Oregon Public Utility Commission

SB 978

ACTIVELY ADAPTING TO THE CHANGING ELECTRICITY SECTOR

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CONTENTS

SB 978 – ACTIVELY ADAPTING TO THE CHANGING ELECTRICITY SECTOR

The PUC stands ready to use the powerful tools of economic regulation—traditional and evolving—to achieve the objectives that the Legislature prioritizes for Oregon's regulated electric utilities.

For more than a century, the Public Utility Commission of Oregon (PUC) has adapted to industry changes and new technologies—maximizing public benefits and protecting customers across the state who rely on essential utility services. By passing SB 978, the Legislature identified a moment of significant change in the electric industry and for the PUC.

SB 978 directed the PUC to use a public process to explore how investor-owned electric utilities are regulated in a rapidly changing industry and policy environment. The law asked the PUC to identify changes that could "accommodate developing industry trends and support new policy objectives without compromising affordable rates, safety and reliable service."

The PUC engaged participants in a dynamic and inclusive public process. By a wide margin, participants' top priorities were for the PUC to directly address climate change and equity. Participants also recognized the challenges and tradeoffs the regulatory system faces in responding to accelerating technology change and customer desires for new solutions to meet their environmental, resilience, and economic goals. Participants worked together—collaborating and challenging one another—to explore areas for action by the PUC and the Legislature.

Informed by this dialogue, the PUC offers a roadmap for actively adapting to the changing electric sector. This roadmap represents a dynamic strategy to:

- update and clarify PUC objectives and
- develop modern regulatory tools, market structures, and processes to achieve those objectives.

It is the strategy for change that the PUC believes will most effectively achieve legislative goals and produce the best overall outcomes for all customers of Oregon's regulated electric system.

Legislative Action

The PUC will collaborate with the Legislature and stakeholders to make progress on climate and equity—two issues that most SB 978 participants prioritized.

- **Climate Change**— Reducing greenhouse gas emissions is a high priority goal for the State of Oregon and the PUC's stakeholders, but the PUC lacks a clear mandate to address emissions except as an economic risk. The Legislature should take up this regulatory gap.
- **Affordability, Equity and Environmental Justice**—The Legislature should consider ways to improve equitable and affordable access to energy services. The PUC can and will take some steps without legislative action, but approaches used successfully elsewhere, such as rate discounts, may not be possible within the PUC's current authority.

The PUC's authority to regulate utilities is delegated from the Legislature. The PUC's legislative mandate is to use economic regulation to ensure that regulated utilities make safe and reliable electricity available to everyone in their service territories at reasonable, non-discriminatory rates. SB 978 participants reaffirmed that these goals remain central to the PUC's mission.

The PUC cannot require utilities to accomplish societal objectives that are outside the scope of utility regulation and that impose costs that the Legislature has not required utilities and their customers to bear.

The Legislature has directed the PUC to implement policies motivated by other societal objectives, such as the renewable portfolio standard, low-income bill assistance, direct access for large customers, and others. The PUC must implement these specific policies against the backdrop of its general legislative mandate, which does not expressly include reducing greenhouse gas emissions—from the electric sector or other sectors, such as transportation—or creating service classifications based on factors other than costs of service.

This report and the work of SB 978 participants (presented in Appendix E) offers a variety of approaches for the Legislature to consider if it wishes to include these or other emerging objectives in the PUC's mission. These objectives should complement the core economic regulatory objectives of safety, reliability, and affordability. The PUC is ready and willing to support this legislative process.

PUC Action

The PUC's strength is using unbiased, economic analysis and independent decision-making that balances trade-offs among competing priorities. In response to accelerating technology and industry change, the PUC will adapt its regulatory tools in two areas with wide-ranging impacts. The PUC also will deepen its engagement with regional actors and with stakeholders in its public process.

- **Retail Customer Options**—The PUC will enable customer and competitive options to be ***fully and accurately valued*** and, therefore, encouraged to expand in alignment with legislative goals and the overall strength and efficiency of the utility system.

One priority area is distribution system planning transparency, which can reveal where customer and competitive options can provide maximum value to all customers.

