans, park master plans, and internet sites to identify existing recreational
opportunities within the analysis area. Based on this review, 9 recreational opportunities were
identified within the analysis area at distances of 0.2 to 4 miles, as presented in Table 9:

Recreational Opportunities within the Analysis Area and Distance from Proposed Site Boundary

<table>
<thead>
<tr>
<th>Recreational Opportunity</th>
<th>Management or Jurisdiction</th>
<th>Distance from Site Boundary (miles)</th>
<th>Special Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sage Canyon Outfitters</td>
<td>Private</td>
<td>0.2</td>
<td>None</td>
</tr>
<tr>
<td>Sherar’s Falls Bikeway</td>
<td>State - OPRD</td>
<td>2.0</td>
<td>Scenic Bikeway</td>
</tr>
<tr>
<td>Deschutes Wild and Scenic River</td>
<td>Federal - BLM</td>
<td>2.0</td>
<td>Federal Wild and Scenic River</td>
</tr>
<tr>
<td>Oasis Campground</td>
<td>Private</td>
<td>3.3</td>
<td>None</td>
</tr>
<tr>
<td>Deschutes River Campgrounds (Oak Springs, Blue Hole, White River)</td>
<td>Federal - BLM</td>
<td>2.2</td>
<td>N/A</td>
</tr>
<tr>
<td>Maupin City Park</td>
<td>City of Maupin</td>
<td>2.4</td>
<td>N/A</td>
</tr>
<tr>
<td>Oak Springs Fish Hatchery</td>
<td>State - ODFW</td>
<td>2.9</td>
<td>N/A</td>
</tr>
<tr>
<td>White Wild and Scenic River</td>
<td>Federal - BLM</td>
<td>3.1</td>
<td>Federal Wild and Scenic River</td>
</tr>
<tr>
<td>White River Falls State Park</td>
<td>State - OPRD</td>
<td>4.0</td>
<td>The park overlaps areas of a state natural area (Tygh Valley State Natural Area)</td>
</tr>
</tbody>
</table>

Notes:
- OPRD = Oregon Parks and Recreation Department; ODFW = Oregon Department of Fish and Wildlife
- BLM = Bureau of Land Management

Table 9: Recreational Opportunities within the Analysis Area and Distance from Proposed Site Boundary

Under the Council’s Recreation standard, the Council must find that, taking into account
mitigation, the proposed facility is not likely to result in a significant adverse impact to those
identified important recreational opportunities. In ASC Exhibit T, the applicant characterizes 2
recreational opportunities as not important (Sage Canyon Outfitters and Oasis Campground) of
the 9 recreational opportunities as important. Based on the evaluation presented below, the
Department agrees with the applicant’s conclusions related to the two opportunities identified
as not important, but also recommends Council consider the Oak Springs Fish Hatchery not to
be an important recreational opportunity under Council’s Recreation standard. The
Department’s evaluation of the applicant’s recreational opportunity “importance” assessment
is presented below.

Recreational Opportunity Importance Assessment

Sage Canyon Outfitters

As presented in ASC Exhibit T, Sage Canyon Outfitters is a private business that provides
opportunities for upland bird hunting, guided and non-guided hunting trips and lodging, located
approximately 0.2-of-a-mile from the proposed site boundary. Sage Canyon Outfitters is not
covered under a state or local management plan, and has no special designation. The applicant
describes the demand for opportunities at Sage Canyon Outfitters to be low, and confirms that
because there are other hunting opportunities within the area, the opportunity at this resource
is not considered rare and would be replaceable. For all of these reasons, the Department
agrees with the applicant’s conclusions and recommends Council find this recreational
opportunity not to be “important” under the Council’s standard.

Sherar’s Falls Bikeway

As presented in ASC Exhibit T, Sherar’s Falls Scenic Bikeway is a 33-mile bikeway route
designated by the Oregon Parks and Recreation Department as a scenic bikeway. The bikeway
traverses diverse topography through the City of Maupin, along the Deschutes River, passing
tribal fishing sites, a section of the White River, and passing White River Falls State Park. The
bikeway is located approximately 2 miles from the proposed site boundary. The applicant
describes the bikeway as rare due to its special designation as a state scenic bikeway, which is a
relatively new program and few currently designated routes; and, irreplaceable due to the
unique topography and resources, as described, that the bikeway passes. For all of these
reasons, the Department agrees with the applicant’s conclusions and recommends Council find
this recreational opportunity to be “important” under the Council’s standard.

Deschutes Wild and Scenic River

As presented in ASC Exhibit T, the Deschutes Wild and Scenic River is designated as a federal
wild and scenic river, managed by the Bureau of Land Management, located approximately 2
miles from the proposed site boundary. The river provides opportunities for non-motorized
boating (rafting, kayaking), fishing and camping. The applicant describes that recreational opportunities at the river are high in demand, with irreplaceable qualities provided by rafting, kayaking and fishing opportunities. For all of those reasons, the Department agrees with the applicant's conclusions and recommends Council find this recreational opportunity to be "important" under the Council's standard.

As presented in ASC Exhibit T, Oasis Campground is a privately-owned campground, with opportunities for tent and recreational vehicle (RV) camping, located approximately 2.1 miles from the proposed site boundary. The campground is not managed under a state or local plan, and while in high demand during summer and fall seasons, is relatively common in the area and therefore would be replaceable. For all of these reasons, the Department agrees with the applicant's conclusions and recommends Council find this recreational opportunity to be "important" under the Council's standard.

Deschutes River Campgrounds

As presented in ASC exhibit T, Deschutes River Campgrounds, including Oak Springs, Blue Hole and White River, are a series of small campgrounds managed by BLM, which provide camping and day use opportunities with access to the Deschutes River. The applicant describes that the resource is not managed under a state or local plan and would be replaceable given the availability of other campgrounds in the area. However, the applicant asserts that based on the high demand of the campgrounds, and the uniqueness of the location with direct access to the river and small campground size, the resource should be considered important. The Department agrees that because the Deschutes River is important due to its opportunities for fishing and non-boating opportunities, which would be served, in many instances, by the Deschutes River Campgrounds, that the resource be considered "important" under Council's standard due to demand and uniqueness.

As presented in ASC Exhibit T, Maupin City Park is a park located on the eastern bank of the Deschutes River, with opportunities for tent and RV camping, with river access, located approximately 2.4 miles from the proposed site boundary. The park is not managed under a state or local plan; however, it receives a high level of user demand during summer and fall, provides amenities not available at other campgrounds, and contains highest campsite capacity of other campgrounds within the area. For these reasons, the Department agrees with the applicant's conclusions and recommends Council find this recreational opportunity to be "important" under the Council's standard.

Oak Springs Fish Hatchery

As presented in ASC Exhibit T, the White Wild and Scenic River is a federally designated wild and scenic river, managed by BLM, extending 50 miles through two wilderness areas, to then converge with the Deschutes Wild and Scenic River. The river is located approximately 3.1 miles from the proposed site boundary. Recreational opportunities include photography, camping, rugged hiking, and nature and wildlife observation. The applicant identifies that the user demand for the resource is low/moderate and irreplaceable recreational opportunities, given the degree of solitude afforded by the location. Due to the special designation under a state management plan as a wild and scenic river with multiple recreational opportunities with a unique degree of solitude, the Department agrees with the applicant's conclusions and recommends Council find this recreational opportunity to be "important" under the Council's standard.

White River Falls State Park

As presented in ASC Exhibit T, White River Falls State Park is a state park managed by OPRD, which provides opportunities for picnicking, hiking and fishing, located approximately 4 miles from the proposed site boundary. Unique aspects of the park include dramatic viewpoints of the White River and a trail to the historic hydroelectric power plant located at the base of the falls. The applicant identifies that user demand of this resource is moderate and given the general opportunities – picnicking and hiking – would be replaceable. However, based on its designation as a state park and unique location along the White River, the Department agrees with the applicant's conclusions and recommends Council find this recreational opportunity to be "important" under the Council's standard.

Potential Direct or Indirect Loss of Recreational Opportunity

As presented in ASC Exhibit T, Oak Springs Fish Hatchery includes opportunities for birdwatching and picnicking and includes a fountain and show pond, located approximately 2.9 miles from the proposed site boundary. The resource is a state-designated fish hatchery, managed by ODFW, but is not specially designated under a state or local plan as a recreational resource. The applicant identifies user demand of the fish hatchery as low and recreational opportunities, bird watching and picnicking, to be replaceable. The applicant identifies the fish hatchery as important due to the fact that it is rare, given lack of any other fish hatchery in the analysis area. However, for this resource, because it does not have a special designation as a recreational resource under a state or local plan, has low demand, with recreational opportunities that would be replaceable within the area, the Department recommends Council find that the fish hatchery not be considered an "important" recreational opportunity under Council's standard. It is noted, that state designated fish hatcheries are evaluated under the Council's Protected Areas standard in Section IV.F. Protected Areas of this order, which includes an evaluation of potential impacts from the proposed facility at Oak Springs Fish Hatchery (where no impacts are anticipated).
Direct Loss

A direct loss to an important recreational opportunity would occur when construction or operation of the proposed facility would impact a recreational opportunity by directly altering the resource so that it no longer exists in its current state. Based on the location of the proposed facility in relation to the six identified important recreational opportunities, as presented in Table 9: Recreational Opportunities within the Analysis Area and Distance from Proposed Site Boundary, ranging from 2 to 9 miles, the proposed facility would not physically disturb or result in ground disturbance, to those recreational opportunities. The proposed facility would also not require any temporary or permanent closure or removal of the important recreation opportunities to public use. Therefore, based upon review of the location and proximity of important recreational opportunities to the proposed facility site, the Department recommends the Council find that the proposed facility would not be expected to result in indirect impacts to the important recreational opportunities.

Indirect Loss

Similar to the assessment of direct loss, indirect loss would result if construction or operation of the proposed facility would impact a recreational opportunity by indirectly altering the resource or some component of it. To evaluate indirect loss associated resulting from the construction and operation of the proposed facility, the Department considers potential noise, traffic and visual impacts to the above mentioned important recreational opportunities.

Potential Noise Impacts

The significance of potential noise impacts to identified protected areas is based on the magnitude and likelihood of the impact on the affected human population or natural resources that uses the important recreational opportunity. The nearest important recreational opportunity to the proposed site boundary is Sherar’s Falls Scenic Bikeway, located approximately 2.0 miles from the proposed site boundary. Potential noise impacts from proposed facility construction and operation are evaluated below.

Construction

As evaluated in the ASC Exhibit X, construction-related noise impacts are based on equipment sound levels as provided in the 2006 Federal Highway Administration Roadway Construction Noise Model. Proposed facility construction would include site preparation, grading, preparation of staging areas and onsite access routes; array foundation installation, conductor installation, and construction of collector substation; solar panel assembly and construction of electrical components; inverter pad construction; commissioning of solar array and interconnection; installation of transmission structure foundations; erection of support structures; and, conductor stringing.

Exhibit X, construction of transmission structure foundations; erection of support structures; and, conductor stringing.

Noise Model. Proposed facility construction would include site preparation, grading, preparation of staging areas and onsite access routes; array foundation installation, conductor installation, and construction of collector substation; solar panel assembly and construction of electrical components; inverter pad construction; commissioning of solar array and interconnection; installation of transmission structure foundations; erection of support structures; and, conductor stringing.

Similar to the assessment of direct loss, indirect loss would result if construction or operation of the proposed facility would impact a recreational opportunity by indirectly altering the resource or some component of it. To evaluate indirect loss associated resulting from the construction and operation of the proposed facility, the Department considers potential noise, traffic and visual impacts to the above mentioned important recreational opportunities.

Potential Noise Impacts

The significance of potential noise impacts to identified protected areas is based on the magnitude and likelihood of the impact on the affected human population or natural resources that uses the important recreational opportunity. The nearest important recreational opportunity to the proposed site boundary is Sherar’s Falls Scenic Bikeway, located approximately 2.0 miles from the proposed site boundary. Potential noise impacts from proposed facility construction and operation are evaluated below.

Operation

Proposed facility components that would generate noise during operations include: transformers and inverters associated with the solar arrays, inverters and cooling systems associated with battery storage systems; and, corona discharge noise (buzz or crackling during wet conditions) from the 230 kV transmission line. In ASC Exhibit X, the applicant provides a noise analysis inclusive of the operational sources and sound power levels (in A-weighted decibels) for proposed facility components, as listed below.

1. Inverters, each at 88 dBA
2. Distribution transformers, each at 77 dBA
3. Substation transformers at 106 dBA
4. Battery storage heating, ventilation and air conditioning units, each at 89 dBA
5. Battery storage transformers, each at 77 dBA
6. 230 kV transmission line at 76 to 99 dBA (fair to rainy conditions)

As presented in ASC Exhibit X, statistical noise modeling results indicate that maximum operational noise levels of the proposed facility would range between 20 to 25 dBA within 1-mile of the proposed facility, which would be extremely quiet. Based on ANISOA guidelines, noise levels of 43 to 48 dBA would be considered extremely quiet, and expected at no more than 1% of the population. In ASC Exhibit X, the nearest important recreational opportunity to proposed facility components would be at a distance of 2-miles; the Department recommends


10 Based on review of the applicant’s construction-related noise impact assessment, as described above, the Department recommends that Council find that proposed facility construction would not result in noise impacts at Sherar’s Falls Scenic Bikeway. Because the other important recreational opportunities within the analysis area are located at greater distances from the proposed site boundary than the scenic bikeway, the Department recommends that Council find that there would be no impacts from proposed facility construction noise at the other important recreational opportunities.

11 Based on review of the applicant’s construction-related noise impact assessment, as described above, the Department recommends that Council find that proposed facility construction would not result in noise impacts at Sherar’s Falls Scenic Bikeway. Because the other important recreational opportunities within the analysis area are located at greater distances from the proposed site boundary than the scenic bikeway, the Department recommends that Council find that there would be no impacts from proposed facility construction noise at the other important recreational opportunities.

12 Based on review of the applicant’s construction-related noise impact assessment, as described above, the Department recommends that Council find that proposed facility construction would not result in noise impacts at Sherar’s Falls Scenic Bikeway. Because the other important recreational opportunities within the analysis area are located at greater distances from the proposed site boundary than the scenic bikeway, the Department recommends that Council find that there would be no impacts from proposed facility construction noise at the other important recreational opportunities.
Council find that operational noise from the proposed facility would not impact any important recreational opportunities within the analysis area.

Traffic Impacts

Proposed facility construction would result in up to 750 average daily trips (ADT) (including worker vehicles, pick-up trucks, material delivery vehicles) on I-84 and Bakeoven Road, 364 ADTs on US 197, 92 ADTs on US 97 (north, part of alternate route), and 46 ADTs on US 97 (south, workforce-only). Access to Sherar’s Falls Scenic Bikeway and Deschutes River Federal Wild and Scenic River is provided by Deschutes River Road (also known as Lower Deschutes River Back County Byway), which is fed by US 197 and Bakeoven Road. As presented in ASC Exhibit L and T, based upon potential construction-related traffic, access to the Deschutes River and Sherar’s Falls Scenic Bikeway may be impacted by intermittent short-term traffic delays.

The applicant proposes several best management practices, as presented in Attachment M of this order and represented below, in addition to developing a Construction Traffic Management Plan in coordination with the City of Maupin, Wasco County Public Works Department, BLM, and Sherar’s Falls Scenic Bikeway and Wasco County Public Services Condition 3).

- Complete consultation with landowners to minimize disruptions to ranching and farming operations due to construction activities such as equipment delivery whenever possible when slow or oversized loads are being hauled;
- Implement traffic-diversion equipment (such as advance signage and pilot cars) to minimize risk of accidents. Flag persons may facilitate two-way traffic on one lane by alternately restricting travel directions. This method would not require full lane closures, detours, or reroutes. Flag persons would also monitor traffic on public roads as necessary so that they are not in conflict with construction vehicles.
- Maintain at least one travel lane at all times so that roadways would not be closed to traffic due to construction vehicles entering or exiting public roads.
- Avoid peak traffic times identified through consultation with Wasco County and the City of Maupin by adjusting scheduling of workforce shifts or other methods, such as requiring construction workers to check for congestion prior to leaving for the Facility to consider an alternate route.
- Conduct awareness training for all construction workforce drivers, including appropriate techniques for sharing roads with recreation users (especially cyclists and during peak tourist season mid-June through early September) and proper navigation of tight curves.
- Potential traffic impacts during proposed facility construction would be intermittent and temporary, and traffic levels would return to normal following construction.

During operations, the proposed facility would generate an additional 5 to 10 one-way trips on existing local roads. Based on the minimal number of operational trips, the Department agrees with the applicant that the increase would not be likely to have any impact on important recreational opportunities, including access points.1)

- Based on review of the applicant’s analysis and proposed BMPs, the Department agrees with the applicant’s conclusions and recommends Council find that potential traffic-related impacts during construction and operation of the proposed facility would not likely result in significant adverse impacts to any important recreational opportunity.

Potential Visual Impacts

The applicant conducted a zone of visual influence (ZVI) analysis to determine if the proposed facility components could be seen from important recreational opportunities within the analysis area. A detailed discussion of the methodology and visual assessment approach is provided in Section IV.J., Scenic Resources, of this order. The ZVI analysis methodology and overall visual impact assessment approach were the same for recreational opportunities, protected areas, and scenic resources. The result of the ZVI analysis is provided in ASC Exhibit T, Figure T-2, which represents that proposed facility components would be potentially visible at 2 important recreational opportunities identified within the analysis area, including the Deschutes Federal Wild and Scenic River and Sherar’s Falls Scenic Bikeway. Potential visibility impacts of proposed facility components at these two important recreational opportunities is evaluated below.

Deschutes Federal Wild and Scenic River

The Deschutes River would be 2.5 to 5 miles from the proposed site boundary, where the existing viewed includes BPA’s existing Maupin Substation, a railroad, roads, and urbanized development in the City of Maupin. Based on the applicant’s viewed analysis and multiple site visits conducted by the applicant and the Department, views of proposed solar facility components, not including the proposed 230 kV transmission line, would be blocked entirely by canyon terrain. The proposed 230 kV transmission line, though, may be intermittently visible from elevated points on the canyon walls above river level, on Deschutes River Road (where viewers are unlikely to be present). Based on the applicant’s viewed analysis, potential visibility of the proposed 230 kV transmission line would be limited to elevated canyon locations – and would not be visible from parts of the river considered to be the significant or important scenic resource. Nonetheless, the applicant describes the potential impact of the change in viewed from the elevated points along canyon walls and indicates that it would create a minimal change in contrast with the current visual context and would be seen by few, if any, viewers. Therefore, based on the applicant’s viewed analysis, existing viewed character, distance (2.5 to 5 miles) and elevation change from the river to the proposed 230 kV transmission line (1,345 compared to 2,300 feet), the Department recommends Council find

1) See Section IV.M, Public Services of this order for further discussion of traffic impacts.
that the proposed facility would not cause a significant, adverse visual impact to the Deschutes River.

Sherar’s Falls Scenic Bikeway

Sherar’s Falls Scenic Bikeway would be 2 miles from the proposed site boundary, where the existing viewed also includes BPA’s existing Maupin Substation, a railroad, roads, and urbanized development in the City of Maupin. Based on the applicant’s view shed assessment, less than one-third of the proposed solar array and portions of the 34.5 kV and 230 kV transmission lines may be visible along the western and southern sides of the bikeway, along OR 216 and US 197.

The applicant suggests that based on viewing distance, topography of the area, and existing visual character, the potential change in viewed contrast from potential visibility of proposed facility component would be minimal, which the Department agrees. Based on this reasoning and analysis, supported by the visual impact assessment, the Department recommends Council find that the proposed facility would not cause a significant, adverse visual impact to the bikeway.

Conclusions of Law

Based on the foregoing recommended findings of fact, the Department recommends that the Council find that the design, construction and operation of the proposed facility are not likely to result in a significant adverse impact to any important recreational opportunities in the analysis area and therefore the proposed facility would comply with the Council’s Recreation standard.

IV.M Public Services: OAR 345-022-0110

(1) Except for facilities described in sections (2) and (3), to issue a site certificate, the Council must find that the construction and operation of the facility, taking into account mitigation, are not likely to result in significant adverse impact to the ability of public and private providers within the area described in the project order to provide: sewers and sewage treatment, water, storm water drainage, solid waste management, housing, traffic safety, police and fire protection, health care and schools.

(2) The Council may issue a site certificate for a facility that would produce power from wind, solar or geothermal energy without making the findings described in section (1). However, the Council may apply the requirements of section (1) to impose conditions on a site certificate issued for such a facility.

Footnote:
OAR 345-022-0110(1) does not apply to this ISC because the proposed facility would not meet the criteria for a special criteria facility as defined in ORS 499.373(1).

Findings of Fact

The Council’s Public Services standard requires the Council to find that the proposed facility is not likely to result in significant adverse impacts on the ability of public and private service providers to supply sewer and sewage treatment, water, stormwater drainage, solid waste management, housing, traffic safety, police and fire protection, health care, and schools.

Pursuant to OAR 345-022-0110(2), the Council may issue a site certificate for a facility that would produce power from solar energy without making findings regarding the Public Services standard; however, the Council may impose site certificate conditions based upon the requirements of the standard.

The analysis area for potential impacts to public services from construction and operation of the proposed facility is the area within and extending 10 miles from the site boundary.

Information about construction phasing and potential impacts to public service providers can be found in ASC Exhibit B and U.

Important Assumptions used in Applicant’s Impact Assessment

Important assumptions relied upon by the applicant to evaluate potential impacts from proposed facility construction and operation to private and public providers include number of workers needed, population shifts and use of transportation routes.

Proposed facility construction is anticipated to commence in 2020 and be completed by 2025, with construction potentially occurring in multiple 9 to 12 month phases. The construction workforce is estimated at 250 workers on average, with a peak of 400 workers. Construction-related vehicle trips per day, per phase, are assumed to include 630 truck trips per day (315 roundtrips), with a peak of 750 trips (375 roundtrips), which accounts for a carpool factor of 2 persons per vehicle for survey crews and 1.5 persons per vehicle for all other categories.

Interstate Highway 84 (I-84), U.S. Highway (US) 197 near The Dalles, and Bakeoven Road are identified as the primary transportation routes during proposed facility construction. Additional routes that could be used during proposed facility construction include I-84 to US 97 (Sherman Highway) at Biggs Junction, southbound through the town of Shaniko and US 97 north/northeast to Bakeoven Road. Potential impacts to transportation routes are based on an assumption that 70 percent of the workforce traffic would use the primary route, 20 percent would use the alternate transporter route, and 10 percent would use US 97 north to Bakeoven Road.

The applicant assumes that 30 percent of the construction workforce would represent local residents (Wasco Sherman, Gilliam, Wheeler and Jefferson counties), and the remainder of workers hired from outside the surrounding four-county area. Based on this assumption, population shifts would include an average of 175 workers, and then adjusted for average household size, to 560 temporary residents during proposed facility construction.
The applicant states that it would obtain water for construction activities from the City of Maupin’s existing water right, and provides a copy of written correspondence with the City of Maupin confirming adequate capacity to cumulatively provide sufficient water supply for facility construction. The applicant proposes to supply water for operations from an existing or newly constructed water permit exempt well; or, if a well is installed and used for construction water under a limited water use license obtained by a third-party contractor, that well may be used during facility operation, but used under exempt groundwater purposes. As discussed in Section IV.Q.3, Water Rights of this order, an onsite well drawing less than 5,000 gallons per day does not require a water right permit, but a usage log must be maintained in accordance with ORS 537.765. To ensure compliance with statutory and public service provider requirements, the Department recommends the following condition:

Recommended Public Services Condition 2: During facility operation, the certificate holder shall ensure that if a permit exempt well is constructed to provide water to the O&M building, the certificate holder shall maintain a usage log in accordance with ORS 537.765. The certificate holder shall not use more than 5,000 gallons of water per day from the onsite well. The certificate holder may use other sources of water for onsite uses subject to approval by the Department.

Bakeoven Solar Project - Draft Proposed Order on Application for Site Certificate
January 17, 2020
4846-6947-576v.1 0108111-000002

Oregon Department of Energy
Proposed facility construction, operation and decommissioning would result in solid waste generation. Proposed facility construction would generate approximately 4,000 to 7,000 cubic yards of solid waste, total, including discarded construction materials, packaging materials, spent erosion control materials, wood form work, scrap metal from damaged pilings or racking equipment, or unused wiring. Construction waste would be stored in onsite debris bins, including separate bins for hazardous and non-hazardous materials. Materials suitable for recycle include some packaging materials, metals, glass, paper, wood and concrete, which the applicant commits to recycling to the extent possible. Remaining hazardous (i.e. oily rags) and non-hazardous waste would be managed by a local solid waste hauler and disposed of at a licensed facility. The applicant’s proposed measures for minimizing construction-related solid waste include: detailed material estimating and efficient construction practices.

Solid waste generated during proposed facility operation would include approximately 6 yards of office waste from the O&M building; and, damaged or defective solar panels, batteries, and other electrical equipment, which is expected to be infrequent. All solid waste generated during proposed facility operation would be collected onsite and recycled at licensed facilities, as feasible. Solid waste generated during proposed facility decommissioning would include steel, aluminum, concrete, solar photovoltaic modules, cable, plastics, and battery components. The applicant represents that these materials would be recycled or reused, sold for scrap, or taken to a landfill.

As presented in ASC Exhibit U, the applicant commits to minimizing onsite solid waste through appropriate materials estimating and recycling, to the extent feasible. In addition, to ensure onsite waste is minimized to the extent feasible, the Department recommends Council impose a condition under the Waste Minimization standard (see Section IV.N. Waste Minimization of this order), requiring that the applicant develop and implement a Solid Waste Management Plan during all phases of construction, operation and decommissioning. The applicant also obtained confirmation from the Wasco County Landfill (ASC Exhibit U, Attachment U-2) confirming adequate long-term capacity to meet the proposed facility’s solid waste disposal needs. Therefore, based on the quantity and type of solid waste generated by the proposed facility, compliance with the above-described recommended condition, and the confirmation obtained from the landfill, the Department recommends Council find that the construction and operation of the proposed facility are not likely to result in significant adverse impacts to the ability of solid waste disposal providers to dispose generated waste.

Traffic Safety

Potential impacts from the proposed facility on the ability of public and private providers of traffic safety are based on the volume and weight of vehicles, including worker vehicles and trucks delivering equipment and materials, and the capacity and existing condition of the transportation routes that would be utilized during construction and operation to support the increase in traffic volume and type of use.

As provided in ASC Exhibit U, the applicant contracted with Westwood Surveying and Engineering to develop a Traffic Count Plan (ASC Exhibit U Attachment U-1), which evaluates proposed work tasks, construction equipment and materials, material and equipment delivery vehicles, and the construction schedule to determine a peak daily trip estimate from proposed facility construction. Based on Westwood’s Traffic Count Plan, and the assumptions described above and in ASC Exhibit U, proposed facility construction would result in up to 750 average daily trips (ADT) (including worker vehicles, pick-up trucks, material delivery vehicles) on I-84 and Bakeoven Road, 364 ADTs on US 197, 92 ADTs on US 97 (north, part of alternate route), and 46 ADTs on US 97 (south, workforce-only).

Based on review of Oregon Department of Transportation’s (ODOT) 2017 Traffic Volumes on State Highways, the most recent year evaluated, segments of I-84 carried an ADT volume ranging from 16,700 to 23,600 vehicles between The Dalles and Bigg Junction; segments of US 97 carried an ADT volume ranging from 2,900 to 7,100 vehicles; and segments of US 97 carried an ADT volume ranging from 2,300 to 7,800. Based on the lowest ADT volume recorded in 2017 on the transportation routes to be used during construction and projected peak ADT from proposed facility construction, the increase in traffic volume on I-84 would be approximately 5 percent (750/16,700); increase of approximately 13 percent (364/2,900) on US 197; and, an increase of approximately 4 percent (92/2,300) on US 97. The potential increases in ADT range on the proposed transportation routes range from 4 to 13 percent and would be short-term and temporary in duration.

In ASC Exhibit U, the applicant describes that traffic counts on Bakeoven Road are not available, but that based on review of Wasco County’s 2009 Transportation System Plan, rural major collector roads could be expected to carry 2,000 vehicles per day. Based on projected proposed facility construction-related traffic of 750 ADTs on Bakeoven Road, the potential increase in ADT would be approximately 50 percent or greater, depending on the season.

Existing conditions of proposed transportation routes ranges from fair to very good, with fair conditions described as those with minor or low severity pavement deficiencies that typically lead to treatment such as chip seal or light resurfacing.

To reduce potential impacts to traffic service providers for impacts from proposed facility construction, the Department recommends the Council impose the following condition:

**Recommended Public Services Condition 3:**

a. Prior to construction of the facility or any phase of the facility, the certificate holder shall:
   i. Consult with Wasco County Road Division and ODOT to determine whether any segments of roadway or bridges are restricted for travel, and to obtain any heavy haul permits required to allow transport of these loads.
   ii. Execute a Road Use Agreement with Wasco County Public Works Roads Division to ensure that any unusual damage or wear to state or county roads that is caused by facility construction related traffic and road use is repaired by the certificate holder.
The Road Use Agreements shall establish and provide financial security regarding county road use, maintenance, and repair from construction-related impacts. Regardless of existing pavement conditions, the road use agreements shall establish that roadway segments will be reviewed prior to any added construction traffic, and establish a system for monitoring safety or degradation to pavement prior to and during construction. The certificate holder shall complete a Road Impact Assessment/Geotechnical Report for public roads to be used during construction, pursuant to WCLUDO Section 10.030(C)(9), and shall incorporate the report/results into the Road Use Agreement to identify appropriate improvement and/or level of restoration.

b. Coordinate with local transportation officials to make improvements where necessary to accommodate facility construction traffic, and improvements will be restricted to areas within the respective rights-of-way.

c. Submit to the Department for review in consultation with Wasco County Public Works Roads Division, City of Maupin, DDOT, and Bureau of Land Management a Construction Traffic Management Plan that includes, at a minimum, the best management practices provided in Attachment M of the Final Order on the ASC.

d. During construction of any phase of the facility, the certificate holder shall implement the Construction Traffic Management Plan, as approved by the Department under sub(a)(iv) of this condition.

Based on compliance with the above-referenced condition, and the temporary nature of potential construction-related impacts, the Department recommends Council find that the construction and operation of the proposed facility are not likely to result in significant adverse impacts to the ability of transportation providers to provide traffic safety.

Police and Fire Protection

As presented in ASC Exhibit U, police protection services are provided by most of the incorporated cities within the 20-mile analysis area, with backup law enforcement available from the Oregon State Police Central Region, with offices in Madras, The Dalles, Government Camp, and Prineville.

Proposed facility construction could result in increased demand of police protection services due to the increase in onsite temporary workers and new activity at the proposed site. The applicant provides that onsite protection from crime or vandalism would be minimized through its onsite security and commits to maintaining good communications between onsite security personnel and the Wasco County Sheriff’s Office. The applicant also provides, as evidence, a letter from Wasco County Sheriff’s Office (ASC Exhibit U-F), confirming that the county would not consider the proposed activities or increase in temporary workers to create excessive demand on its providers. Proposed facility operation would be secured from crime or vandalism, which could increase demand of local police protection providers, through perimeter fencing and locked gates at the proposed substation, O&M building and battery storage system. Based on the applicant’s representation, the Department recommends Council impose the following condition:

Recommended Public Services Condition 4: During construction of the facility or any phase of the facility, the certificate holder shall provide onsite security and maintain good communication between onsite security personnel and the Wasco County Sheriff’s Office.[CON-PS-01]

As presented in ASC Exhibit U, fire protection services within the analysis area include Juniper Flat Rural Fire Protection District and the newly formed Bakeoven-Shaniko Rangeland Fire Protection District, which is a fully-equipped fire district, to implement a Fire Prevention and Emergency Response Plan and provide 24-hour, 7 days a week emergency service to the proposed facility; this commitment is reflected in the Department’s recommended Land Use Condition 7.

The proposed facility could result in increased fire risk within the analysis area during both construction and operation. Construction-related fire risks include accidental grass fires. As reflected in recommended Land Use Condition 7, the applicant commits to minimizing these risks by establishing roads before accessing the site to keep vehicles away from grass, using diesel vehicles whenever possible (to prevent potential ignition by catalytic converters), avoiding idling vehicles in grassy areas, keeping cutting torches and similar equipment away from grass, and development of a health and safety plan.

Operations related fire risk include unanticipated equipment malfunction of lithium-ion batteries and vegetation impacts to high-voltage transmission lines. The applicant proposes to minimize these potential fire risks through facility design, adherence to applicable requirements, and implementation of an Operational Fire Prevention and Emergency Response Plan (provided as Attachment N of this order), as recommended in Land Use Condition 7. As presented in Attachment U, the certificate holder has submitted a Road Impact Analysis with the facility plan (provided as Attachment N of this order), as recommended in Land Use Condition 7.

Recommended Public Service Condition 5: Prior to construction of the facility or any phase of the facility, the certificate holder must coordinate with the Oregon State Fire Marshal’s Office to determine if the facility is compliant with state requirements for a commercial solar energy generation facility. A statement from the Oregon State Fire Marshal’s office demonstrating their concurrence that the facility complies with their requirements shall be provided to the Department and Wasco County Planning Department.[PRE-PS-01]

Based on compliance with the above-recommended conditions, the Department recommends Council find that the construction and operation of the proposed facility are not likely to result in significant adverse impacts to the ability of police protection or fire services providers to provide services.
I address the Council’s Public Services Standard. The Department recommends that the Council include the above referenced conditions in their site certificate to address the Waste Minimization Standard.

Based on the foregoing analysis, and in compliance with OAR 345-022-0022(2), the Council must find that, to the extent reasonably practicable:

(a) The applicant’s solid waste and wastewater plans are likely to minimize generation of solid waste and wastewater in the construction and operation of the proposed facility, and when solid waste or wastewater is generated, to result in recycling and reuse of such wastes;

(b) The applicant’s plans to manage the accumulation, storage, disposal and transportation of waste generated by the construction and operation of the facility are likely to result in minimal adverse impact on surrounding and adjacent areas.

(2) The Council may issue a site certificate for a facility that would produce power from wind, solar or geothermal energy without making the findings described in section (1). However, the Council may apply the requirements of section (1) to impose conditions on a site certificate issued for such a facility.

Findings of Fact

The Waste Minimization Standard requires the Council to find that the applicant would minimize the generation of solid waste and wastewater, and that the waste generated would be managed to minimally impact surrounding and adjacent areas. Pursuant to OAR 345-022-0022(2), the Council may issue a site certificate for a solar facility without making findings regarding the Waste Minimization standard; however, the Council may impose site certificate conditions based upon the requirements of the standard.

Solid Waste

Proposed facility construction, operation and decommissioning would result in solid waste generation. Proposed facility construction would generate approximately 4,000 to 7,000 cubic yards of solid waste, total, including discarded construction materials, packaging materials, spent erosion control materials, wood form work, scrap metal from damaged pilings or racking equipment, or unused wiring. Construction waste would be stored in onsite debris bins, including separate bins for hazardous and non-hazardous materials. Materials suitable for recycle include some packaging materials, metals, glass, paper, wood and concrete, which the applicant commits to recycling to the extent possible. Remaining hazardous (i.e. oily rags) and non-hazardous waste would be managed by a local solid waste hauler and disposed of at a licensed facility. The applicant’s proposed measures for minimizing construction-related solid waste include: detailed material estimating and efficient construction practices.

Solid waste generated during proposed facility operation would include approximately 6 yards of office waste from the O&M building; and, damaged or defective solar panels, batteries, and other electrical equipment, which is expected to be infrequent. All solid waste generated during

Conclusions of Law

(a) Based on the foregoing analysis, and in compliance with OAR 345-022-0110(2), the Department recommends that the Council include the above referenced conditions in the site certificate to address the Council’s Public Services Standard.

IV. Waste Minimization: OAR 345-022-0120

Housing

Proposed facility construction could necessitate temporary housing needs for a maximum of up to 280 households, with an average of 175 new households during any phase of construction, if the facility is constructed in phases. The applicant assumes that 30 percent of construction workers would be hired locally, with the remaining workers representing out of town workers, but that would commute up to 50-miles for temporary housing. Within 50-miles of the proposed facility, the applicant identifies availability of more than 1,000 hotel and motel rooms. The applicant also asserts that based on its industry experience, utility scale energy facilities can be constructed within rural areas without impacted local housing providers, due to the likelihood of workers willing to commute greater distances for temporary housing than the immediate area within City of Maupin, which could be impacted negatively housing needs during construction were served solely by the City of Maupin. Proposed facility operations would result in 5 to 10 permanent employees and would not be expected to impact local providers of housing service. Based on the applicant’s industry experience and availability of temporary housing within a 50-mile radius of the proposed facility, the Department recommends Council find that construction and operation of the proposed facility are not likely to result in significant adverse impacts to the ability of housing providers to provide housing.

Schools and Healthcare

Proposed facility construction could result in increased demand of health care providers. However, due to the relatively small number of new temporary residents and new permanent residents, significant new demands are not expected from health care facilities that serve the area. Therefore, no significant adverse impact on the ability of communities to provide health care is anticipated as a result of proposed facility construction or operation.

Proposed facility construction would not be expected to increase demand of school providers due to the temporary nature of the activity and low likelihood that families would relocate permanently. Due to the relatively small number of new temporary residents and new permanent residents, significant new demands are not expected from schools that serve the area. Therefore, the Department recommends Council find that construction and operation of the proposed facility are not likely to result in significant adverse impacts to the ability of school providers to provide schools.

Findings of Fact

The Waste Minimization Standard requires the Council to find that the applicant would minimize the generation of solid waste and wastewater, and that the waste generated would be managed to minimally impact surrounding and adjacent areas. Pursuant to OAR 345-022-0022(2), the Council may issue a site certificate for a solar facility without making findings regarding the Waste Minimization standard; however, the Council may impose site certificate conditions based upon the requirements of the standard.

Solid Waste

Proposed facility construction, operation and decommissioning would result in solid waste generation. Proposed facility construction would generate approximately 4,000 to 7,000 cubic yards of solid waste, total, including discarded construction materials, packaging materials, spent erosion control materials, wood form work, scrap metal from damaged pilings or racking equipment, or unused wiring. Construction waste would be stored in onsite debris bins, including separate bins for hazardous and non-hazardous materials. Materials suitable for recycle include some packaging materials, metals, glass, paper, wood and concrete, which the applicant commits to recycling to the extent possible. Remaining hazardous (i.e. oily rags) and non-hazardous waste would be managed by a local solid waste hauler and disposed of at a licensed facility. The applicant’s proposed measures for minimizing construction-related solid waste include: detailed material estimating and efficient construction practices.

Solid waste generated during proposed facility operation would include approximately 6 yards of office waste from the O&M building; and, damaged or defective solar panels, batteries, and other electrical equipment, which is expected to be infrequent. All solid waste generated during
proposed facility operation would be collected onsite and recycled at licensed facilities, as
feasible. Solid waste generated during proposed facility decommissioning would include steel,
aluminum, concrete, solar photovoltaic modules, cable, plastics, and battery components. The
applicant represents that these materials would be recycled or reused, sold for scrap, or taken
to a landfill.
Based on the applicant’s solid waste minimization measures, the Department recommends
Council impose the following condition:
Recommended Waste Minimization Condition 1: During construction, operation and
decommissioning of the facility or any phase of the facility, the certificate holder shall
develop and implement a Solid Waste Management Plan that includes but is not limited to
the following measures:
e. Recycling steel and other metal scrap
f. Recycling wood waste
g. Recycling packaging wastes such as paper and cardboard
h. Collecting non-recyclable waste for transport to a local landfill by a licensed waste
hauler
i. Segregating all hazardous wastes such as oil, oily rags and oil-absorbent materials,
mercury-containing lights and lead-acid and nickel-cadmium batteries for disposal by a
licensed firm specializing in the proper recycling or disposal of hazardous waste.