A goal of this effort will be to achieve more consistent pricing methodologies for distributed energy resources—including solar, storage, and demand side measures—in order to provide responsive pricing signals that keep pace with rapidly changing technology and supply options.

Throughout, the PUC will actively monitor new products, services, and markets, and encourage utilities to integrate service relationships with innovative third parties, including Energy Trust of Oregon.

- **Utility Incentive Alignment**—The PUC will launch a ***performance-based regulation*** process to align utility incentives with customer objectives. Proposals will be invited under the PUC's existing "alternative form of regulation" statute.

The long-standing economic incentives for utilities to invest significant capital in order to earn a return for investors and to realize earnings through sustained load growth have produced the highly reliable, low cost, centralized utility system that we enjoy today. The PUC recognizes that adjusting a utility earnings model that has worked well for utility investors and customers is a complex endeavor. It requires deliberation and careful design.

Exploring discrete areas of utility service where the PUC can allow utilities to earn a return on outcomes rather than on capital expenditures will reduce tensions with competitive providers and provide incentives for innovation while leading to the best results for utility customers.

- **Regional Market Development**— The PUC will participate with other states and agencies to ***promote regional market development***. This is a foundation for enabling efficient wholesale competition and regional resource diversity to lower costs and risks to customers.

The PUC does not recommend consideration of more fundamental changes to Oregon's wholesale or retail market structure at this time. An organized regional market is foundational to further evolution and is supported by a broad consensus of SB 978 participants.

- **Participation**— The PUC will implement a strategy for ***engagement and inclusion in PUC processes***, particularly from community based groups new to the PUC.

The PUC's SB 978 process benefited from a diverse range of perspectives, including participation by groups and individuals new to the PUC process. The PUC will carry these benefits forward beyond the SB 978 process, including by promoting discussion of new funding mechanisms for participation.

SB 978 Process

The innovative SB 978 public process exceeded its goals by engaging a wide range of participants, including many new stakeholders. Thoughtful, candid dialogue allowed them to:

- ***Educate each other*** and the Commission on their perceptions of the existing system and trends;
- ***Surface*** foundational ***assumptions*** about the electricity sector;
- ***Identify*** traditional and new public ***policy objectives***; and
- ***Reflect*** on whether ***new authorities, structures, and tools*** could help accomplish those policy objectives in today's environment.

INTRODUCTION

Since electricity was added to the Public Utility Commission of Oregon's (PUC or Commission) regulatory mandate in 1911, the electricity sector has experienced dramatic changes in the technology used to supply and manage electricity. Since the 1970s, there has been a growing movement to reduce the environmental impacts of the electricity system. More recently, there has been increased customer interest in having more electricity options and an emerging awareness of social equity as a policy objective. In the past two decades, the Legislature has responded to evolving technology trends and policy goals by passing laws to promote specific new tools and technologies, including customer choice and competition, energy efficiency, renewable energy, energy storage, and utility investment in electric vehicle infrastructure.

With SB 978 (2017), the Legislature asked the Commission to explore and examine the most recent changing dynamics of the regulated electric system in a more integrated and holistic manner. When authority for the Commission was first established through the Public Utility Law of 1911, the primary concern was to bring electricity service to all citizens with an emphasis on affordability and reliability. Now, with the expansion of electric service complete and the focus on transforming the system to achieve new objectives, SB 978 asked us whether changes to the regulated electric system and its incentives would help meet today's most important societal objectives.

The PUC aimed for innovation and new perspectives in the SB 978 public process. We used a third-party facilitator, the Rocky Mountain Institute, to design a dynamic engagement process and an outside advisor, the Regulatory Assistance Project, to assist in developing thought-provoking content. We enjoyed active participation by a wide range of stakeholders—both new to and experienced with the PUC—who challenged each other and collaborated throughout the process. Appendix A summarizes these groups' work. The mutual understanding and connections among participants achieved during the process, and the work that participants and the Commission will accomplish together moving forward, are an important outcome of the SB 978 process.