Conclusions of Law

Wastewater

Proposed facility construction, operation and decommissioning would result in wastewater
generation. Proposed facility construction would result in sanitary waste from onsite portable
toilets and concrete wash water from concrete trucks, which would be managed to minimize
potential for offsite contamination through the applicant’s NPDES 1200-C permit. Proposed
facility operation would result in minimal sanitary waste (limited to 7,500 gallons based on the
septic system capacity). While proposed facility operations would include solar panel washing
and electrolyte solution replacement, for the battery storage systems, these sources would not
be considered wastewater. Based on the limited sources of wastewater, it would be unlikely for
the surrounding area to be impacted by proposed facility wastewater generation.

Conclusions of Law

Wastewater and compliance with the recommended solid waste management plan condition,
waste would be minimized during proposed facility construction, operation and
decommissioning and therefore the applicant has sufficiently addressed the Council’s Waste
Minimization Standard.

IV. Division 23 Standards

The Division 23 standards apply only to "nongenerating facilities" as defined in ORS
469.503(2)(e)(K), except nongenerating facilities that are related or supporting facilities. The
proposed facility would not be a nongenerating facility as defined in statute and therefore
Division 23 is not applicable.

IV. Division 24 Standards

The Council’s Division 24 standards include specific standards for the siting of energy facilities,
including wind projects, underground gas storage reservoirs, transmission lines, and facilities
that emit carbon dioxide. Because the proposed facility includes an approximately 11-mile 230
kV transmission line, which would transmit energy generated at the site to BPA’s existing
Mauspin Substation, the Council’s Division 24 Siting Standards for Transmission Line standard
applies, as evaluated below.


To issue a site certificate for a facility that includes any transmission line under Council
jurisdiction, the Council must find that the applicant:

(1) Can design, construct and operate the proposed transmission line so that alternating
current electric fields do not exceed 9 kV per meter at one meter above the ground
surface in areas accessible to the public;

(2) Can design, construct and operate the proposed transmission line so that induced
currents resulting from the transmission line and related or supporting facilities will be
as low as reasonably achievable.

Findings of Fact

The Siting Standards for Transmission Lines address issues associated with alternating current
electric fields and induced currents generated by high-voltage transmission lines. OAR 345-024-
0090(1) sets a limit for electric fields from transmission lines of not more than 9 kV per meter at
one meter above the ground surface in areas that are accessible to the public. Section (2)
requires implementation of measures to reduce the risk of induced current. ASC Exhibit AA
provides the applicant’s analysis to support Council’s review of the proposed facility’s
compliance with the standard.

Electric Fields
Electric fields around transmission lines are produced by the presence of an electric charge, measured as voltage, on the energized conductor. Electric field strength is directly proportional to the line's voltage; increased voltage produces a stronger electric field. The strength of the electric field is inversely proportional to the distance from the conductors; the electric field strength declines as the distance from the conductor increases.\(^{1}\)

Peak electrical currents were modeled using the software modeling program, Corona and Field Effects Program (Version 3.1) developed by the Bonneville Power Administration, to analyze electromagnetic fields, measured in units of kilovolts per meter (kV/m), which would be produced by the proposed above-ground 34.5 kV collector line and 230 kV transmission line. As shown in ASC Exhibit AA Table AA-2 and Figure AA-3, the maximum electric field modeled for the proposed 230 kV transmission line is 2.68 kV per meter; and for the proposed 34.5 kV collector lines is 0.756 kV per meter; both of which are below the 9-kV per meter threshold set forth in OAR 345-024-0000X(1).

Based upon review of the applicant's modeling results presented in ASC Exhibit AA, the Department recommends that the Council find that the proposed 230 kV transmission line and 34.5 kV collector lines would not exceed 9 kV per meter at one meter above ground level.

Induced Voltage and Current

The Siting Standards for Transmission Lines requires the Council to find that the applicant "can design, construct and operate the proposed transmission line so that induced currents resulting from the transmission line and related or supporting facilities will be as low as reasonably achievable." Recommended Site Specific Condition 1 [based on the mandatory condition contained in OAR 345-025-0000X(4)], presented in Section IV.A. General Standard of Review requires, in part, the certificate holder to develop and implement a program that provides reasonable assurance that all fences, gates, cattle guards, trailers, or other objects or structures of a permanent nature that could become inadvertently charged with electricity are grounded or bonded throughout the life of the line. To further reduce the risk of induced current and nuisance shocks, the Department recommends the Council adopt the following condition:

**Recommended Siting Standards for Transmission Lines Condition 1:** Prior to operation of the facility, the certificate holder shall provide landowners within 500 feet of the site boundary a map of the 230 kV transmission line and above-ground 34.5 kV collector lines and inform landowners of possible health and safety risks from induced currents caused by electric and magnetic fields. [PRO-TL-01]

\(^{1}\) BSAPPDocket 27 ASC Exhibit AB, p.1. 2019-11-04.

Oregon Department of Energy

**Conclusions of Law**

Based on the foregoing findings of fact and conclusions, and subject to compliance with the recommended site certificate conditions, the Department recommends that the Council find that the proposed facility would comply with the Council’s Siting Standards for Transmission Lines.

**IV.Q. Other Applicable Regulatory Requirements Under Council Jurisdiction**

Under ORS 469.503(3) and under the Council's General Standard of Review (OAR 345-022-0000), the Council must determine whether the proposed facility complies with "all other Oregon statutes and administrative rules...as applicable to the issuance of a site certificate for the proposed facility." This section addresses the applicable Oregon statutes and administrative rules that are not otherwise addressed in Council standards, including noise control regulations, regulations for removal or fill of material affecting waters of the state, and regulations for water rights.

**IV.Q.1. Noise Control Regulation: OAR 340-035-0035**

1. **(1) Standards and Regulations:**

2. **(b) New Noise Sources:**

3. **(B) New Sources Located on Previously Unused Site:**

4. No person owning or controlling a new industrial or commercial noise source located on a previously used industrial or commercial site shall cause or permit the operation of that noise source if the statistical noise level generated by that new source and measured at an appropriate measurement point, specified in subsection (3)(b) of this rule, exceed the levels specified in Table 8, as measured at an appropriate measurement point, as specified in subsection (3)(b) of this rule, except as specified in subparagraph (1)(b)(ii)(iii).

5. **(C) New Sources Located on Previously Unused Site:**

6. No person owning or controlling a new industrial or commercial noise source located on a previously unused industrial or commercial site shall cause or permit the operation of that noise source if the noise levels generated or indirectly caused by that noise source increase the ambient statistical noise level, 50 or less, by more than 10 dBA in any one hour, or exceed the levels specified in Table 8, as measured at an appropriate measurement point, as specified in subsection (3)(b) of this rule, except as specified in subparagraph (1)(b)(ii)(iii).

7. The ambient statistical noise level of a new industrial or commercial noise source on a previously unused industrial or commercial site shall include all noises generated or indirectly caused by or attributable to that source.
(c) Quiet Areas. No person owning or controlling an industrial or commercial noise source located either within the boundaries of a quiet area or outside its boundaries shall cause or permit the operation of that noise source if the statistical noise levels generated by that source exceed the levels specified in Table 9 as measured within the quiet area and not less than 400 feet (122 meters) from the noise source.

(3) Measurement:
(a) Sound measurements procedures shall conform to those procedures which are adopted by the Department, or to such other procedures as are approved in writing by the Department;
(b) Unless otherwise specified, the appropriate measurement point shall be that point on the noise sensitive property, described below, which is further from the noise source:
   (i) 25 feet (7.6 meters) toward the noise source from that point on the noise sensitive building nearest the noise source;
   (ii) That point on the noise sensitive property line nearest the noise source.

(4) Monitoring and Reporting:
(a) Upon written notification from the Department, persons owning or controlling an industrial or commercial noise source shall monitor and record the statistical noise levels and operating times of equipment, facilities, operations, and activities, and shall submit such data to the Department in the form and on the schedule requested by the Department. Procedures for such measurements shall conform to those procedures which are adopted by the Commission and set forth in Sound Measurement Procedures Manual (NPCS-1);

(5) Exemptions: Except as otherwise provided in subparagraph (1)(b)(B)(ii) of this rule, the rules in section (1) of this rule shall not apply to:

(c) Sounds created by the tires or motor used to propel any road vehicle complying with the noise standards for road vehicles;

(g) Sounds that originate on construction sites.

(k) Sounds created by the operation of road vehicle auxiliary equipment complying with the noise rules for such equipment as specified in OAR 340-035-0010(3)(k).

3 OAR 340-035-0035 provides the DEQ noise rules for industry and commerce and establish noise limits for new industrial or commercial noise sources based upon whether those sources would be developed on a previously used or previously unused site. Pursuant to OAR 340-035-0015(47), a “previously unused industrial or commercial site” is defined as property which has not been used by any industrial or commercial noise source during the 20 years immediately preceding commencement of construction of a new industrial or commercial source on that property. There is no evidence in the record that the proposed facility site has been in industrial or commercial use at any time during the last 20 years, therefore the site is considered a previously unused site and evaluated per the requirements of OAR 340-035-0035(1)(b)(b).

Noise generated by a new industrial or commercial source located on a previously unused site must comply with two standards: the “ambient noise degradation standard” and the “maximum allowable noise standard.” Both of these standards represent allowable noise levels at “real properties normally used for sleeping,” otherwise referred to as a “noise sensitive property.” The analysis area for evaluating compliance with the DEQ noise rules includes the area within and extending 1-mile from the proposed site boundary. Within the analysis area, the applicant identifies 23 noise sensitive properties. Therefore, compliance with the DEQ noise rules, as further described below, is based upon modeled noise levels of proposed facility operation at the identified 23 noise sensitive properties.

Under the ambient noise degradation standard, facility-generated noise must not increase the ambient hourly L10 or L50 noise levels at any noise sensitive property by more than 10 dBA, with ambient noise levels established based on noise measurements taken at an appropriate noise measurement location (point on the noise sensitive property line nearest to the noise source). Under the maximum allowable noise standard at OAR 340-035-0035(1)(b)(b), new industrial or commercial noise sources may not exceed the noise levels specified in the noise sensitive property.

3 A “previously unused industrial or commercial site” is defined in OAR 340-035-0015(47) as property which has not been used by any industrial or commercial noise source during the 20 years immediately preceding commencement of construction of a new industrial or commercial source on that property.

6 OAR 340-035-0015(38) defines noise sensitive property as, “real property normally used for sleeping, or normally used as schools, churches, hospitals or public libraries. Property used in industrial or agricultural activities is not Noise Sensitive Property unless it meets the above criteria in more than an incidental manner.”

7 OAR 340-035-0035(1)(b) establishes appropriate measurement points as also inclusive of “25 feet toward the noise source from that point on the noise sensitive building nearest the noise source,” which was not referenced above because the applicant evaluated ambient based on the point on the property line nearest to the noise source, as also allowed by the rule.
Potential Noise Impacts

The applicant’s evaluation of compliance with DEQ’s noise rules is presented in ASC Exhibit X.

Based upon review of ASC Exhibit X, the Department presents its assessment for Council review of the applicant’s ability to comply with the noise requirements.

Construction

OAR 340-035-0035(3)(b) specifically exempts noise caused by construction activities; however, an evaluation of construction-related noise is presented in accordance with OAR Chapter 345 Division 21 Information requirements and to inform the construction-related noise analysis required under the Council’s Protected Areas and Recreation standards.

Proposed facility construction, including solar components and 230 kV transmission line, would include site preparation, grading, preparation of staging areas and onsite access routes; array foundation installation, conductor installation, and construction of collector substation; solar panel assembly and construction electrical components; inverter pad construction; commissioning of solar array and grid interconnection; installation of transmission structure; panel assembly and construction of collector substation; solar related noise is presented in accordance with OAR Chapter 345 Division 21 Information requirements and to inform the construction-related noise analysis required under the Council’s Protected Areas and Recreation standards.

As presented in ASC Exhibit X, the applicant seeks Council approval of ambient noise measurement procedures other than NPCS-1, for the proposed solar facility and the 230 kV transmission line. To evaluate ambient conditions within the proposed solar facility area, the applicant requests Council approval of a noise measurement procedure based on American National Standards Institute (ANSI) S12.3-2005/Part 2 Quantities and Procedures for Description and Measurement of Environmental Sound – Part 2: Measurement of long-term, wide area sound) and S12.13-2005 (Measurement of Sound Pressure Levels In Air). The applicant represents that the procedures used for ambient measurements are commonly accepted standards within the acoustic engineer industry.

To evaluate ambient conditions along the 11-mile 230 kV transmission line corridor, the applicant requests Council approval of a conservative default ambient noise level, based on the

Bakeoven Solar Project - Draft Proposed Order on Application for Site Certificate
January 17, 2020

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4846-6947-5766v.1 0108111-000002
average L50 nighttime levels measured at the four ambient sound monitoring locations (20 dBA) and adjusted based on a noise level of rainfall assumed to be perceivable by the human ear (6 dBA), equating to a default ambient of 26 dBA. Based on review of information published by health care provider, Center for Hearing and Communication, and BNE.

Environmental noise levels for a transmission line, where corona noise would be generated during wet, rainy conditions, where rainy conditions alone would typically generate noise levels above 50 dBA.

Based on review of the above-referenced procedures and applicant’s supporting information, the Department recommends Council approval for the proposed ambient measurement procedures.

Using the above-referenced procedures, four noise sensitive properties nearest to the proposed solar facility components were identified, at distances of 465, 800, 1,161 and 5,585 feet. At each of the four identified noise sensitive property locations, four short-term (30-minute) sound measurements were taken, with statistical sound levels measured in consecutive 1-second and 1-minute intervals. Measurements of the existing sound levels were conducted for both the daytime (7AM to 10PM) and nighttime (10PM to 7AM) periods. All measurements were taken with a pre-field calibrated Larson Davis 831 real-time sound level analyser, equipped with a PCB model 377B02 ½-inch precision condenser microphone. The applicant confirms that weather conditions during the ambient measurements were conducive for accurate data collection. The results of the ambient noise measurements are presented in Table 11: Summary of Ambient Measurement Results below.

### Table 11: Summary of Ambient Measurement Results

<table>
<thead>
<tr>
<th>NSR ID</th>
<th>Distance to Nearest Facility Fence (feet)</th>
<th>Time Period</th>
<th>Leq</th>
<th>L10</th>
<th>L50</th>
<th>L90</th>
</tr>
</thead>
<tbody>
<tr>
<td>ST-1</td>
<td>1,161</td>
<td>Day</td>
<td>54</td>
<td>44</td>
<td>26</td>
<td>21</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Night</td>
<td>47</td>
<td>35</td>
<td>25</td>
<td>21</td>
</tr>
<tr>
<td>ST-2</td>
<td>800</td>
<td>Day</td>
<td>35</td>
<td>36</td>
<td>29</td>
<td>26</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Night</td>
<td>27</td>
<td>26</td>
<td>22</td>
<td>20</td>
</tr>
<tr>
<td>ST-3</td>
<td>465</td>
<td>Day</td>
<td>54</td>
<td>39</td>
<td>29</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Night</td>
<td>23</td>
<td>28</td>
<td>17</td>
<td>16</td>
</tr>
<tr>
<td>ST-4</td>
<td>5,585</td>
<td>Day</td>
<td>33</td>
<td>37</td>
<td>31</td>
<td>24</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Night</td>
<td>35</td>
<td>31</td>
<td>29</td>
<td>16</td>
</tr>
</tbody>
</table>

Source: JGC Exhibit X Table X-3

As presented in Table 11: Summary of Ambient Measurement Results, ambient conditions as measured at the noise sensitive properties located in closest proximity to proposed facility components range from 26 to 31 dBA for daytime L50 and from 17 to 29 dBA for nighttime L50.

The applicant used two acoustic modeling software programs to evaluate operational noise from the proposed facility - the Corona and Field Effects Program Version 3 (Corona 3) for the 230 kV transmission line and the Computer Aided Noise Abatement (CadnaA) version 2018 MR1 for solar facility components and the transmission line - to model predicted maximum operational noise at noise sensitive properties within the analysis area. Corona 3 uses algorithms to predict a variety of outputs including electric and magnetic field and audible noise from transmission lines. The results of Corona 3 were then input into the CadnaA program to evaluate the maximum operational noise levels of the proposed facility.

CadnaA includes sound propagation factors adopted from International Organization for Standardization’s (ISO) 9613-2 “Attenuation of Sound during Propagation Outdoors” to account for geometric divergence, atmospheric absorption, reflection from surfaces, screening by topography and obstacles, terrain complexity and ground effects, source directivity factors, seasonal foliage effects, and meteorological conditions. Topographical information was imported into the acoustic model using the official U.S. Geological Survey (USGS) digital elevation dataset to accurately represent terrain in three dimensions. Terrain conditions, vegetation type, ground cover, and the density and height of foliage can also influence the absorption that takes place when sound waves travel over land.

Results of the noise analysis are presented graphically on noise contour maps identifying proposed facility component locations and noise sensitive properties within 1-mile of the proposed site boundary, identifying the boundaries of noise contours ranging from 20-25 to 70-75 dBA. Maximum noise levels from the proposed facility, based on rainy conditions during the quietest time (nighttime), are presented in Figure 7: Summary of Acoustic Modeling Results in Rainy Conditions – Nighttime Operations.

<table>
<thead>
<tr>
<th>Source: Oregon Department of Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Draft Proposed Order for Site Certificate</td>
</tr>
<tr>
<td>4846-6947-576v.1 0108111-000002</td>
</tr>
</tbody>
</table>
The proposed facility would be reviewed by an acoustician. Based upon this representation, the specifications and noise warranty data of noise generating equipment and sound power levels validated by manufacturer specifications. Additionally, the noise modeling results show that noise generated during proposed facility operation would not exceed the maximum allowable standard of 50 dBA at any noise sensitive property, even during maximum operational noise/rainy conditions. Additionally, the noise modeling results show that noise generated during proposed facility operation would not exceed the maximum allowable standard of 50 dBA at any noise sensitive property, even during maximum operational noise/rainy conditions. The ambient noise degradation standard requires a demonstration that noise generated during proposed facility operation must not cause the hourly L50 noise level at any noise-sensitive property to exceed 10 dBA above measured ambient conditions or, in this case, ambient conditions ranging from 17 to 31 dBA. Based upon the applicant’s noise analysis and noise contour maps, maximum increases in ambient noise level from proposed facility operation would not exceed 9 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Therefore, the ambient noise degradation standard would not be exceeded at any noise sensitive property, even during maximum operational noise/rainy conditions. The results show that noise generated during proposed facility operation would not exceed the maximum allowable standard of 50 dBA at any noise sensitive property within the analysis area, with maximum statistical noise levels modeled at 35 dBA, as presented in ASC Exhibit X Tables X-8 and X-9. Therefore, the maximum allowable standard would not be exceeded at any noise sensitive property, even during maximum operational noise/rainy conditions. In ASC Exhibit X, the applicant represents that, to ensure compliance with the DEQ noise rules and verify consistency with the noise analysis provided in ASC Exhibit X, the final equipment specifications and noise warranty data of noise generating equipment associated with the proposed facility would be reviewed by an acoustician. Based upon this representation, the Department recommends Council issue the following condition to afford the Department the ability to verify compliance with DEQ’s noise rules, based on consistency of sound power levels associated with final equipment selection compared to equipment information relied upon in ASC Exhibit X:

Recommended Noise Control Condition 1: Prior to construction of the facility or any phase of the facility, the certificate holder shall:

a. Submit to the Department a noise summary report presenting the sound power levels (in dBA) of noise generating equipment including solar array inverters and transformers, substation transformers, and battery system inverters and cooling systems, as applicable to final design. The sound power levels shall be supported by equipment manufacturer specifications and noise data. The certificate holder shall provide, in tabular format, a comparison of the sound power levels used in ASC Exhibit X for noise generating equipment and sound power levels validated by manufacturer specifications.

b. If the sound power levels used in ASC Exhibit X to evaluate compliance with DEQ’s noise rules are lower than sound power levels of final equipment selected, the certificate holder shall provide an updated noise analysis to demonstrate compliance with the ambient degradation standard and maximum allowable threshold. The ambient noise level utilized in ASC Exhibit X may be used for the updated noise analysis, if required.

Conclusions of Law

Based on the foregoing findings, and compliance with the recommended condition, the Department recommends that the Council find that the proposed facility would comply with the Noise Control Regulations in OAR 340-035-0035(1)(b)(B).

IV D 2. Removal-Fill

The Oregon Removal-Fill Law (ORS 196.795 through 196.990) and Department of State Lands (DSL) regulations (ORS 141-085-0500 through 141-085-0785) require a removal-fill permit if 50 cubic yards or more of material is removed, filled, or altered within any “waters of the state.”

The Council, in consultation with DSL, must determine whether a removal-fill permit is needed and if so, whether a removal-fill permit should be issued. The analysis area for wetlands and other waters of the state is the area within the site boundary.

Findings of Fact

The applicant states that a removal-fill permit is not needed for the proposed facility because the facility would not temporarily or permanently impact waters of the state. The applicant conducted wetland delineation studies in 2018. The results of these studies are presented in ASC Exhibit I, and summarized in Table I.1. The applicant completed a wetland delineation report...
and submitted with the report with the ASC Exhibit J, Attachment J-2. As shown in ASC Exhibit J Table J-1, the wetland delineation study determined that there are four types of wetlands and other water features in the analysis area: palustrine emergent wetland; palustrine shrub-palustrine emergent wetland; palustrine shrub-palustrine forested wetland; and intermittent streams. Of these features, palustrine emergent wetlands were found to be the most common. Based on the types of wetlands and other water features, 18 were identified as wetlands and 4 were identified as other water features.

DSL reviewed the wetland delineation report and provided a concurrence letter in August 2019, in which DSL agreed with the wetland delineation and classifications.\(^{22}\) As the applicant demonstrates in ASC Exhibit J and associated wetland delineation report, the proposed facility would not impact waters of the state; therefore, a removal fill permit is not required.

Therefore, the Department recommends the Council find that the proposed facility maintains compliance with the removal-fill law and the certificate holder is not currently required to obtain a removal-fill permit.

Conclusions of Law

Based on the foregoing findings of fact and conclusions, the Department recommends that the Council find that a removal-fill permit is not needed for the proposed facility.

H.0.3. Water Rights

Under ORS Chapters 537 and 540 and OAR Chapter 690, the Oregon Water Resources Department (OWRD) administers water rights for appropriation and use of the water resources of the state. Under OAR 345-022-0000(1)(b), the Council must determine whether the proposed facility would comply with these statutes and administrative rules. OAR 345·021·003(1)(c)(F) requires that if a proposed facility needs a groundwater permit, surface water permit, or water right transfer, that a decision on authorizing such a permit rests with the Council.

Findings of Fact

As explained in ASC Exhibit O, proposed facility construction would use, under high temperatures, dry climatic conditions (i.e. “worst-case conditions”) up to 77 million gallons of water per year for dust suppression, road compaction, concrete foundations, on-site worker drinking and sanitation use. Proposed facility operation would use approximately 1 million gallons of water per year to support O&M building drinking water use and solar panel washing. Estimated water use from proposed facility construction and operation is presented in Table 12 below.

\(^{22}\) BPAFP: pASC Review Agency Comment DSL Concurrence, 2019-09-16.

### Table 12: Estimated Water Use from Proposed Facility Construction and Operation

<table>
<thead>
<tr>
<th>Water Use Description</th>
<th>Quantity/Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction</td>
<td>Gallons/Year</td>
</tr>
<tr>
<td>Site Dust Control</td>
<td>75 million</td>
</tr>
<tr>
<td>Road Compaction</td>
<td>182,400</td>
</tr>
<tr>
<td>Concrete Mixing</td>
<td>1.7 million</td>
</tr>
<tr>
<td>Drinking Water/Sanitation</td>
<td>187,500</td>
</tr>
<tr>
<td>Annual Estimated Construction Water Use =</td>
<td></td>
</tr>
<tr>
<td>Operation</td>
<td>Gallons/Year</td>
</tr>
<tr>
<td>O&amp;M Building</td>
<td>7,500</td>
</tr>
<tr>
<td>Solar Panel Washing</td>
<td>1 million</td>
</tr>
<tr>
<td>Annual Estimated Operational Water Use =</td>
<td>1,007,500</td>
</tr>
</tbody>
</table>

Source: ASC Exhibit O

In ASC Exhibit O, the applicant describes that construction-related water would be obtained from the City of Maupin, through an existing water right permit, or use of an existing or newly constructed well, which would be permitted by a third-party under an Oregon Department of Water Resources-issued limited water use license. Operational water would be obtained by the same sources identified for construction. In ASC Exhibit O, the applicant provides a letter from the City of Maupin dated May 30, 2019, where Mayor Ewing confirms an ability of the city under its existing water right permit number S18591 to provide water to meet the applicant’s forecasted construction related water demand. The applicant asserts that through its communication with the City of Maupin, that the existing water right S18591 could serve the proposed facility’s construction-related water demand during normal and dry conditions throughout the year.

Based on the recommended findings, the Department recommends Council find that the applicant has demonstrated an ability to obtain adequate water for construction and operation of the proposed facility and does not need a groundwater permit, surface water permit, or water right transfer. If such a permit is required by the applicant at a later time, a site certificate amendment would be required to review and consider such a permit application.

Conclusions of Law

Based on the foregoing findings of fact, the Department recommends that the Council conclude that the proposed facility does not need a groundwater permit, surface water permit, or water right transfer.
V. PROPOSED CONCLUSIONS AND ORDER

1. The applicant submitted an application for site certificate to construct and operate approximately 303 MW of solar photovoltaic power generation equipment and its related or supporting facilities (11-mile 230 kV transmission line; collector substation; operations and maintenance building; communication and supervisory control and data acquisition system; temporary staging areas; battery storage) to be located in southern Wasco County. Subject to compliance with the recommended site certificate conditions and based on the preponderance of evidence on the record, the Department recommends Council find that:

1. The proposed Bakeoven Solar Project complies with the requirements of the Oregon Energy Facility Siting Statutes, ORS 469.300 to 469.520.

2. The proposed Bakeoven Solar Project complies with the standards adopted by the Council pursuant to ORS 469.501.

3. The proposed Bakeoven Solar Project complies with all other Oregon statutes and administrative rules identified in the second amended project order as applicable to the issuance of a site certificate for the proposed facility.

Based on the recommended findings of fact, reasoning, recommended conditions and conclusions of law in this draft proposed order, the Department recommends that Council conclude that the applicant has satisfied the requirements for issuance of a site certificate for the proposed Bakeoven Solar Project. The Department further recommends that, pursuant to ORS 469.401, the Chairperson execute the site certificate authorizing the applicant to construct, operate and retire the facility subject to the conditions set forth in the site certificate.

Issued this 17th day of January 2020

The OREGON DEPARTMENT OF ENERGY

By: ____________________________

Todd Cornett
Assistant Director, Energy Facility Siting Division
Oregon Department of Energy
Notice of the Right to Appeal

[Text to be added to Final Order]
Attached please find my comments regarding the above solar project Draft Proposed Order.
Sarah Esterson, Senior Siting Analyst  
Oregon Department of Energy  
550 Capital St. NE  
Salem, Oregon 97301

Re: Comments on Bakeoven Solar Project Draft Proposed Order

While I did not do a thorough review of the application and draft site certificate for the Bakeoven Solar Project, I did review enough material to be able to make some comments regarding this application. I appreciate what I would call “completed staff work” on the part of a developer or an agency. I believe this application and resulting draft proposed order reflect the level of thoroughness that will result in a well placed development that will provide a minimum in resource damage during it’s construction and operation. The bulk of these observations relate to the Fish and Wildlife issues, however, the overall quality of the information the developer provided gives a complete picture of the development impacts and procedures.

Some of the things that I believe will limit the negative and increase the positive outcome of the Bakeoven Solar Development:

a. The applicant did not limit the site boundary to only the siting corridors even though the use of a larger site boundary increases the cost of surveys and other actions required by the site certificate process. Use of a larger site boundary provides more information and options in terms of avoiding areas with significant resource values.

b. The developer used information compiled from a broader area and more sources than many applications to assess wildlife species and use of the area. The inclusion of some actual survey results in the application provide a far more believable review of wildlife impacts that can be expected. This is far more meaningful than limiting the information in the application to only that available through the use of a desk review.

c. The developer included information and surveys regarding bat species present and projected use of the area. Given the declining numbers of bats, due in part to the proliferation of renewable energy projects, it is encouraging to see some data included in the application.

d. The developer complied with the Endangered Species Act by addressing federally protected species as well as state protected species and including the United States Fish and Wildlife Service in the review process.

e. The information in the application was easily understood and not masked by institutional language that serves little value other than avoiding transparency.

f. The applicant freely shared information, responded to questions or concerns and provided access to the development area early in the process.

g. The development itself and it’s components were placed in locations that would not negatively impact Wild and Scenic rivers in the area. The minimal visual impacts that will occur are significant distances away and are unavoidable due to the location of the grid access.
I only saw two areas of the application that gave me pause. One being the request for providing an exception to the bond requirements, however, that was addressed in the draft proposed order.

The other area was the use of habitat categories to establish different levels of mitigation for Category 2 deer winter range. Normally, I would object to this action, however, given the fact that the developer is providing a significant amount of mitigation in the form of avoidance of impacts to wildlife altogether, it seems appropriate in this instance. I am referring to actions including fencing of the development, providing of corridors for animals to escape, moving facility components to avoid directly impacting nesting sites when possible, etc.

Whether you are painting a room or building a solar development, I believe it is the quality of the prep work that dictates the outcome. I look forward to seeing what I expect will be a positive outcome reflecting the work that has gone into preparing for construction of this development.

Irene Gilbert
2310 Adams Ave.
La Grande, Oregon 97850
Phone: 541-963-8160
February 15, 2020

To:
Sarah Esterson,
Senior Siteing Analyst
Oregon Department of Energy
550 Capital Street NE
Salem, OR 97301

From:
Chuck Little
17 Westview Drive
Hermiston, OR 97838

Re: Bakeoven Solar Project

I am writing today to show my support of the Bakeoven Solar Project. The 303 MW photovoltaic solar energy generation project will be a good addition to the renewable energy projects that are already in operation across the state. The balances of those projects are mostly wind energy projects and also some solar projects in some areas around the state.

The Bakeoven Solar Project will be a new project that will also include 100 MW of battery storage capacity. This is an important part of the project as the State of Oregon has set goals to be 100 percent renewable energy productions to move the state away from fossil fuels to produce electrical services.

I am asking the Oregon Department of Energy to grant all of the permits to complete the Backoven Solar Project as soon as possible so the construction can begin.

Thank you,

Chuck Little
Dear Ms. Esterson,

I'm attaching a letter of participation and support for Avangrid's Bakeoven Solar project on behalf of the Deschutes Land Trust. Please let me know if you need anything else at this time.

Best,

Fiona Noonan
Conservation Associate
Deschutes Land Trust
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February 25, 2020

Oregon Department of Energy
c/o Sarah Esterson
550 Capitol St. NE
Salem, OR 97301

Re: Avangrid Renewables Bakeoven Solar Project

Dear Oregon Department of Energy EFSC project reviewers,

We’re writing to confirm that we have been working with Avangrid Renewables and the Oregon Department of Fish and Wildlife to identify mitigation options for Avangrid’s Bakeoven project. Specifically, we’ve discussed the possibility of mitigating impacts through our acquisition and restoration of 4500 acres of high-value upland, riparian, and stream habitats on Trout and Antelope Creeks. We have 25 years of experience in land management and are confident we can ensure durable mitigation as directed by the ODOE and its natural resource advisors.

Habitat degradation remains a significant concern in our region, and we value the opportunity to think strategically with ODOE, ODFW, and solar developers to about developing and implementing high-quality, landscape-scale mitigation projects. We look forward to continuing to work with them as we conserve and improve critical mule deer winter range and other priority habitats.

Sincerely,

Fiona Noonan
Conservation Associate
fiona@deschuteslandtrust.org
Attachment P-2.
Draft Habitat Mitigation Plan

Bakeoven Solar Project
December 2019

Prepared for
Avangrid Renewables, LLC

Prepared by
Tetra Tech, Inc.
ATTACHMENT P-2. DRAFT HABITAT MITIGATION PLAN

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1.0 Introduction

This Habitat Mitigation Plan (HMP) describes how Bakeoven Solar, LLC (Applicant) will mitigate for the unavoidable wildlife habitat impacts of the Bakeoven Solar Project (Facility). Specifically, this HMP outlines how the Applicant will construct and operate the Facility consistent with the Oregon Department of Fish and Wildlife (ODFW) Habitat Mitigation Policy. This plan addresses mitigation for both the permanent impacts of Facility components (permanent impacts) and the temporal impacts associated with the Facility construction (temporary impacts with a longer [5+ years] restoration timeframe). The Applicant proposes three mitigation options, including 1) mitigation banking with ODFW; 2) payment to provide option with Western Rivers Conservancy or Deschutes Land Trust; and 3) acquisition of a conservation easement to protect and enhance a compensatory mitigation area. As presented in the HMP, Option 1 is included to preserve a potential future mitigation option, but the Applicant acknowledges that the appropriate procedures necessary to support a mitigation banking program have not been adopted by ODFW. For Option 2, this Plan specifies the cost of property acquisition, restoration actions, and stewardship costs for long-term protection and management of a mitigation site. Option 3 is an Applicant-developed mitigation site; this plan specifies habitat enhancement actions and monitoring procedures to evaluate the success of those actions, as applicable. The Applicant anticipates that the Facility will be built in phases; therefore, the mitigation options may be used in combination or used in variation per phase (e.g., Option 3 for Phase 1, Option 2 for Phase 2, Option 1 and 2 for Phase 3, etc.).

2.0 Description of the Impacts Addressed by the HMP

The Facility is located entirely within the ODFW Designated Mule Deer Winter Range. ODFW (2013) describes Mule Deer Winter Range in eastern Oregon as limited and essential habitat for big game; therefore, should be considered as Category 2 under ODFW’s Habitat Mitigation Policy. It is not possible to site the Facility outside of the designated winter range because the Facility is location-dependent on its interconnection point at Bonneville Power Administration’s Maupin Substation, which is also in Mule Deer Winter Range. Therefore, impacts to Category 2 are unavoidable due to the Facility’s interconnection location and the overlapping Mule Deer Winter Range.

Notwithstanding the overarching habitat categorization, the area within the micrositing corridor is primarily composed of eastside grassland (habitat types Upland Grassland, Shrub-Steppe and Shrubland; subtype Eastside Grassland) and planted grasslands, with smaller areas of shrub-steppe habitat (habitat types Upland Grassland, Shrub-Steppe and Shrubland; subtype Shrub-Steppe) that may be used by various species (Exhibit P, Tables P-2 and P-3). Essential habitat values for quality big game winter range, such as thermal cover, security from predation and harassment, quality forage, and limited disturbance are generally lacking from the micrositing corridor because it is

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This HMP will be incorporated by reference in the site certificate for the Bakeoven Solar Project and must be understood in that context. It is not a “stand-alone” document.
mostly composed of planted grassland and highly disturbed native grassland (Exhibit P, Section 8.1.1).

As presented in Exhibit P, no areas of native eastside grassland or shrub-steppe habitat were field-characterized in 2018 as Category 2 habitat. Planted grasslands ranging from Categories 3-5 account for 948.4 acres (22.8 percent) of the micrositing corridor. Areas of eastside grassland and shrub-steppe habitat dominated by non-native plant species (Categories 4 and 5) comprise 1762.1 acres (42.3 percent) of the micrositing corridor (see Exhibit P, Tables P-3 and P-4). The remaining areas of eastside grassland and shrub-steppe have a higher native species composition (Category 3), and comprise 997.2 (23.9 percent) acres of the micrositing corridor.

Permanent impact areas are those that would be converted from the existing condition to a different condition for the life of the Facility. Solar array areas will be fenced, and all areas inside the fence are considered permanently disturbed. In addition to the solar array, fencing will occur at the collector substation, the operations and maintenance (O&M) building, and the battery storage area, as required by electrical code or security needs (see Application for Site Certificate [ASC] Exhibits B and C). Temporary impacts will be fully mitigated through successful implementation of the Revegetation Plan (Attachment P-3 to Exhibit P). However, some areas of shrub-steppe that will be temporarily impacted include sagebrush stands that could take longer than 5 years to be restored. Even where restoration of this habitat subtype is successful, there is a loss of habitat function during the restoration period. Therefore, this HMP includes mitigation for both permanently impacted habitat (2,473.0 acres) and select areas of temporarily impacted shrub-steppe habitat (shrub-steppe subtype: 32.0 acres) that results in a temporal loss of habitat quality (Table 1).

The Facility will not have any impacts on Category 1 habitat. In accordance with ODFW’s Habitat Mitigation Policy, impacts to Category 6 habitat do not require mitigation. All remaining Category 3, 4, and 5 habitat has been re-categorized as Category 2 habitat because the Facility is within ODFW’s Designated Mule Deer Winter Range, which overlaps the areas of temporary and permanent impact (ODFW 2013). Based on this definition, Table 1 presents anticipated acres of impact for Category 2 habitat present at the Facility, in addition to the preliminary habitat categorization of these areas before the application of this overlay.

### Table 1. Acres of Impact to Habitat Categories and Types within the Proposed Micrositing Corridor

<table>
<thead>
<tr>
<th>Final Habitat Category</th>
<th>Preliminary Habitat Category</th>
<th>Habitat Type-Subtype</th>
<th>Permanent Impact</th>
<th>Temporary Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>3</td>
<td>Riparian Forest and Natural Shrubland Complexes – Eastside Riparian</td>
<td>0.6</td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Eastside Grassland</td>
<td>579.1</td>
<td>14.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe</td>
<td>103.4</td>
<td>32.0</td>
</tr>
<tr>
<td>Final Habitat Category¹</td>
<td>Preliminary Habitat Category</td>
<td>Habitat Type-Subtype²</td>
<td>Permanent Impact</td>
<td>Temporary Impact</td>
</tr>
<tr>
<td>-------------------------</td>
<td>-----------------------------</td>
<td>-----------------------</td>
<td>------------------</td>
<td>------------------</td>
</tr>
<tr>
<td>4</td>
<td>Agriculture, Pasture, Mixed Environ – Planted Grassland</td>
<td>423.4</td>
<td>16.2</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cliff, Caves, and Talus</td>
<td>0.0</td>
<td>0.4</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Open Water - Lakes Rivers Streams – Seasonal Pond</td>
<td>0.7</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Open Water - Lakes Rivers Streams – Intermittent or Ephemeral Streams</td>
<td>0.0</td>
<td>&lt;0.1</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Eastside Grassland</td>
<td>792.3</td>
<td>17.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe</td>
<td>1.8</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Agriculture, Pasture, Mixed Environ – Planted Grassland</td>
<td>177.1</td>
<td>7.3</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Eastside Grassland</td>
<td>303.4</td>
<td>17.4</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe</td>
<td>91.1</td>
<td>47.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upland Forests and Woodlands – Juniper woodland</td>
<td>0.0</td>
<td>2.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Agriculture, Pasture, Mixed Environ – Planted Grassland</td>
<td>0.1</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Category 2 Final Total</td>
<td></td>
<td></td>
<td>2,473.0</td>
<td>157.6</td>
</tr>
<tr>
<td>6</td>
<td>Agriculture, Pasture, Mixed Environ – Orchards, Vineyards, Wheat Crops and Other Row Crops</td>
<td>240.4</td>
<td>4.3</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Urban and Mixed Environ</td>
<td>3.6</td>
<td>14.7</td>
<td></td>
</tr>
<tr>
<td>Category 6 Final Total</td>
<td></td>
<td></td>
<td>244.0</td>
<td>19.0</td>
</tr>
<tr>
<td>Grand Total</td>
<td></td>
<td></td>
<td>2,717.0</td>
<td>176.6</td>
</tr>
</tbody>
</table>

Note: Totals in this table may not be precise due to rounding.
1. Final Category following application of ODFW Designated Mule Deer Winter Range overlay.
2. Only impacted Habitat Types-Subtypes present within the proposed micrositing corridor are represented.
3. Temporarily impacted shrub-steppe habitat.