Informed by this dialogue, the PUC offers a roadmap for actively adapting to the changing electric sector. This roadmap represents a dynamic strategy to update and clarify PUC objectives and develop modern regulatory tools, market structures, and processes to achieve those objectives. It is the strategy for change that the PUC believes will most effectively achieve legislative goals and produce the best overall outcomes for all customers of Oregon's regulated electric system.

Our six priority areas for action are:

- **Climate Change**—Reducing greenhouse gas emissions is a high priority goal for the State of Oregon and the PUC's stakeholders, but the PUC lacks a clear mandate to address emissions except as an economic risk. The Legislature should take up this regulatory gap.
- **Affordability, Equity and Environmental Justice**—The Legislature should consider ways to improve equitable and affordable access to energy services. The PUC can and will take some steps without legislative action, but approaches used successfully elsewhere, such as rate discounts, may not be possible within the PUC's current authority.
- **Customer options**—The PUC will enable customer and competitive options to be ***fully and accurately valued*** and, therefore, encouraged to expand in alignment with legislative goals and the overall strength and efficiency of the utility system.
- **Utility incentive alignment**—The PUC will launch a ***performance-based regulation*** process to align utility incentives with customer objectives. Proposals will be invited under the PUC's existing "alternative form of regulation" statute.
- **Regional Market Development**—The PUC will participate with other states and agencies to ***promote regional market development***. This is a foundation for enabling efficient wholesale competition and regional resource diversity to lower costs and risks to customers.
- **Participation**—The PUC will implement a strategy for ***engagement and inclusion in PUC processes***, particularly from community-based groups new to the PUC.

These conclusions and recommendations, discussed in Section IV, represent a roadmap for a journey that is demonstrated in pending and planned Commission dockets and investigations. Before discussing our conclusions and recommendations, we summarize briefly the key features of Oregon's electric regulatory system in Section II, with a significantly expanded discussion in Appendix B. In Section III, we identify key technology and policy trends that provide context for our conclusions and recommendations. We conclude the report with a summary of our recommendations and next steps.

KEY FEATURES OF OREGON'S ELECTRIC REGULATORY SYSTEM

The electric regulatory system is complex. The SB 978 process exposed new participants to the system's physical structure, history, fundamental objectives, and basic mechanisms (a detailed summary of which can be found in Appendix B). Here, in a brief overview, we describe the fundamental foundations of Oregon's regulatory system and market structure.

The Regulatory Compact, Regulatory Objectives, and Ratemaking Mechanisms

The Regulatory Compact: Utilities are Accountable to Serve All and Entitled to Fair Compensation

As the electricity system developed and was recognized as an "essential service affected with the public interest," a single provider that was "vertically integrated" (meaning, it owned and operated all three elements of the electricity system: generation, transmission, and distribution) could expand the system to serve everyone at lower cost with greater efficiency and reliability than if multiple competing providers were providing the same service. For-profit utilities were allowed to operate as protected monopolies in defined geographic service areas (territories) in exchange for consenting to serve all customers at a price calculated to cover operating costs plus a reasonable return on the capital invested. This is known as the "regulatory compact."

The core elements of the regulatory compact remain in place in Oregon today. The utility has the obligation—and, for residential customers, the exclusive right—to serve anyone located within its service territory in a manner that is safe, reliable, and nondiscriminatory. In exchange, the utility is allowed the opportunity to collect the costs of providing that service, plus a fair return on investment, in rates set by the Commission. The Commission's fundamental responsibility is to regulate in the interest of utility customers, but to do so, the Commission must also ensure that rates are fair to the utility to satisfy its obligations to customers.

Traditional Regulatory Objectives: Safe and Reliable Service at Just and Reasonable Rates

The PUC has broad authority from the Legislature to regulate in the public interest in matters of utility rates, safety, and consumer protection. However, the Commission cannot take actions or require regulated utilities to take actions that fall outside the scope of its general statutory authority and jurisdiction, or its more specific authority granted by the Legislature to implement certain laws or policies that apply to regulated utilities. The Commission's core authority is to use economic regulation to ensure that utilities provide safe and reliable electric service to everyone in their service territories at reasonable, non-discriminatory rates.