The Applicant proposes to begin construction as soon as June 2020, and to construct the Facility in phases. The size and construction schedule for each phase will be based on market demand, but the entire Facility, including all phases, will be completed by 2026 unless the Applicant seeks an amendment to extend the construction deadline. Table 2 provides an example phased construction schedule. The impact analysis presented in the ASC and mitigation outlined in this HMP represents the fully built-out scenario of 303 megawatts. Mitigation will be determined prior to the...
construction of each phase. If phases are transferred to a new Certificate Holder, then any mitigation obligations will also be transferred. For example, if a mitigation site is established for Phase 1 (i.e., Option 3) then the real estate rights (e.g., conservation easement), monitoring requirements, and liability of obtaining success criteria would be transferred to the new Certificate Holder. If the original Certificate Holder satisfies the mitigation obligation using payment-to-provide mitigation (i.e., Options 1 or 2) then the mitigation obligation for any future owner would be complete. A Site Certificate transfer would require approval by EFSC, so there is ability to verify mitigation status during a transfer of ownership.

### Table 2. Example Construction Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>Final engineering and begin construction.</td>
</tr>
<tr>
<td>2021</td>
<td>Phase 1 construction and operation.</td>
</tr>
<tr>
<td>2022</td>
<td>Phase 2 construction and operation.</td>
</tr>
<tr>
<td>2023/2024</td>
<td>Phase 3 construction and operation.</td>
</tr>
<tr>
<td>2026</td>
<td>Construction completion deadline for all phases.</td>
</tr>
</tbody>
</table>

#### 3.0 Methods for Calculating the Size of the Mitigation Area

The mitigation area will be determined for each phase of the Facility based on the final design for that phase and actual habitat impacts (i.e., Category 2 vs. Category 6 habitat). Before beginning construction of each phase of the Facility, the Applicant will provide the Oregon Department of Energy (ODOE) with a map showing the final design configuration for that phase of the Facility, and a table showing the estimated acres of permanent and temporary impacts by habitat category (Table 1). Mitigation calculations for each phase will be based on current habitat conditions that will be mapped and field verified by the Applicant no earlier than 2 years prior to construction of each phase.

Current habitat conditions will be used to calculate the size of the mitigation area using the mitigation ratios presented in Table 3. Use of these mitigation ratios will ensure that the mitigation area is large enough to achieve “no net loss” of habitat quantity or quality and that a “net benefit” in habitat quantity or quality is provided. In addition, all mitigation options described below include a habitat enhancement component through either payment to third-party or restoration actions performed by the Applicant. Therefore, implementation of this HMP will result in habitat mitigation that is consistent with the ODFW Habitat Mitigation Policy.
For temporal impacts that require mitigation, the mitigation area will include up to 0.5 acres for every 1 acre of Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe sub-habitat type that is temporarily affected by construction activities (but outside the Facility footprint). The size of this portion of the mitigation area assumes that restoration of disturbed eastside grassland and shrub-steppe habitat is successful, as determined under the Revegetation Plan. Other habitat types will be restored following the methods described in the Revegetation Plan.

Because the Facility will be constructed in phases, it is assumed that compensatory mitigation will be based on the new impacts of each phase, and there would be no double counting of impacts associated with shared facilities with prior phases (e.g., shared transmission line or substation).

### 4.0 Mitigation Options

The Applicant has identified three options for addressing the mitigation obligation where habitat protection and enhancement and/or commensurate funding are feasible and consistent with this HMP. Each option is located within the Columbia Plateau and “in proximity” to the Facility. The Applicant may use one option or a combination of options to mitigate for habitat impacts, and will determine the combination of the mitigation options that best correlate to the impacted areas in consultation with ODFW and the affected landowners, subject to ODOE’s approval. As described above, Option 1 is not an available mitigation option at the time of ASC review and approval; but the Applicant preserved the right to use Option 1 should it be available in the future.

The final mitigation approach will offer enough suitable habitat to achieve the ODFW goal of no net loss of habitat quantity or quality, and provide a net benefit in habitat quantity. As the potential mitigation locations are within ODFW-mapped Mule Deer Winter Range, acquisition of these areas constitutes Category 2 habitat regardless of the habitat condition, and thus meets the ODFW goal of providing a net benefit in quantity, as required by ODFW.

### Table 3. Compensatory Mitigation Ratios

<table>
<thead>
<tr>
<th>Final Habitat Category</th>
<th>Current Habitat Category</th>
<th>Mitigation Ratio Permanent</th>
<th>Mitigation Ratio Temporary</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>2</td>
<td>1.5:1</td>
<td>0.5:1 for Shrub Steppe habitat</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>1.3:1</td>
<td>0.5:1 for Shrub Steppe habitat</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>1.2:1</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>1.1:1</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>6</td>
<td>None</td>
</tr>
</tbody>
</table>

1. Final Category following application of ODFW Designated Mule Deer Winter Range overlay.
2. Current habitat condition and category as mapped by the Applicant prior to construction.
3. Permanent impact areas based on final design and includes the Facility’s footprint. No mitigation offered for Category 6 habitat.
4. Compensatory mitigation for temporal habitat loss to current Category 2 or 3 Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe sub-habitat type (see Table 1). Other habitat types will be restored following the methods described in the Revegetation Plan.

Commented [A1]: ODFW JT Comment: This table is reasonable for Bakeoven, given the current condition of habitats onsite and the characteristic of the landscape within the project area.

Commented [A2R1]: SARAH COMMENT: The key requirements for Category 2 are that they achieve no net loss in quantity and quality, and a net benefit in quantity or quality. Technically speaking, the 1:1:1 is still net benefit in quantity, so they are meeting the letter of the policy. However, that does not mean much room for failure if the mitigation site were to underperform. What this means is that we need to ensure thorough coverage of monitoring sites across the mitigation project area, and we need calculated and quantitative success criteria so we can closely monitor performance. With a higher ratio, we have greater assurance of success.

Commented [A3]: From Sarah Esterson: Please include a discussion of duration in Section 4 (term versus perpetuity).

Commented [A4]: AVANGRID COMMENT – deleted as mitigation ratios are now described in the HMP. Previously, the Applicant sought to finalize mitigation ratios prior to construction when the mitigation option was selected.

Commented [A5]: ODFW JT Comment: As discussed, with the applicant, mitigation parcels within the BGWR meet the Category 2 designation, but they should also be chosen to replicate the habitats as classified within the impacted footprint. For example, a mitigation parcel that is Category 5 based on condition would not wholly mitigate for Cat 3 habitat; that would in essence constitute a net loss.

Commented [A6R5]: SARAH COMMENT: I suppose Cat 5 could be used as mitigation, but only if they intended to perform some pretty serious uplift to raise the function to Cat 3. To do this, their ratio would need to take the failure risk into account as well as the temporal loss (time it would take for the Cat 5 to improve to Cat 3). Also important to note that shrub-steppe cannot be mitigated with grassland, so habitat TYPE is also important in meeting the in-kind standard.
no net loss of habitat quantity; any enhancement actions successfully performed would result in a net benefit in habitat quality. Prior to operation of the Facility, or a particular phase of the Facility, the Applicant will acquire the legal right to create, maintain, and protect the habitat mitigation area for the life of the Facility\(^2\) by means of an outright purchase, conservation easement, or similar conveyance, and will provide a copy of the documentation to ODOE. The duration of mitigation Option 1 and Option 2 would be in perpetuity (i.e., permanent conservation of habitat), whereas the duration of Option 3 would be limited to the life of the Facility (i.e., a limited term).

### 4.1 Option 1: ODFW Payment-to-Provide

The Applicant understands that ODFW is considering a payment-to-provide program that could be used to mitigate habitat impacts related to energy facilities. However, at this time, this program is not yet available. Should such a program become available in the future, the Applicant could use a payment-to-provide mitigation option with the approval of ODOE and ODFW.

### 4.2 Option 2: Third-Party Payment-to-Provide

Under this option, the Applicant would partner with either Western Rivers Conservancy (Option 2a) or the Deschutes Land Trust (Option 2b) in land acquisition for the purpose of habitat protection and restoration. This mitigation option has the ability to achieve landscape-level habitat protection because the Applicant would partner with a land trust on a larger mitigation project. The Applicant believes this mitigation option offers substantial benefits mule deer because it enables more winter range to be protected than a traditional, stand-alone mitigation site (Option 3).

The Applicant would meet its mitigation obligation by providing a one-time payment to the third-party mitigation provider prior to commercial operation of the Facility, or phase of the Facility. The payment would take into consideration the cost of property acquisition for the mitigation area (i.e., Land Costs), habitat improvement actions (i.e., Restoration Action Costs or Habitat Enhancement Actions), maintenance and monitoring for long-term protection and management of the site (i.e., Stewardship Costs). The following formula would be used to determine the total mitigation payment:

\[
\text{Mitigation cost per acre} = M \times (R + L + V + S)
\]

Where:

- \( M \) = Mitigation ratio as defined in Section 3
- \( R \) = Restoration costs per acre + contract administration costs to implement restoration
- \( L \) = Restoration maintenance costs per acre
- \( V \) = Land value per acre. Land costs of the mitigation site based on the appraised land value, actual costs, or a value determined by the third-party mitigation provider

\(^2\) As used in this Plan, “life of the facility” means continuously until the Facility site is restored and the site certificate is terminated in accordance with Oregon Administrative Rules 345-027-0110.
• \( S = \text{Stewardship endowment costs per acre, determined by the third-party mitigation provider} \)

The two mitigation opportunities are considered “in-kind” mitigation, as both mitigation sites are within the ODFW-mapped Mule Deer Winter Range, and each site has grassland and shrub-steppe habitat types that are similar to the Facility’s micrositing corridor. Because the equation above assumes a proportional payment to the acquisition and maintenance of the third-party’s mitigation site, no specific habitat assessment of the mitigation site will be provided.

Prior to the construction, the Applicant would provide ODOE with a Memorandum of Understanding (MOU) between the Applicant and the third party mitigation provider that that documents the transaction, confirms the applicability of the above mitigation equation, and includes a copy of the mitigation site’s management plan. The management plan will be prepared by the third-party and would describes the long-term management goals and monitoring program for the mitigation site. The Applicant will request that the management plan acknowledge that the monitoring reports be available for ODOE review.

The Applicant has identified two partners, Western River Conservancy and Deschutes Land Trust, that both have near-term plans for large scale habitat conservation projects in Wasco County. This HMP assumes that either option (e.g., Option 2a, or Option 2b) could be executed prior the operation of any Facility phase; if the third-party has not closed on the purchase of the mitigation site prior to construction, then this option is not feasible.

4.2.1 Option 2a. Western Rivers Conservancy

Under Option 2a, the Applicant would contribute funds to Western Rivers Conservancy that would be used to support the purchase of lands along the John Day River in Wasco County. The subject parcel is a former ranch located along the lower John Day River that includes about 30,000 acres and is at risk of being subdivided into smaller parcels because the landowner plans to sell the property. The Applicant’s contributions would support Western River Conservancy’s purchase for the entire property and maintain this large continuous area as a single tract. Western River Conservancy is currently negotiating the purchase terms with the landowner and the exact location of the mitigation site is not publicly available at this time.

The land would be eventually transferred to the Bureau of Land Management (BLM) and added to the John Day River Wild and Scenic Designation. BLM would manage the land under its John Day Basin Resources Management Plan, which includes management objectives to maintain or improve winter range for deer and elk (Objective W1) and special considerations for areas within Wild and Scenic River designations. Western Rivers Conservancy would transfer land to the BLM depending on the availability of Land and Water Conservation Funds allocated by the U.S. Congress. Western Rivers Conservancy will manage and maintain the lands until this transfer occurs. During this interim period, Western River Conservancy would implement an interim management plan that

\[ \text{https://www.blm.gov/or/districts/prineville/plans/pdo_rodrmp_John_Day_Basin_RDM-06122015.pdf} \]
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precludes cattle grazing, limits public access to foot access only, and potentially includes removing structures.

BLM’s John Day Basin Resource Management Plan allows for mineral and energy extraction in the planning area but these activities are not allowed within land within Wild and Scenic River designation. The land acquisition deal is structured to preclude future mineral development. There are no executed mineral leases on the property, but Western Rivers Conservancy is aware of three outstanding mineral reservations. At part of its due diligence, Water River Conservancy will complete a third-party evaluation of mineral resources potential to assess the actual resources and feasibility for future mineral development. If this evaluation indicates a possibility of mineral development, then Western Rivers Conservancy will offer to purchase the mineral reservations or rights, and work with the BLM to expressly preclude mineral development in documents (e.g., National Environmental Policy Act documents) prepared for the land transfer. Based on this approach, the Applicant believes there is little chance of future mineral development that could affect the mitigation lands associated with the Facility. Additionally, by law, all property acquired by federal agencies utilizing a Land and Water Conservation Fund appropriation must be managed for conservation and may not be sold.

The Western Rivers Conservancy mitigation option would benefit wintering deer, as robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of winter deer habitat (ODFW 2011). During severe winters, snow can cover annual grasses and native bunch grasses, so access to nutritious woody vegetation (i.e., shrubs) is essential to overwinter survival (ODFW 2011).

Western River Conservancy will monitor the mitigation site per the terms of its interim management plan, which will be provided to ODOE by the Applicant. Once transferred to BLM, then monitoring needs and objectives would follow BLM’s resources management plan. But over time, Western Rivers Conservancy would revisit the mitigation site to verify that the goals of the original project have been met. This assessment could include researching the background of the project, conducting field inspections, interviewing current land managers and other people with an interest in the property.

4.2.2 Option 2b. Deschutes Land Trust

Under Option 2b, the Applicant would contribute funds to the Deschutes Land Trust for the acquisition and management of a 5,820-acre property in south Wasco County, known as the Trout Creek Preserve. The Deschutes Land Trust would own and maintain this site, with an overlapping conservation easement held by the Oregon Watershed Enhancement Board (OWEB). The Trout Creek Preserve is within the ODFW-defined winter range for mule deer and elk. Similar to the Western Rivers Conservancy mitigation option, the Deschutes Land Trust mitigation option would

1 See http://www.westernrivers.org/projectatlas/stewardship/
benefit wintering deer as robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of winter deer habitat (ODFW 2011).

The Deschutes Land Trust would develop a management plan for the Trout Creek Preserve with input from ODFW, and conservation objectives will focus on stream protection and rangeland improvements. Monitoring would consist of assessing habitat conditions, taking photos or acquiring aerial imagery to compare with previous/baseline photos, looking at the success of various treatments, and checking for misuse or damage to the property. Deschutes Land Trust has a stewardship program respond to issues on the mitigation site on a regular basis, such as minor weed encroachments, fence repairs, or dealing with human trespass issues. Deschutes Land Trust would conduct annual monitoring for the entire Trout Creek Preserve, and would update its management plan every 5 years based on monitoring results and opportunities for adaptive management. The MOU between the Applicant and Deschutes Land Trust will specific that the updated management plans be provided to ODOE when available (i.e., every 5 years).

4.3 Option 3: Conservation Easement Lands Adjacent to the Facility

Under this option, the Applicant would establish conservation easements adjacent to the Facility. In consultation with participating landowners, the Applicant has identified two areas that could be used for mitigation sites. First, the A&K Ranch site includes multiple parcels totaling 2,428 acres (Figure 1). Second, the Maupin Opportunity Area is a larger area about 40,322 acres southwest of the Facility (Figure 1). Both areas are within the ODFW-defined Mule Deer Winter Range and have enhancement opportunities beneficial to big game and grassland birds.

Some of the parcels of the A&R Ranch site are along Bakeoven Creek and contiguous with land managed by the BLM, providing an opportunity for integrated enhancement over a larger area. As described above under Option 2, robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of deer winter habitat. The Oregon Mule Deer Initiative (ODFW 2011) identified these types of habitats as highly impacted compared to historical conditions, noting that riparian areas have been degraded and often lack quantity and diversity of shrub species. Therefore, enhancement of riparian habitat along Buck Hollow Creek would benefit wintering mule deer.

The second mitigation area is known as the Maupin Opportunity Area and was recommended by ODFW for consideration by the Applicant in an August 2019 meeting (Figure 1). The property is proximate to the site boundary, provides ample potential acreage, and is composed of similar habitat types suitable for in-kind mitigation. A portion of the property is located immediately south of Bakeoven Road, near the westernmost section of the proposed transmission line. Habitat in this area was desktop delineated (as shown in Exhibit P Figure P-4) as primarily shrub-steppe and planted grassland habitat, with intermittent riparian, wetland, and developed areas. Much of the area shown in the figure was within the boundary of the 2018 Boxcar Fire. Areas to the north of Bakeoven Road were not impacted by this disturbance. Per ODFW (pers. comm., Jeremy Thompson, August 19, 2019), before the fire, the habitat with the Maupin Opportunity Area was similar to habitat within the site boundary; however, its condition following fire disturbance and a year of
recovery time is unknown. Per ODFW, this area likely offers opportunities for upland and grassland habitat restoration, to mitigate for permanent and temporary impacts to grassland habitats due to the construction and operation of the Facility (Table 1). Enhancement of grassland habitat in this area would potentially improve forage quality for wintering mule deer and offer improved conditions for grassland bird species as well.

Per ODFW request (pers. comm., Jeremy Thompson, August 19, 2019), the Applicant has performed a desktop analysis of the remainder of the approximately 40,322-acre area. Using pre-fire imagery via Google Earth, the Applicant confirmed that the property appears to be primarily a mix of upland grasslands (some appear to be planted), and a mosaic of shrublands and grasslands. Pre-fire, junipers were encroaching on these shrub-steppe habitats from lower-elevation draws and possible riparian areas, but the condition of these trees post-fire is unknown. If Option 3 is pursued, the Applicant will continue to work with ODFW to identify opportunities to protect and enhance habitats in this area, and to define the appropriate monitoring of mitigation parcels. Prior to construction, the Applicant will provide an updated desktop analysis to confirm the habitat subtype within the mitigation parcel(s).

### 4.3.1 Habitat Enhancement Actions

If Option 3 is selected, the Applicant will develop a management plan for the selected mitigation site that includes habitat enhancement actions to improve the habitat conditions of the mitigation site. The objectives of habitat enhancement are to protect habitat within the mitigation area from degradation and to improve the habitat quality of the mitigation area. By achieving these objectives, the Applicant can address the permanent and temporal habitat impacts of the Facility and meet the ODFW goals of no net loss of habitat quantity or quality and a net benefit in habitat quantity or quality for impacts to Category 2 habitat. The Applicant may choose one or more of the following enhancement actions based on the needs of the selected habitat mitigation area to improved habitat conditions, as appropriate and feasible:

1. **Shrub Planting**. The Applicant would plant sagebrush or other native shrubs in locations within the habitat mitigation area where existing native shrubs are stressed, or where recent wildfires have occurred. The Applicant would determine the size (including number of shrubs and age of shrubs – seedlings or transplanted mature plants) of the shrub-planting areas and the shrub species based on the professional judgment of a qualified biologist after a ground survey of actual conditions. The size of the shrub-planting areas will depend on the size of the available mitigation area and opportunity for survival of planted shrubs. If appropriate, other native shrubs may include antelope bitterbrush (*Purshia tridentata*), golden currant (*Ribes aureum*), and winterfat (*Krascheninnikovia lanata*). The shrub survival rate at 4 years after planting is an indicator of successful enhancement of habitat quality to Category 2. The Applicant would complete the initial shrub planting within 1 year after the beginning of construction of the Facility, or a particular phase of the Facility. Supplementing existing, but disturbed, sagebrush areas with sagebrush seedlings or transplanted mature plants would assist the restoration of this valuable shrub-steppe
component. The Applicant would obtain shrubs from a qualified nursery, and would identify the area to be planted with sagebrush or other native shrubs after consultation with ODFW, subject to final approval by ODOE. The Applicant would mark the planted shrub clusters at the time of planting for later monitoring purposes, and would keep a record of the number of shrubs planted. Plantings would generally be considered successful if a 20 percent survival rate is achieved after 4 years.

2. **Weed Control.** The Applicant would implement a weed control program. Under the weed control program, the Applicant would conduct a pre-management weed assessment to identify the type and percentage of non-native species within the mitigation area. The Applicant would then monitor the mitigation area to locate weed infestations. The Applicant would continue weed control monitoring, as needed, for the life of the Facility. As needed, the Applicant would use appropriate methods to control weeds. Appropriate weed control methods shall include identification of noxious weeds within the mitigation area, timing, herbicides, and application mechanism and be based on consultation with the county weed control authority. Weed control on the mitigation site will reduce the spread of noxious weeds within the habitat mitigation area and on any nearby grassland, Conservation Reserve Program or cultivated agricultural land. Weed control will promote the growth of desirable native vegetation and planted sagebrush. The Applicant may consider weeds to be successfully controlled when weed clusters have been eradicated or reduced to a non-competing level. Weeds may be controlled with herbicides or hand-pulling. The Applicant would notify the landowner of the specific chemicals to be used on the site and when spraying will occur. To protect locations where young desirable forbs may be growing, spot-spraying may be used instead of total area spraying.

3. **Seeding.** The Applicant would plant an ODFW-approved seed mix within the habitat mitigation area in areas that have been recently disturbed (e.g., recent wildlife or weed treatment). The method for seed application would be determined primarily based on the size of the area to be seeded. The size of the seeded area will depend on the amount of recently disturbed area within the mitigation area. The Applicant would complete the initial seeding within 1 year after the beginning of construction of the Facility, or a particular phase of the Facility. The Applicant would record and mark the seeded areas at the time of seeding for later monitoring purposes.

4. **Fire Control.** The Applicant would implement a fire control plan for wildfire minimization when Facility staff are working within the mitigation area. The Applicant would provide a copy of the fire control plan to ODOE before starting habitat enhancement actions. The Applicant would include in the plan appropriate fire prevention measures, methods to detect fires that may occur and a protocol for fire response if a fire were to occur when Project staff were present. If any part of the mitigation area is damaged by future wildfire, the Applicant would assess the extent of the damage and implement appropriate actions to restore habitat quality in the damaged area.
5. **Riparian Planting.** The Applicant would plant appropriate riparian species along streams to enhance these riparian areas, if present, for the benefit of fish and big game. Riparian plantings will improve access to nutritious woody vegetation for wintering deer, which is essential to over-winter survival during severe winters when annual grasses and native bunchgrasses are covered in snow. Riparian plantings will improve shading of streams, which will improve temperature conditions for fish at the location of plantings, as well as downstream. Riparian plantings will also provide cover for big game and help stabilize soil.

6. **Fence Building.** The Applicant would build fencing around the riparian plantings to reduce grazing pressure and allow riparian vegetation to grow. Fencing would be designed to exclude cattle but not deer. Woody vegetation is used by deer for foraging in the winter and provides cover for insulation and hiding.

7. **Juniper Removal.** Where appropriate, the Applicant would remove encroaching juniper to increase the amount of sunlight, moisture, and nutrients available for shrubs and forbs used by mule deer.

8. **Habitat Protection.** The Applicant would restrict uses of the mitigation area that are inconsistent with the goals of no net loss of habitat quantity or quality and a net benefit in Category 2 habitat quantity or quality.

Table 4 outlines the anticipated costs and benefits of various enhancement actions, as well as the anticipated cost of operations and maintenance.

**Table 4. Estimated Restoration Cost Per Unit and Benefit to Mule Deer Winter Range**

<table>
<thead>
<tr>
<th>Type</th>
<th>Action</th>
<th>Cost per Unit</th>
<th>Units</th>
<th>Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhancement</td>
<td>Shrub Planting</td>
<td>$136.95</td>
<td>Per acre</td>
<td>Provide access to nutritious woody vegetation during winter, especially severe winters when snow covers grass forage, in order to improve over-winter survival. Deer on winter ranges without a shrub component often have high rates of over-winter mortality (ODFW 2011).</td>
</tr>
<tr>
<td></td>
<td>Biological, Chemical, or Mechanical Weed treatment</td>
<td>$8.81 – $257.73</td>
<td>Per acre</td>
<td>Reduce competition with desirable forage species to improve or maintain mule deer forage quality and quantity. Impacts of invasive species on Oregon’s fish and wildlife resources are one of the seven most pressing conservation issues identified in the Oregon Conservation Strategy (ODFW 2016).</td>
</tr>
</tbody>
</table>
## Attachment P-2. Draft Habitat Mitigation Plan

<table>
<thead>
<tr>
<th>Type</th>
<th>Action</th>
<th>Cost per Unit</th>
<th>Units</th>
<th>Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Riparian Planting</td>
<td>$1,220.60 1</td>
<td>Per acre</td>
<td>Provide access to nutritious woody vegetation during winter, especially severe winters when snow covers grass forage, in order to improve over-winter survival. Robust riparian vegetation with a high diversity of woody shrub species along streams are an important component of deer winter habitat (ODFW 2011).</td>
</tr>
<tr>
<td></td>
<td>Juniper Removal</td>
<td>$300-$450 2</td>
<td>Per acre</td>
<td>Increase the amount of sunlight, moisture, and nutrients available for shrubs and forbs used by mule deer (ODFW 2014). Shrubs are important where snow is deep during winter (ODFW 2016).</td>
</tr>
<tr>
<td></td>
<td>Rangeland Broadcast/Drill Seeding</td>
<td>$198.53 - 293.48 1</td>
<td>Per acre</td>
<td>Establish desirable forage species in areas that have been disturbed (e.g., following high intensity fire, juniper treatments, or repeated weed treatments) and provide competition for weeds 4. Perennial grasslands and sagebrush steppe are important habitat features of key deer winter range areas (ODFW 2016).</td>
</tr>
<tr>
<td></td>
<td>Hydroseeding (of Critical Areas)</td>
<td>$1,092.93 1</td>
<td>Per acre</td>
<td>Reduce grazing pressure on important shrubs by improving cattle distribution, and enhance riparian areas which could then be used by mule deer as fawning habitat 4. Woody vegetation (e.g., bitterbrush, aspen, alder, willow, oak) are used by deer for foraging in the winter, and provide cover for insulation and for hiding (ODFW 2016).</td>
</tr>
<tr>
<td></td>
<td>Wildlife Exclusion Fence Building</td>
<td>$5.03 1</td>
<td>Per foot</td>
<td>Reduce grazing pressure on important shrubs by improving cattle distribution, and enhance riparian areas which could then be used by mule deer as fawning habitat 4. Woody vegetation (e.g., bitterbrush, aspen, alder, willow, oak) are used by deer for foraging in the winter, and provide cover for insulation and for hiding (ODFW 2016).</td>
</tr>
</tbody>
</table>

| Operations                | Annual Operation and Maintenance| $33 3       | Per acre | N/A                                                                                                                                                                                                 |

1. Based on the Fiscal Year 2019 Oregon Natural Resources Conservation Service Environmental Quality Incentives Program Practice Payment Rate Schedule (NRCS 2019).
3. This O&M cost is an estimate of the cost per acre per year (not including acquisition/easement costs) based on the research presented in the Independent Economic Analysis Board’s 2007 Investigation of Wildlife O&M Costs. The average cost per acre presented in that document was $24 in 2004 dollars, this has been adjusted to reflect 2019 dollars (IEAB 2007).

### 4.3.2 Monitoring

For Option 3 (Conservation Easement), the Applicant will hire a qualified investigator (botanist, wildlife biologist, or revegetation specialist) to conduct a comprehensive monitoring program for the mitigation area, as appropriate. The purpose of this monitoring is to evaluate on an ongoing basis:

Commented [A12]: ODFW JT Comment: Access and slope are much different in Wasco County. This range replicates actual costs realized in Juniper treatments locally through SWCD.

Commented [A13]: ODFW JT Comment: As Sarah stated above, monitoring will need to occur with option 2, there must be some assurance that success was achieved on-site.
basis the protection of the habitat quality and the results of enhancement actions, especially during the winter and wildlife breeding seasons.

The investigator will monitor the habitat mitigation area for the life of the Facility beginning in the year following the initial planting. Monitoring will occur annually during the first 10 years following initial planting, then will occur every 3 years thereafter. The Applicant will identify appropriate monitoring actions for the Conservation Easement and the habitat enhancement actions that are implemented in consultation with ODOE and ODFW. Depending upon specific habitat enhancement actions implemented, the investigator may carry out the following monitoring procedures:

1. Assess vegetation cover (species, structural stage, etc.) and progress toward meeting the success criteria;
2. Record environmental factors (such as precipitation at the time of surveys and precipitation levels for the year);
3. Record any wildfire that occurs within the mitigation area and any remedial actions taken to restore habitat quality in the damaged area;
4. Assess the success of the weed control program and recommend remedial action, if needed; and
5. Assess the survival rate and growth of planted species.

The investigator will visit identified monitoring points within planted areas. Plantings will generally be considered successful if a 20 percent survival rate is achieved after 4 years. The investigator will report on the timing and extent of any livestock grazing that has occurred within the mitigation area since the previous monitoring visit.

5.0 Success Criteria

Mitigation of the permanent and temporal habitat impacts of the Facility may be considered successful if the Applicant protects and enhances sufficient habitat to meet the ODFW goals of no net loss of habitat quantity or quality and a net benefit in habitat quantity or quality for impacts to Category 2 habitat, or provides commensurate funding. For Option 1 or 2, mitigation shall be considered successful in meeting the Applicant’s obligations at the time of payment to the third-party mitigation provider. For Option 3, the success will be based on improvement of habitat quality based on evidence of indicators such as survival of planted shrubs, natural recruitment of sagebrush, and successful weed control. However, much of the Category 2 habitat impacted by the Project was preliminarily identified as Category 3, 4, and 5 habitat based on vegetative characteristics such as presence of non-native species and was only designated as Category 2 habitat based on its value to wintering mule deer. As a result, habitat within the mitigation area will only need to be enhanced to the extent that it provides net benefit over the quality of habitat impacted by the Facility as it falls within ODFW-designated Mule Deer Winter Range. If the Applicant cannot demonstrate that the habitat mitigation area is trending toward the habitat...
quality goals described above within 5 years after the initial shrub planting, the Applicant would propose remedial action. ODOE may require supplemental planting or other corrective measures.

6.0 Pre-Construction Reporting

Prior to any phase of construction, the Certificate Holder shall provide to ODOE and ODFW a report identifying the mitigation option(s) selected to meet the Council's Fish and Wildlife Habitat standard for permanent and temporal habitat impacts. The report shall identify the mitigation ratio for permanent impacts, established within a range deemed acceptable of 1.1 to 1.5 acres per 1 acre impacted. The report shall confirm that temporal impacts would be mitigated at a ratio of 0.5 acres for every 1 acre temporarily impacted that is anticipated to take 5 or more years to recover.

The report shall specify the methodology for evaluating the habitat subtype/quality within the areas of permanent and temporal disturbance and within the mitigation sites for either or both Options 1 and 2, depending on final options selected for implementation.

The report shall identify the enhancement actions to be implemented at the mitigation site and shall provide the metrics necessary to evaluate enhancement action success.

7.0 Amendment of the HMP

This HMP may be amended from time to time by agreement of the Applicant and the Oregon Energy Facility Siting Council (Council). Such amendments may be made without amendment of the site certificate. The Council authorizes ODOE to agree to amendments to this HMP. ODOE shall notify the Council of all amendments, and the Council retains the authority to approve, reject, or modify any amendment of this HMP agreed to by ODOE.

8.0 References


ODFW. 2013. ODFW Winter Range for Eastern Oregon. GIS dataset available online at: https://nrimp.dfw.state.or.us/DataClearinghouse/default.aspx?p=202&XMLname=b85.xml

Attachment P-2.
Draft Habitat Mitigation Plan

Bakeoven Solar Project
December 2019

Prepared for
Avangrid Renewables, LLC

Prepared by
Tetra Tech, Inc.
**ATTACHMENT P-2. DRAFT HABITAT MITIGATION PLAN**

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Figure 1. Potential Mitigation Areas
1.0 Introduction

This Habitat Mitigation Plan (HMP) describes how Bakeoven Solar, LLC (Applicant) will mitigate for the unavoidable wildlife habitat impacts of the Bakeoven Solar Project (Facility). Specifically, this HMP\(^1\) outlines how the Applicant will construct and operate the Facility consistent with the Oregon Department of Fish and Wildlife (ODFW) Habitat Mitigation Policy. This plan addresses mitigation for both the permanent impacts of Facility components (permanent impacts) and the temporal impacts associated with the Facility construction (temporary impacts with a longer [5+ years] restoration timeframe). The Applicant proposes three mitigation options, including 1) mitigation banking with ODFW; 2) payment to provide option with Western Rivers Conservancy or Deschutes Land Trust; and 3) acquisition of a conservation easement to protect and enhance a compensatory mitigation area. As presented in the HMP, Option 1 is included to preserve a potential future mitigation option, but the Applicant acknowledges that the appropriate procedures necessary to support a mitigation banking program have not been adopted by ODFW. For Option 2, this Plan specifies the cost of property acquisition, restoration actions, and stewardship costs for long-term protection and management of a mitigation site. Option 3 is an Applicant-developed mitigation site; this plan specifies habitat enhancement actions and monitoring procedures to evaluate the success of those actions, as applicable. The Applicant anticipates that the Facility will be built in phases; therefore, the mitigation options may be used in combination or used in variation per phase (e.g., Option 3 for Phase 1, Option 2 for Phase 2, Option 1 and 2 for Phase 3, etc.).

2.0 Description of the Impacts Addressed by the HMP

The Facility is located entirely within the ODFW Designated Mule Deer Winter Range. ODFW (2013) describes Mule Deer Winter Range in eastern Oregon as limited and essential habitat for big game; therefore, should be considered as Category 2 under ODFW’s Habitat Mitigation Policy. It is not possible to site the Facility outside of the designated winter range because the Facility is interconnection dependent on its interconnection point at Bonneville Power Administraion’s Maupin Substation, which is also in Mule Deer Winter Range. Therefore, impacts to Category 2 are unavoidable due to the Facility’s interconnection location and the overlapping Mule Deer Winter Range.

Notwithstanding the overarching habitat categorization, the area within the micrositing corridor is primarily composed of eastside grassland (habitat types Upland Grassland, Shrub-Steppe and Shrubland; subtype Eastside Grassland) and planted grasslands, with smaller areas of shrub-steppe habitat (habitat types Upland Grassland, Shrub-Steppe and Shrubland; subtype Shrub-Steppe) that may be used by various species (Exhibit P, Tables P-2 and P-3). Essential habitat values for quality big game winter range, such as thermal cover, security from predation and harassment, quality forage, and limited disturbance are generally lacking from the micrositing corridor because it is

\(^{1}\)This HMP will be incorporated by reference in the site certificate for the Bakeoven Solar Project and must be understood in that context. It is not a "stand-alone" document.
mostly composed of planted grassland and highly disturbed native grassland (Exhibit P, Section 8.1.1).

As presented in Exhibit P, no areas of native eastside grassland or shrub-steppe habitat were field-characterized in 2018 as Category 2 habitat. Planted grasslands ranging from Categories 3-5 account for 948.4 acres (22.8 percent) of the micrositing corridor. Areas of eastside grassland and shrub-steppe habitat dominated by non-native plant species (Categories 4 and 5) comprise 1762.1 acres (42.3 percent) of the micrositing corridor (see Exhibit P, Tables P-3 and P-4). The remaining areas of eastside grassland and shrub-steppe have a higher native species composition (Category 3), and comprise 997.2 (23.9 percent) acres of the micrositing corridor.

Permanent impact areas are those that would be converted from the existing condition to a different condition for the life of the Facility. Solar array areas will be fenced, and all areas inside the fence are considered permanently disturbed. In addition to the solar array, fencing will occur at the collector substation, the operations and maintenance (O&M) building, and the battery storage area, as required by electrical code or security needs (see Application for Site Certificate [ASC] Exhibits B and C). Temporary impacts will be fully mitigated through successful implementation of the Revegetation Plan (Attachment P-3 to Exhibit P). However, some areas of shrub-steppe that will be temporarily impacted include sagebrush stands that could take longer than 5 years to be restored. Even where restoration of this habitat subtype is successful, there is a loss of habitat function during the restoration period. Therefore, this HMP includes mitigation for both permanently impacted habitat (2,473.0 acres) and select areas of temporarily impacted shrub-steppe habitat (shrub-steppe subtype: 32.0 acres) that results in a temporal loss of habitat quality (Table 1).

The Facility will not have any impacts on Category 1 habitat. In accordance with ODFW’s Habitat Mitigation Policy, impacts to Category 6 habitat do not require mitigation. All remaining Category 3, 4, and 5 habitat has been re-categorized as Category 2 habitat because the Facility is within ODFW’s Designated Mule Deer Winter Range, which overlaps the areas of temporary and permanent impact (ODFW 2013). Based on this definition, Table 1 presents anticipated acres of impact for Category 2 habitat present at the Facility, in addition to the preliminary habitat categorization of these areas before the application of this overlay.

Table 1. Acres of Impact to Habitat Categories and Types within the Proposed Micrositing Corridor

<table>
<thead>
<tr>
<th>Final Habitat Category¹</th>
<th>Preliminary Habitat Category</th>
<th>Habitat Type-Subtype²</th>
<th>Permanent Impact</th>
<th>Temporary Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>3</td>
<td>Riparian Forest and Natural Shrubland Complexes – Eastside Riparian</td>
<td>0.6</td>
<td>1.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Eastside Grassland</td>
<td>579.1</td>
<td>14.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe</td>
<td>103.4</td>
<td>32.0³</td>
</tr>
</tbody>
</table>

³Temporary loss of habitat quality.
ATTACHMENT P-2. DRAFT HABITAT MITIGATION PLAN

<table>
<thead>
<tr>
<th>Final Habitat Category</th>
<th>Preliminary Habitat Category</th>
<th>Habitat Type-Subtype</th>
<th>Permanent Impact</th>
<th>Temporary Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Agriculture, Pasture, Mixed Environments - Planted Grassland</td>
<td>423.4</td>
<td>16.2</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Cliffs, Caves, and Talus</td>
<td>0.0</td>
<td>0.4</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Open Water - Lakes Rivers Streams - Seasonal Pond</td>
<td>0.7</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Open Water - Lakes Rivers Streams - Intermittent or Ephemeral Streams</td>
<td>0.0</td>
<td>&lt;0.1</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Upland Grassland, Shrub-Steppe and Shrubland - Eastside Grassland</td>
<td>792.3</td>
<td>17.0</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Upland Grassland, Shrub-Steppe and Shrubland - Shrub-Steppe</td>
<td>1.8</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Agriculture, Pasture, Mixed Environments - Planted Grassland</td>
<td>177.1</td>
<td>7.3</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Upland Grassland, Shrub-Steppe and Shrubland - Eastside Grassland</td>
<td>303.4</td>
<td>17.4</td>
<td></td>
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<tr>
<td>5</td>
<td>Upland Grassland, Shrub-Steppe and Shrubland - Shrub-Steppe</td>
<td>91.1</td>
<td>47.6</td>
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<tr>
<td>5</td>
<td>Upland Forests and Woodlands - Juniper Woodland</td>
<td>0.0</td>
<td>2.6</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Agriculture, Pasture, Mixed Environments - Planted Grassland</td>
<td>0.1</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Category 2 Final Total</td>
<td></td>
<td><strong>2,473.0</strong></td>
<td><strong>157.6</strong></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Agriculture, Pasture, Mixed Environments - Orchards, Vineyards, Wheat Crops and Other Row Crops</td>
<td>240.4</td>
<td>4.3</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Urban and Mixed Environments</td>
<td>3.6</td>
<td>14.7</td>
<td></td>
</tr>
<tr>
<td>Category 6 Final Total</td>
<td></td>
<td><strong>244.0</strong></td>
<td><strong>19.0</strong></td>
<td></td>
</tr>
<tr>
<td>Grand Total</td>
<td></td>
<td><strong>2,717.0</strong></td>
<td><strong>176.6</strong></td>
<td></td>
</tr>
</tbody>
</table>

Note: Totals in this table may not be precise due to rounding.