The PUC also implements energy policies that are driven by additional legislative objectives. In 1999, the Legislature adopted SB 1149 (discussed below), which prioritized competition and customer options. New laws in the 2000s required investor-owned utilities to use—or allowed customers to choose—renewable energy resources and to phase out coal-fired generation.

These policies gave the PUC new responsibilities to implement specific directives, but did not provide a change to the Commission's general guiding objectives and legal authority. For example, although the Commission implements the Legislature's numerous clean energy policies motivated in part by climate change mitigation and other environmental goals, the Commission can only consider greenhouse gas emissions and other environmental factors as an economic risk factor in utility resource planning.[1]

Cost-of-Service Ratemaking in Oregon: Rates Reflect the Cost of Utility Service and are Applied Equally Within Broad Customer Classes

Through the traditional regulatory model, regulators use economic incentives in the ratemaking process to align utility performance with the broad regulatory objectives of safe and reliable service at just and reasonable rates. The Commission generally does so through cost-of-service regulation, but has adapted this traditional regulatory model in several ways. Appendix B contains a detailed review of Oregon's ratemaking mechanisms. Here, we briefly describe the most significant features and incentives within the traditional regulatory system, as well as previous actions that Oregon has taken to balance or mitigate those incentives:

- **Utility rates include the opportunity to recover reasonable operating costs and to earn a return on prudent capital investment (but not on operating costs)**

Rates for electric service are set by determining the annual "revenue requirement" necessary to provide service that includes: (1) the utility's reasonable operating costs; (2) paying the utility back for capital prudently invested; and (3) a Commission-established rate of return on prudent capital investments that provides the opportunity for utility shareholders to earn a fair return. Rates do not include a return on operating costs, which may motivate utilities to prefer capital-intensive solutions. This capital investment incentive has promoted achievement of a highly reliable electric system, but capital investments are not always the optimal way to address utility system needs.

Previous Action: Oregon has adopted mechanisms to balance this incentive, including scrutiny of the need for new investments and demand-side alternatives in integrated resource plans, as well as competitive bidding rules to level the playing field for solutions that do not involve capital investment by the utility.

1 *Re Dev. of Guidelines for the Treatment of External Envtl. Costs*, Docket No. UM 424, 1993 WL 388945 (Or. P.U.C. Aug. 10, 1993).

- **Maintaining customers and increasing customer sales help utilities cover system costs and remain profitable**

To set rates, the utility's total annual revenue requirement is spread across the expected amount of electricity sales within a rate structure for each customer class. Because fixed rates per kilowatt hour of electricity will be in place until the next rate case, utilities must address increased operating costs between rate cases by increasing electricity sales, increasing operational efficiency, or reducing quality of service. A motivation to increase electricity sales may create an economic disincentive to promote energy efficiency and distributed generation, which reduce utility electricity sales.

Previous Action: Oregon has adopted measures to counteract this disincentive, such as decoupling and creation of the Energy Trust of Oregon (Energy Trust) as a third-party to deliver energy efficiency savings.

- **After-the-fact review of utility investments lowers customer risk, affects utility risk tolerance**

Utility capital investments must be complete and serving customers before they can be included in customer rates. Thus, the Commission undertakes a "prudence review" of utility capital investment that happens after-the-fact in the general rate case in which rate recovery is sought. This promotes a low-risk system, in which the utility is motivated to invest in proven technologies with lower cost recovery risk and may be less inclined toward innovative technologies.

Previous Action: Integrated resource planning and specific legislative resource directives have been created to provide more regulatory certainty by offering opportunities for advance Commission guidance. These tools reduce the utility's risk of not recovering its costs for investing in new technologies through customer rates.

- **Rates are collected from broad customer classes without discrimination**

Rates for individual customer classes (e.g. residential, commercial, and industrial) are set based on the cost to serve classes of customers whose usage and cost profile to the utility system is similar. The Commission may not allow utilities to unduly discriminate or provide preferential treatment to customers of a certain class or within a customer class, but may create different classifications where there are distinguishing factors related primarily to the cost to serve those specific customers. Rates that are cost-based and uniform across customer classes protect customers generally from discrimination against, or preferential treatment for, individuals and sub-groups of customers.