1. Final Category following application of ODFW Designated Mule Deer Winter Range overlay.
2. Only impacted Habitat Types-Subtypes present within the proposed micrositing corridor are represented.
3. Temporarily impacted shrub-steppe habitat.

The Applicant proposes to begin construction as soon as June 2020, and to construct the Facility in phases. The size and construction schedule for each phase will be based on market demand, but the entire Facility, including all phases, will be completed by 2026 unless the Applicant seeks an amendment to extend the construction deadline. Table 2 provides an example phased construction schedule. The impact analysis presented in the ASC and mitigation outlined in this HMP represents the fully built-out scenario of 303 megawatts. Mitigation will be determined prior to the
construction of each phase. If phases are transferred to a new Certificate Holder, then any mitigation obligations will also be transferred. For example, if a mitigation site is established for Phase 1 (i.e., Option 3) then the real estate rights (e.g., conservation easement), monitoring requirements, and liability of obtaining success criteria would be transferred to the new Certificate Holder. If the original Certificate Holder satisfies the mitigation obligation using payment-to-provide mitigation (i.e., Options 1 or 2) then the mitigation obligation for any future owner would be complete. A Site Certificate transfer would require approval by EFSC, so there is ability to verify mitigation status during a transfer of ownership.

Table 2. Example Construction Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>Final engineering and begin construction.</td>
</tr>
<tr>
<td>2021</td>
<td>Phase 1 construction and operation.</td>
</tr>
<tr>
<td>2022</td>
<td>Phase 2 construction and operation.</td>
</tr>
<tr>
<td>2023/2024</td>
<td>Phase 3 construction and operation.</td>
</tr>
<tr>
<td>2026</td>
<td>Construction completion deadline for all phases.</td>
</tr>
</tbody>
</table>

3.0 Methods for Calculating the Size of the Mitigation Area

The mitigation area will be determined for each phase of the Facility based on the final design for that phase and actual habitat impacts (i.e., Category 2 vs. Category 6 habitat). Before beginning construction of each phase of the Facility, the Applicant will provide the Oregon Department of Energy (ODOE) with a map showing the final design configuration for that phase of the Facility, and a table showing the estimated acres of permanent and temporary impacts by habitat category (Table 1). Mitigation calculations for each phase will be based on current habitat conditions that will be mapped and field verified by the Applicant no earlier than 2 years prior to construction of each phase.

Current habitat conditions will be used to calculate the size of the mitigation area using the mitigation ratios presented in Table 3. Use of these mitigation ratios will ensure that the mitigation area is large enough to achieve “no net loss” of habitat quantity or quality and that a “net benefit” in habitat quantity or quality is provided. In addition, all mitigation options described below include a habitat enhancement component through either payment to third-party or restoration actions performed by the Applicant. Therefore, implementation of this HMP will result in habitat mitigation that is consistent with the ODFW Habitat Mitigation Policy.
Table 3. Compensatory Mitigation Ratios

<table>
<thead>
<tr>
<th>Final Habitat Category</th>
<th>Current Habitat Category</th>
<th>Mitigation Ratio Permanent</th>
<th>Mitigation Ratio Temporary</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>2</td>
<td>1.5:1</td>
<td>0.5:1 for Shrub Steppe habitat</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>1.3:1</td>
<td>0.5:1 for Shrub Steppe habitat</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>1.2:1</td>
<td>None</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>1.1:1</td>
<td>None</td>
</tr>
<tr>
<td>6</td>
<td>6</td>
<td>None</td>
<td>None</td>
</tr>
</tbody>
</table>

1. Final Category following application of ODFW Designated Mule Deer Winter Range overlay.
2. Current habitat condition and category as mapped by the Applicant prior to construction.
3. Permanent impact areas based on final design and includes the Facility’s footprint. No mitigation offered for Category 6 habitat.
4. Compensatory mitigation for temporal habitat loss to current Category 2 or 3 Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe sub-habitat type (see Table 1). Other habitat types will be restored following the methods described in the Revegetation Plan.

For temporal impacts that require mitigation, the mitigation area will include up to 0.5 acres for every 1 acre of Upland Grassland, Shrub-Steppe and Shrubland – Shrub-Steppe sub-habitat type that is temporary affected by construction activities (but outside the Facility footprint). The size of this portion of the mitigation area assumes that restoration of disturbed eastside grassland and shrub-steppe habitat is successful, as determined under the Revegetation Plan (Attachment P-3 to Exhibit P). Additional mitigation may be needed if restoration efforts of other habitat types is unsuccessful.

Because the Facility will be constructed in phases, it is assumed that compensatory mitigation will be based on the new impacts of each phase, and there would be no double counting of impacts associated with shared facilities with prior phases (e.g., shared transmission line or substation).

4.0 Mitigation Options

The Applicant has identified three options for addressing the mitigation obligation where habitat protection and enhancement and/or commensurate funding are feasible and consistent with this HMP. Each option is located within the Columbia Plateau and “in proximity” to the Facility. The Applicant may use one option or a combination of options to mitigate for habitat impacts, and will determine the combination of the mitigation options that best correlate to the impacted areas in consultation with ODFW and the affected landowners, subject to ODOE’s approval. As described above, Option 1 is not an available mitigation option at the time of ASC review and approval; but the Applicant preserved the right to use Option 1 should it be available in the future.

The final mitigation approach will offer enough suitable habitat to achieve the ODFW goal of no net loss of habitat quantity or quality, and provide a net benefit in habitat quantity. As the potential mitigation locations are within ODFW-mapped Mule Deer Winter Range, acquisition of these areas constitutes Category 2 habitat regardless of the habitat condition and thus meets the ODFW goal of...
no net loss of habitat quantity; any enhancement actions successfully performed would result in a net benefit in habitat quality. Prior to operation of the Facility, or a particular phase of the Facility, the Applicant will acquire the legal right to create, maintain, and protect the habitat mitigation area for the life of the Facility by means of an outright purchase, conservation easement, or similar conveyance, and will provide a copy of the documentation to ODOE. The duration of mitigation Option 1 and Option 2 would be in perpetuity (i.e., permanent conservation of habitat), whereas the duration of Option 3 would be limited to the life of the Facility (i.e., a limited term).

4.1 Option 1: ODFW Payment-to-Provide

The Applicant understands that ODFW is considering a payment-to-provide program that could be used to mitigate habitat impacts related to energy facilities. However, at this time, this program is not yet available. Should such a program become available in the future, the Applicant could use a payment-to-provide mitigation option with the approval of ODOE and ODFW.

4.2 Option 2: Third-Party Payment-to-Provide

Under this option, the Applicant would partner with either Western Rivers Conservancy (Option 2a) or the Deschutes Land Trust (Option 2b) in land acquisition for the purpose of habitat protection and restoration. This mitigation option has the ability to achieve landscape-level habitat protection because the Applicant would partner with a land trust on a larger mitigation project. The Applicant believes this mitigation option offers substantial benefits to mule deer because it enables more winter range to be protected than a traditional, stand-alone mitigation site (Option 3).

The Applicant would meet its mitigation obligation by providing a one-time payment to the third-party mitigation provider prior to commercial operation of the Facility, or phase of the Facility. The payment would take into consideration the cost of property acquisition for the mitigation area (i.e., Land Costs), habitat improvement actions (i.e., Restoration Action Costs or Habitat Enhancement Actions), maintenance and monitoring for long-term protection and management of the site (i.e., Stewardship Costs). The following formula would be used to determine the total mitigation payment:

$$\text{Mitigation cost per acre} = M \times (R + L + V + S)$$

Where:

- $M$ = Mitigation ratio as defined in Section 3
- $R$ = Restoration costs per acre + contract administration costs to implement restoration
- $L$ = Restoration maintenance costs per acre
- $V$ = Land value per acre. Land costs of the mitigation site based on the appraised land value, actual costs, or a value determined by the third-party mitigation provider

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2 As used in this Plan, "life of the facility" means continuously until the Facility site is restored and the site certificate is terminated in accordance with Oregon Administrative Rules 345-027-0110.
• $S =$ Stewardship endowment costs per acre, determined by the third-party mitigation provider

The two mitigation opportunities are considered “in-kind” mitigation, as both mitigation sites are within the ODFW-mapped Mule Deer Winter Range, and each site has grassland and shrub-steppe habitat types that are similar to the Facility’s micrositing corridor. Because the equation above assumes a proportional payment to the acquisition and maintenance of the third-party’s mitigation site, no specific habitat assessment of the mitigation site will be provided.

Prior to the construction, the Applicant would provide ODOE with a Memorandum of Understanding (MOU) between the Applicant and the third party mitigation provider that that documents the transaction, confirms the applicability of the above mitigation equation, and includes a copy of the mitigation site’s management plan. The management plan will be prepared by the third-party and would describes the long-term management goals and monitoring program for the mitigation site. The Applicant will request that the management plan acknowledge that the monitoring reports be available for ODOE review.

The Applicant has identified two partners, Western River Conservancy and Deschutes Land Trust, that both have near-term plans for large scale habitat conservation projects in Wasco County. This HMP assumes that either option (e.g., Option 2a, or Option 2b) could be executed prior the operation of any Facility phase; if the third-party has not closed on the purchase of the mitigation site prior to construction, then this option is not feasible.

4.2.1 Option 2a. Western Rivers Conservancy

Under Option 2a, the Applicant would contribute funds to Western Rivers Conservancy that would be used to support the purchase of lands along the John Day River in Wasco County. The subject parcel is a former ranch located along the lower John Day River that includes about 30,000 acres and is at risk of being subdivided into smaller parcels because the landowner plans to sell the property. The Applicant’s contributions would support Western River Conservancy’s purchase for the entire property and maintain this large continuous area as a single tract. Western River Conservancy is currently negotiating the purchase terms with the landowner and the exact location of the mitigation site is not publicly available at this time.

The land would be eventually transferred to the Bureau of Land Management (BLM) and added to the John Day River Wild and Scenic Designation. BLM would manage the land under its John Day Basin Resources Management Plan3, which includes management objectives to maintain or improve winter range for deer and elk (Objective W1) and special considerations for areas within Wild and Scenic River designations. Western Rivers Conservancy would transfer land to the BLM depending on the availability of Land and Water Conservation Funds allocated by the U.S. Congress. Western Rivers Conservancy will manage and maintain the lands until this transfer occurs. During this interim period, Western River Conservancy would implement an interim management plan that

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Commented [A5]: ODFW JT Comment: ODFW has conducted site visits to both proposed mitigation sites and concurs that conditions are equal or greater at both sites, and with proposed uplift by the applicant will mitigate not only Cat 2 winter range but also existing habitat conditions found at the development site.
precludes cattle grazing, limits public access to foot access only, and potentially includes removing structures.

BLM’s John Day Basin Resource Management Plan allows for mineral and energy extraction in the planning area but these activities are not allowed within land within Wild and Scenic River designation. The land acquisition deal is structured to preclude future mineral development. There are no executed mineral leases on the property, but Western Rivers Conservancy is aware of three outstanding mineral reservations. At part of its due diligence, Water River Conservancy will complete a third-party evaluation of mineral resources potential to assess the actual resources and feasibility for future mineral development. If this evaluation indicates a possibility of mineral development, then Western Rivers Conservancy will offer to purchase the mineral reservations or rights, and work with the BLM to expressly preclude mineral development in documents (e.g., National Environmental Policy Act documents) prepared for the land transfer. Based on this approach, the Applicant believes there is little chance of future mineral development that could affect the mitigation lands associated with the Facility. Additionally, by law, all property acquired by federal agencies utilizing a Land and Water Conservation Fund appropriation must be managed for conservation and may not be sold.

The Western Rivers Conservancy mitigation option would benefit wintering deer, as robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of winter deer habitat (ODFW 2011). During severe winters, snow can cover annual grasses and native bunch grasses, so access to nutritious woody vegetation (i.e., shrubs) is essential to overwinter survival (ODFW 2011).

Western River Conservancy will monitor the mitigation site per the terms of its interim management plan, which will be provided to ODOE by the Applicant. Once transferred to BLM, then monitoring needs and objectives would follow BLM’s resources management plan. But over time, Western Rivers Conservancy would revisit the mitigation site to verify that the goals of the original project have been met. This assessment could include researching the background of the project, conducting field inspections, interviewing current land managers and other people with an interest in the property.

4.2.2 Option 2b. Deschutes Land Trust

Under Option 2b, the Applicant would contribute funds to the Deschutes Land Trust for the acquisition and management of a 5,820-acre property in south Wasco County, known as the Trout Creek Preserve. The Deschutes Land Trust would own and maintain this site, with an overlapping conservation easement held by the Oregon Watershed Enhancement Board (OWEB). The Trout Creek Preserve is within the ODFW-defined winter range for mule deer and elk. Similar to the Western Rivers Conservancy mitigation option, the Deschutes Land Trust mitigation option would

Commented [A6]: BDFW JT Comment: We still need to come to an agreement on allowing mitigation to occur on BLM. The logic laid out by Avangrid here is sound, can we include in our comments that should conditions change in a manner that is detrimental the applicant will have to revisit mitigation? I honestly feel it may be easier to work with BLM than to try to enforce a conservation easement on private land. I have no idea who is monitoring those easements now.

Commented [A7R6]: SARAH COMMENT: IF they are able to get the BLM to take the property without mineral rights, IF there are restrictions on grazing beyond normal BLM range management policies, and IF they are able to protect the conservation values either through LWCF funding restrictions or through a Wild and Scenic designation, THEN we are willing to allow mitigation on BLM lands. I have run all those IF’s by Division, so I know we have agreement. But I think the chances of all those IF’s aligning will be slim to none. I just hope WRC is willing to hold onto those mitigation acres if the deal doesn’t pan out!

*See [http://www.westernrivers.org/projectatlas/stewardship/](http://www.westernrivers.org/projectatlas/stewardship/)*
benefit wintering deer as robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of winter deer habitat (ODFW 2011).

The Deschutes Land Trust would develop a management plan for the Trout Creek Preserve with input from ODFW, and conservation objectives will focus on stream protection and rangeland improvements. Monitoring would consist of assessing habitat conditions, taking photos or acquiring aerial imagery to compare with previous/baseline photos, looking at the success of various treatments, and checking for misuse of or damage to the property. Deschutes Land Trust has a stewardship program respond to issues on the mitigation site on a regular basis, such as minor weed encroachments, fence repairs, or dealing with human trespass issues. Deschutes Land Trust would conduct annual monitoring for the entire Trout Creek Preserve, and would update its management plan every 5 years based on monitoring results and opportunities for adaptive management. The MOU between the Applicant and Deschutes Land Trust will specific that the updated management plans be provided to ODOE when available (i.e., every 5 years).

4.3 Option 3: Conservation Easement Lands Adjacent to the Facility

Under this option, the Applicant would establish conservation easements adjacent to the Facility. In consultation with participating landowners, the Applicant has identified two areas that could be used for mitigation sites. First, the A&K Ranch site includes multiple parcels totaling 2,428 acres (Figure 1). Second, the Maupin Opportunity Area is a larger area about 40,322 acres southwest of the Facility (Figure 1). Both areas are within the ODFW-defined Mule Deer Winter Range and have enhancement opportunities beneficial to big game and grassland birds.

Some of the parcels of the A&R Ranch site are along Bakeoven Creek and contiguous with land managed by the BLM, providing an opportunity for integrated enhancement over a larger area. As described above under Option 2, robust riparian vegetation with a high diversity of woody shrub species along streams is an important component of deer winter habitat. The Oregon Mule Deer Initiative (ODFW 2011) identified these types of habitats as highly impacted compared to historical conditions, noting that riparian areas have been degraded and often lack quantity and diversity of shrub species. Therefore, enhancement of riparian habitat along Buck Hollow Creek would benefit wintering mule deer.

The second mitigation area is known as the Maupin Opportunity Area and was recommended by ODFW for consideration by the Applicant in an August 2019 meeting (Figure 1). The property is proximate to the site boundary, provides ample potential acreage, and is composed of similar habitat types suitable for in-kind mitigation. A portion of the property is located immediately south of Bakeoven Road, near the westernmost section of the proposed transmission line. Habitat in this area was desktop delineated (as shown in Exhibit P Figure P-4) as primarily shrub-steppe and planted grassland habitat, with intermittent riparian, wetland, and developed areas. Much of the area shown in the figure was within the boundary of the 2018 Boxcar Fire. Areas to the north of Bakeoven Road were not impacted by this disturbance. Per ODFW (pers. comm., Jeremy Thompson, August 19, 2019), before the fire, the habitat with the Maupin Opportunity Area was similar to habitat within the site boundary; however, its condition following fire disturbance and a year of
recovery time is unknown. Per ODFW, this area likely offers opportunities for upland and grassland habitat restoration, to mitigate for permanent and temporary impacts to grassland habitats due to the construction and operation of the Facility (Table 1). Enhancement of grassland habitat in this area would potentially improve forage quality for wintering mule deer and offer improved conditions for grassland bird species as well.

Per ODFW request (pers. comm., Jeremy Thompson, August 19, 2019), the Applicant has performed a desktop analysis of the remainder of the approximately 40,322-acre area. Using pre-fire imagery via Google Earth, the Applicant confirmed that the property appears to be primarily a mix of upland grasslands (some appear to be planted), and a mosaic of shrublands and grasslands. Pre-fire, junipers were encroaching on these shrub-steppe habitats from lower-elevation draws and possible riparian areas, but the condition of these trees post-fire is unknown. If Option 3 is pursued, the Applicant will continue to work with ODFW to identify opportunities to protect and enhance habitats in this area, and to define the appropriate monitoring of mitigation parcels. Prior to construction, the Applicant will provide an updated desktop analysis to confirm the habitat subtype within the mitigation parcel(s).

### 4.3.1 Habitat Enhancement Actions

If Option 3 is selected, the Applicant will develop a management plan for the selected mitigation site that includes habitat enhancement actions to improve the habitat conditions of the mitigation site. The objectives of habitat enhancement are to protect habitat within the mitigation area from degradation and to improve the habitat quality of the mitigation area. By achieving these objectives, the Applicant can address the permanent and temporal habitat impacts of the Facility and meet the ODFW goals of no net loss of habitat quantity or quality and a net benefit in habitat quantity or quality for impacts to Category 2 habitat. The Applicant may choose one or more of the following enhancement actions based on the needs of the selected habitat mitigation area to improved habitat conditions, as appropriate and feasible:

1. **Shrub Planting**. The Applicant would plant sagebrush or other native shrubs in locations within the habitat mitigation area where existing native shrubs are stressed, or where recent wildfires have occurred. The Applicant would determine the size (including number of shrubs and age of shrubs – seedlings or transplanted mature plants) of the shrub-planting areas and the shrub species based on the professional judgment of a qualified biologist after a ground survey of actual conditions. The size of the shrub-planting areas will depend on the size of the available mitigation area and opportunity for survival of planted shrubs. If appropriate, other native shrubs may include antelope bitterbrush (*Purshia tridentata*), golden currant (*Ribes aureum*), and winterfat (*Krascheninnikovia lanata*). The shrub survival rate at 4 years after planting is an indicator of successful enhancement of habitat quality to Category 2. The Applicant would complete the initial shrub planting within 1 year after the beginning of construction of the Facility, or a particular phase of the Facility. Supplementing existing, but disturbed, sagebrush areas with sagebrush seedlings or transplanted mature plants would assist the restoration of this valuable shrub-steppe
component. The Applicant would obtain shrubs from a qualified nursery, and would identify the area to be planted with sagebrush or other native shrubs after consultation with ODFW, subject to final approval by ODOE. The Applicant would mark the planted shrub clusters at the time of planting for later monitoring purposes, and would keep a record of the number of shrubs planted. Plantings would generally be considered successful if a 20 percent survival rate is achieved after 4 years.

2. **Weed Control.** The Applicant would implement a weed control program. Under the weed control program, the Applicant would conduct a pre-management weed assessment to identify the type and percentage of non-native species within the mitigation area. The Applicant would then monitor the mitigation area to locate weed infestations. The Applicant would continue weed control monitoring, as needed, for the life of the Facility. As needed, the Applicant would use appropriate methods to control weeds. Appropriate weed control methods shall include identification of noxious weeds within the mitigation area, timing, herbicides, and application mechanism and be based on consultation with the county weed control authority. Weed control on the mitigation site will reduce the spread of noxious weeds within the habitat mitigation area and on any nearby grassland, Conservation Reserve Program or cultivated agricultural land. Weed control will promote the growth of desirable native vegetation and planted sagebrush. The Applicant may consider weeds to be successfully controlled when weed clusters have been eradicated or reduced to a non-competing level. Weeds may be controlled with herbicides or hand-pulling. The Applicant would notify the landowner of the specific chemicals to be used on the site and when spraying will occur. To protect locations where young desirable forbs may be growing, spot-spraying may be used instead of total area spraying.

3. **Seeding.** The Applicant would plant an ODFW-approved seed mix within the habitat mitigation area in areas that have been recently disturbed (e.g., recent wildlife or weed treatment). The method for seed application would be determined primarily based on the size of the area to be seeded. The size of the seeded area will depend on the amount of recently disturbed area within the mitigation area. The Applicant would complete the initial seeding within 1 year after the beginning of construction of the Facility, or a particular phase of the Facility. The Applicant would record and mark the seeded areas at the time of seeding for later monitoring purposes.

4. **Fire Control.** The Applicant would implement a fire control plan for wildfire minimization when Facility staff are working within the mitigation area. The Applicant would provide a copy of the fire control plan to ODOE before starting habitat enhancement actions. The Applicant would include in the plan appropriate fire prevention measures, methods to detect fires that may occur and a protocol for fire response if a fire were to occur when Project staff were present. If any part of the mitigation area is damaged by future wildfire, the Applicant would assess the extent of the damage and implement appropriate actions to restore habitat quality in the damaged area.

Commented [A8]: SARAH COMMENT: Consider a more quantitative measurement and threshold, and by what year.

Commented [A9]: SARAH COMMENT: This, and the remaining restoration actions (maybe aside from fire control) needs quantitative success criteria.
5. **Riparian Planting.** The Applicant would plant appropriate riparian species along streams to enhance these riparian areas, if present, for the benefit of fish and big game. Riparian plantings will improve access to nutritious woody vegetation for wintering deer, which is essential to over-winter survival during severe winters when annual grasses and native bunchgrasses are covered in snow. Riparian plantings will improve shading of streams, which will improve temperature conditions for fish at the location of plantings, as well as downstream. Riparian plantings will also provide cover for big game and help stabilize soil.

6. **Fence Building.** The Applicant would build fencing around the riparian plantings to reduce grazing pressure and allow riparian vegetation to grow. Fencing would be designed to exclude cattle but not deer. Woody vegetation is used by deer for foraging in the winter and provides cover for insulation and hiding.

7. **Juniper Removal.** Where appropriate, the Applicant would remove encroaching juniper to increase the amount of sunlight, moisture, and nutrients available for shrubs and forbs used by mule deer.

8. **Habitat Protection.** The Applicant would restrict uses of the mitigation area that are inconsistent with the goals of no net loss of habitat quantity or quality and a net benefit in Category 2 habitat quantity or quality.

Table 4 outlines the anticipated costs and benefits of various enhancement actions, as well as the anticipated cost of operations and maintenance.

**Table 4. Estimated Restoration Cost Per Unit and Benefit to Mule Deer Winter Range**

<table>
<thead>
<tr>
<th>Type</th>
<th>Action</th>
<th>Cost per Unit</th>
<th>Units</th>
<th>Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhancement</td>
<td>Shrub Planting</td>
<td>$136.95 †</td>
<td>Per acre</td>
<td>Provide access to nutritious woody vegetation during winter, especially severe winters when snow covers grass forage, in order to improve over-winter survival. Deer on winter ranges without a shrub component often have high rates of over-winter mortality (ODFW 2011).</td>
</tr>
<tr>
<td></td>
<td>Biological, Chemical, or Mechanical Weed treatment</td>
<td>$8.81 - $257.73 †</td>
<td>Per acre</td>
<td>Reduce competition with desirable forage species to improve or maintain mule deer forage quality and quantity. Impacts of invasive species on Oregon’s fish and wildlife resources are one of the seven most pressing conservation issues identified in the Oregon Conservation Strategy (ODFW 2016).</td>
</tr>
</tbody>
</table>
### 4.3.2 Monitoring

For Option 3 (Conservation Easement), the Applicant will hire a qualified investigator (botanist, wildlife biologist, or revegetation specialist) to conduct a comprehensive monitoring program for the mitigation area, as appropriate. The purpose of this monitoring is to evaluate on an ongoing
basis the protection of the habitat quality and the results of enhancement actions, especially during the winter and wildlife breeding seasons.

The investigator will monitor the habitat mitigation area for the life of the Facility beginning in the year following the initial planting. Monitoring will occur annually during the first 10 years following initial planting, then will occur every 3 years thereafter. The Applicant will identify appropriate monitoring actions for the Conservation Easement and the habitat enhancement actions that are implemented in consultation with ODOE and ODFW. Depending upon specific habitat enhancement actions implemented, the investigator may carry out the following monitoring procedures:

1. Assess vegetation cover (species, structural stage, etc.) and progress toward meeting the success criteria;
2. Record environmental factors (such as precipitation at the time of surveys and precipitation levels for the year);
3. Record any wildfire that occurs within the mitigation area and any remedial actions taken to restore habitat quality in the damaged area;
4. Assess the success of the weed control program and recommend remedial action, if needed; and
5. Assess the survival rate and growth of planted species.

The investigator will visit identified monitoring points within planted areas. Plantings will generally be considered successful if a 20 percent survival rate is achieved after 4 years. The investigator will report on the timing and extent of any livestock grazing that has occurred within the mitigation area since the previous monitoring visit.

### 5.0 Success Criteria

Mitigation of the permanent and temporal habitat impacts of the Facility may be considered successful if the Applicant protects and enhances sufficient habitat to meet the ODFW goals of no net loss of habitat quantity or quality and a net benefit in habitat quantity or quality for impacts to Category 2 habitat, or provides commensurate funding. For Option 1 or 2, mitigation shall be considered successful in meeting the Applicant’s obligations at the time of payment to the third-party mitigation provider. For Option 3, the success will be based on improvement of habitat quality based on evidence of indicators such as survival of planted shrubs, natural recruitment of sagebrush, and successful weed control. However, much of the Category 2 habitat impacted by the Project was preliminarily identified as Category 3, 4, and 5 habitat based on vegetative characteristics such as presence of non-native species and was only designated as Category 2 habitat based on its value to wintering mule deer. As a result, habitat within the mitigation area will only need to be enhanced to the extent that it provides net benefit over the quality of habitat impacted by the Facility as it falls within ODFW-designated Mule Deer Winter Range. If the Applicant cannot demonstrate that the habitat mitigation area is trending toward the habitat

Commented [A12]: ODFW JT Comment: So with Option 2, I feel that there must be an assurance of acknowledgement from DLT or WRC that should uplift measures fail, ODFW will recommend to ODOE remedial action.

Commented [A13]: SARAH COMMENT: This is inadequate. Specific, quantitative success criteria are needed for the restoration actions. Also need to clarify who is on the hook if the uplift fails to meet criteria, or if the quality begins to underperform over time.
quality goals described above within 5 years after the initial shrub planting, the Applicant would propose remedial action. ODOE may require supplemental planting or other corrective measures.

6.0 Pre-Construction Reporting

Prior to any phase of construction, the Certificate Holder shall provide to ODOE and ODFW a report identifying the mitigation option(s) selected to meet the Council’s Fish and Wildlife Habitat standard for permanent and temporal habitat impacts. The report shall identify the mitigation ratio for permanent impacts, established within a range deemed acceptable of 1.1 to 1.5 acres per 1 acre impacted. The report shall confirm that temporal impacts would be mitigated at a ratio of 0.5 acres for every 1 acre temporarily impacted that is anticipated to take 5 or more years to recover.

The report shall specify the methodology for evaluating the habitat subtype/quality within the areas of permanent and temporal disturbance and within the mitigation sites for either or both Options 1 and 2, depending on final options selected for implementation.

The report shall identify the enhancement actions to be implemented at the mitigation site and shall provide the metrics necessary to evaluate enhancement action success.

7.0 Amendment of the HMP

This HMP may be amended from time to time by agreement of the Applicant and the Oregon Energy Facility Siting Council (Council). Such amendments may be made without amendment of the site certificate. The Council authorizes ODOE to agree to amendments to this HMP. ODOE shall notify the Council of all amendments, and the Council retains the authority to approve, reject, or modify any amendment of this HMP agreed to by ODOE.

8.0 References


ODFW. 2013. ODFW Winter Range for Eastern Oregon. GIS dataset available online at: https://nrimp.dfw.state.or.us/DataClearinghouse/default.aspx?p=202&XMLname=885.xml

Hi Sarah,
Looking forward to seeing you today. Please find a new comment from the SAG attached to this email. It is with regards to emergency services available in the project area. We can discuss in greater detail this afternoon if you like.

Thanks and safe travels,
Angie

Angie Brewer, AICP | Director
PLANNING DEPARTMENT
angieb@co.wasco.or.us | www.co.wasco.or.us
541-506-2566 | Fax 541-506-2561
2705 East Second Street | The Dalles, OR 97058

This correspondence does not constitute a Land Use Decision per ORS 197.015. It is informational only and a matter of public record.
February 25, 2020

Sarah T. Esterson
Senior Siting Analyst
550 Capitol St. NE | Salem, OR 97301
(Sent to: Sarah.Esterson@oregon.gov)

Subject: Comments on Draft Proposed Order for the Bakeoven Solar Project

Dear Ms. Esterson,

The On behalf of Wasco County Special Advisory Group, please accept the following comments on the Draft Proposed Order for the Bakeoven Solar Project. The applicant’s efforts to respond to prior SAG comments are appreciated. Very recently, however, the project area ambulance services have been rendered insufficient. As a result, ambulance services cannot be relied upon to satisfy emergency medical needs.

Based on feedback received from the Wasco County Sheriff, Wasco County Emergency Management Services Manager, and the Wasco County 911 Operations Manager, the following must be provided to sufficiently address the emergency medical needs of the project site and associated workers:

- The applicant must provide their own emergency medical services and transport. Maupin ASA has authority over medical services rendered or provided within their ASA boundaries; the applicant must enter into an agreement with Maupin ASA and meet local requirements.
- Emergency medical services and transport should be provided by the applicant for the entire construction phase, not just peak labor times.
- The 911 Operations Manager must be notified when construction begins, with location information, so safety personnel can anticipate need and respond as efficiently as possible.
Thank you for your help to ensure the emergency response needs of our community are acknowledged and addressed. Please contact me directly with any questions or concerns. I can be reached at angieb@co.wasco.or.us or (541) 506-2566 Monday through Friday.

Sincerely,

Angie Brewer, AICP
Planning Director

CC: Wasco County Board of Commissioners
    Wasco County Administrative Officer, Tyler Stone
    Wasco County Sheriff, Lane Magill
    Wasco County Emergency Management Officer, Sheridan McClellan
    Wasco County 911 Operations Manager, Joe Davitt
Oregon Department of Energy and
the Energy Facility Siting Council
Public Hearing on the Draft Proposed Order
for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory)  
Brigette McConville

Mailing Address (mandatory)  
P.O. Box 989 Warm Springs OR 97761

Phone Number (optional)  

Email Address (optional)  

Today's Date: 2/25/2020

Do you wish to make oral public testimony at this Hearing:  Yes  No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

Note: by submitting written or oral testimony, you will receive a notice from the Oregon Department of Energy at a future date of the opportunity to request party status in a contested case hearing on the proposed facility.

Written Testimony
(Please print legibly – Use the back for additional space if needed. Additional written comments may be attached to this card.)

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Name (mandatory) Myra Johnson-Orange

Mailing Address (mandatory) 1898 S 584
Waim Springs OR 97961

Phone Number (optional) 971-460-0672 Email Address (optional) myra.johnson@oroostibes.org

Today's Date: 2-24-20

Do you wish to make oral public testimony at this Hearing: Yes [ ] No [ ]

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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LOCATION OF SOLAR PROJECT IS ON
Confederated Tribes of Warm Springs ceded lands
and areas that has our sacred/Traditional
 Foods (roots). foods that we have gathered
since time immorial. And today – no one
knows the impact the Solar projects will
have 5-10 or 20 years from now.
Tribal People would like to know
that our children's children—7 generations
from now—will have the same foods
as our ancestors enjoyed in the past.

Thank you.

What has been done regarding
cultural/archeology analysis
of area X.
Oregon Department of Energy and the Energy Facility Siting Council

Public Hearing on the Draft Proposed Order for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory)                      Robert A Krein

Mailing Address (mandatory)           PO Box 158
                                        Marpin, OR 97037

Phone Number (optional) (541) 815-0711 Email Address (optional) Kreinconsulting@yahoo.com

Today’s Date: 2-25-2020

Do you wish to make oral public testimony at this Hearing: Yes X No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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As one of the landowners of the project we are all for this project. Our ground was previously in OP
d The ground in shallow and wheat yields are poor. It is not worth farming
and we think a solar project would be a good option.
Name (mandatory)  CHUCK LITTLE
Mailing Address (mandatory)  17 WESTVIEW DRIVE
                                      HERMISTON, OREGON 97838
Phone Number (optional)  541-667-8898 Email Address (optional)
Today's Date: 2-25-2020
Do you wish to make oral public testimony at this Hearing:  Yes  No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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Written Testimony
(Please print legibly – Use the back for additional space if needed. Additional written comments may be attached to this card.)

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________________________________________________________________________
Oregon Department of Energy and
the Energy Facility Siting Council
Public Hearing on the Draft Proposed Order
for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory)  Jerry & Vickie Ashley

Mailing Address (mandatory)  90530 Bakeoven Rd.

                      Milwaukie, OR 97267

Phone Number (optional)  503-235-5252  Email Address (optional) VickieAshley37@yahoo.com

Today’s Date:  2/25/2020

Do you wish to make oral public testimony at this Hearing:  Yes  X  No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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Written Testimony
(Please print legibly – Use the back for additional space if needed. Additional written comments may be attached to this card.)

I fully support the project. Farming on this land is very marginal. With today's economy, the need for energy produced is greatly in demand.
Oregon Department of Energy and the Energy Facility Siting Council

Public Hearing on the Draft Proposed Order
for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory)  Michelle Slater

Mailing Address (mandatory)  5 Centerpointe Dr Suite 250
Lake Oswego, OR 97035

Phone Number (optional)  503-577-1446

Email Address (optional)

Today’s Date: 2-25-2020

Do you wish to make oral public testimony at this Hearing: Yes [X] No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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Written Testimony
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Oregon Department of Energy and the Energy Facility Siting Council

Public Hearing on the Draft Proposed Order for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory)  LARRY CHAMBERLIN
Mailing Address (mandatory) 2755 H ST BAKER CITY, OR 97814

Phone Number (optional) (541) 815-7714   Email Address (optional) LCHAMBERLIN@LOCAL.737.ORG

Today's Date: 2/25/20

Do you wish to make oral public testimony at this Hearing: Yes No

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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Written Testimony
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SEE ATTACHED NOTES. THANK YOU.

I'm in favor of this project. Renewable energy is the future. It will put people to work, at a live wage. That money comes back to our communities.
February 24, 2020

Sarah Esterson, Senior Siting Analyst
Oregon Department of Energy
550 Capital Street NE
Salem, OR 97301

*Re: Bakeoven Solar Project, Written comment submitted by LiUNA, Laborers Local 737*

**Bakeoven Solar Project - Public Hearing**

LiUNA Laborers’ Local 737 requests any Contractor or Subcontractor seeking to perform construction or maintenance services for the Bakeoven Solar Project, under a contract awarded by Wasco County, be susceptible to responsible contractor policy and language.

We feel it not only vital, but necessary for Wasco County to incorporate and implement the following responsible contract policy requirements;

1. **Apprenticeship Training:** Proof of participation in bona fide registered apprenticeship programs for all craft employees employed by the contractor / subcontractor to perform contract work.

2. **Health Insurance:** Proof of participation in a bona fide health insurance plan which covers all employees employed by the contractor / subcontractor to perform the contract work.

3. **Pension Plan:** Proof of participation in a bona fide pension plan which covers all craft employees employed by the contractor / subcontractor to perform the contract work.

The incorporation and implementation of responsible contractor language in the Bakeoven Solar Project, not only promotes best practices, efficient processes and procedures, but ensures safety standards and dignified employment, resulting in quality returns of investment in the project’s completion and for the community of Wasco county.

Sincerely,

LiUNA Laborers’ Local 737

Phone (541) 801-2209 | 17230 NE Sacramento Street, Suite 202 | Portland, OR 97230

www.Local737.org
I'm in favor of the Bakeover Solar Project.

The future is renewable energy and I believe this project is a move in the right direction. Rural Oregon construction workers will benefit from this job. I also believe higher wages and responsible contractor/subcontractor language (see other side)
should be Adopted to the project.

Thank you,

John Hanner - Laborer's Local 737
Oregon Department of Energy and the Energy Facility Siting Council
Public Hearing on the Draft Proposed Order for the Bakeoven Public Hearing
February 25, 2020 5:30 p.m.
Public Written or Oral Testimony Registration

Name (mandatory) Betty Odom

Mailing Address (mandatory) 55133 Juniper Flat Rd
Maupin, OR 97037

Phone Number (optional) 541-1993-2309 Email Address (optional) odombethy 43@yahoo.com

Today’s Date: 2-25-2020

Do you wish to make oral public testimony at this Hearing: Yes No ✓

Written comments can also be submitted today.

All written comments must be received by the deadline, close of the February 25, 2020 public hearing:

Sarah Esterson, Senior Analyst
Oregon Department of Energy
550 Capitol St. NE, 1st Floor
Salem, OR 97301
Email: sarah.esterson@oregon.gov
Fax: 503-373-7806

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Written Testimony
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Why is the maximum being limited to this project?

Much of the surrounding land is also level but even worse soil than this project’s soil.

Major transmission are located near or on my land depending which site I made contact in March 2019 following the first notice
of the project and was told no more was needed.
I asked for further contact and received no
additional contact from Avangard. What does it
take for others in this area to be considered?
My crooked land won't even grow weeds. The
land has been tilled for crops for decades with
less than 25 bushels to the acre because of
such poor soil.

What will this do to the wildlife? The fields
being proposed have deer, elk, antelope. Also,
will this affect wildlife migratory problems?
What will this do to our underground water?
What about birds?

Lots of questions that haven't been answered.