As this overview suggests, a centralized system that socializes costs based on broad customer classes (also known as "service classifications") is at the foundation of the cost-of-service regulatory and ratemaking paradigm. The Commission determines a reasonable total revenue requirement that would allow the utility to fulfill its obligation to provide safe and reliable service and comply with all public policy requirements, plus potentially earn a shareholder return on capital investments that are serving customers. Then, the Commission sets rates to allow the utility to collect the established revenue requirement from utility customers.

Hybrid Market Structure, Vertically Integrated Utilities and Competitive Providers

Hybrid Retail Market Structure: Direct Market Access for Some Customers, Utility-Provided Choices for Others

Oregon has a hybrid retail market structure, meaning the basic vertically integrated monopoly structure remains in place for residential customers, but some commercial and industrial customers may bypass the utility and directly procure electricity from competitive suppliers. The Legislature adopted this hybrid structure in 1999 with the passage of SB 1149. It gave commercial and industrial customers "direct access" to third-party energy providers. Customers that switch to direct access must pay a Commission-established rate, inclusive of transition charges and credits, to reflect the impacts of their departure to the utility system.

Utilities offer customers choices other than full market access by way of energy efficiency incentives, demand response programs, renewable energy certificate purchasing, net metering, community solar, and voluntary renewable energy tariff programs. Most of these programs have been mandated by the Legislature and focused on clean energy policy goals, allowing customers to use distributed generation resources, like solar, to serve a portion or all of their electricity needs. Many of the programs offer access to third-party suppliers through a utility tariff or a third-party administrator like Energy Trust, with PUC oversight.

By contrast, some jurisdictions outside Oregon have "fully restructured" or "deregulated" retail markets. In those areas, utilities continue to own and operate the distribution grid, but customers choose their electricity providers and a regional transmission operator organizes those providers' access to electricity supply from the competitive wholesale market. (See graphic Appendix C). Because competitive suppliers are not rate-regulated, meeting policy objectives relies on market forces and effective market rules or other interventions.

Competitive Forces in Wholesale Markets: Policies to Promote Resource Diversity and Cost Discipline in Utility Procurement

Utilities must procure electricity to meet remaining customer needs not served by direct access, distributed generation, community solar, and other customer generation programs. To acquire the wholesale electricity supply needed to serve customers, utilities in Oregon can either own electric generating resources or purchase electricity from independent power producers through power purchase agreements. Two key policies have attempted to promote the participation of competitive providers in wholesale electricity supply.

The first is the federal Public Utility Regulatory Policies Act of 1978 (PURPA)[2] that requires utilities in regions without competitive wholesale markets to purchase electricity from qualifying facilities—primarily from smaller renewable energy projects—at prices set by the PUC to reflect the avoided cost of the electricity the utility would otherwise have to procure.

The second is competitive bidding. In Oregon, when utilities identify a need for large new generation resources to serve customers, the PUC requires utilities to consider offers from independent power producers. The purpose of this requirement is to introduce resource diversity and cost discipline to utility procurement, rather than requiring particular procurement outcomes.

Other states have chosen to change their wholesale industry structure, requiring electric utilities to procure all wholesale electricity through power purchase agreements and in some instances requiring their electric utilities to divest ownership of power plants. These states have concluded that wholesale electricity generation *(i.e.,* generating electricity to sell to a utility or other entity that serves end-use retail customers) is no longer a necessary or appropriate part of the regulated monopoly structure and that customers will benefit from requiring utilities to purchase all wholesale energy generation from independent power producers. This commonly occurs within organized wholesale markets where a central transmission operator organizes wholesale purchases and sales. In these states, utilities are still required to comply with regulatory requirements, such as renewable portfolio standards (RPSs), meaning that Commission oversight of a utility's generation procurement can still be used to meet policy objectives.

Transmission and Distribution: Maintaining Reliability and Organizing Access to the Grid

Reliable electric service requires expert management of a complex, interconnected grid. Electricity supply must be balanced with demand at all times. Utilities have the complicated and challenging task to ensure that transmission systems (large power flows across long distances) and distribution systems (networks reaching end-use customers) are safe and reliable.

In most regions of the United States, a centralized operator organizes transmission systems, ensuring reliability and managing purchases and sales of electricity by wholesale market participants. In the western United States, however, there is no centralized transmission operator. In the Northwest, Bonneville Power Administration owns and manages the vast majority of the regional transmission system, and each electric utility regulated by the PUC also controls transmission lines (or shares of transmission lines) and individually balances supply and demand and controls access by non-utility generation owners. However, all electric utilities regulated by the PUC have recently begun to participate in the California Independent System Operator (CAISO) Energy Imbalance Market (EIM), which has benefitted utility customers across the west with more efficient access to resources to meet a small portion of their moment-to-moment needs for balanced energy supply and demand.[3]

All utilities must own and manage safe and reliable distribution systems—the network of substations and smaller electric lines that connect end-use customers to the larger distribution and transmission grid. The distribution grid works in two ways. It delivers electricity from the larger transmission grid to customers, and also receives electricity from distributed energy resources (rooftop solar or other distributed generation). Though some distributed energy resources have existed on utility systems for many years, the complexity of managing a two-way flow of electricity on the distribution system increases as distributed resources expand.

2 PURPA requires utilities to purchase the electric output from qualifying facilities of a certain size. States develop PURPA implementation rules.

3 CAISO Gross System Benefits, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx, accessed Aug. 11, 2018.

CHANGING CONTEXT: TECHNOLOGY AND POLICY

SB 978 provided a list of technology trends and policy drivers for consideration in our public process. To capture this discussion, we highlight four themes that proved significant to participants and the PUC throughout the SB 978 process:

1. Societal interests in climate change, social equity, and participation
2. Rapid change in capabilities and costs of new technology
3. Balancing individual choices and collective system goals
4. Competition and market development

Discussion of these four contextual trends provides a foundation for Section IV, where we describe the tensions these trends create and our conclusions about the best ways for the regulatory system to adapt.[4]

Societal Interests in Climate Change, Social Equity and Participation

Two of the strongest themes for participants in the SB 978 process were not exclusively utility sector trends, but instead related to the roles of regulated utilities and the PUC in advancing broader societal interests in climate change mitigation, social equity, and inclusion of underrepresented communities. Participants identified actions the Commission could take within its current statutory authority to address these issues, but recognized that legislative action would be required to make other changes.

Climate Change and Environmental Impacts

Since the 1970s there has been an increased focus on the environmental impacts caused by energy use. Over the years, as environmental regulation has increased, the energy sector has adjusted by making physical changes to the system, the costs of which flow through to customer rates. Stakeholders both within and outside of the SB 978 process have emphasized the continued and pressing need to mitigate environmental impacts of the energy sector, specifically greenhouse gas emissions.

Many SB 978 process participants identified climate change as an imperative issue that must be addressed as quickly as possible. They emphasized the important and central role the electric sector should play in meeting the state's greenhouse gas emission goals, both by reducing the electric sector's carbon emissions and helping to reduce emissions from other carbon-intensive sectors.[5] In 2016, more than 26 percent of the state's greenhouse gas emissions were attributable to the electricity sector.[6]

In the SB 978 process, a group of participants indicated that in order to effectively decarbonize the energy system, Oregon must accomplish three overarching objectives: (1) maximize energy efficiency and conservation to reduce electricity and natural gas loads; (2) transition from fossil fuels to renewable energy sources; and (3) decarbonize the transportation sector and other carbon-intensive sectors and end-uses.[7] Participants in the SB 978 process made clear that reducing greenhouse gas emissions is a societal goal that should be integrated into legal requirements on the utilities and a role for the PUC. However, currently Oregon lacks legislative mandates to reduce greenhouse gas emissions, and the PUC does not have a clear mandate to apply its regulatory and ratemaking decisions toward these objectives.

How the state chooses to address greenhouse gas emission reductions will have a significant impact on the utilities the PUC regulates, ranging from what types of resources the utilities select to how they manage their greenhouse gas mitigation compliance requirements. Most stakeholders agreed that an economy-wide greenhouse gas policy is the most effective approach. Even if a greenhouse gas price or policy is mandated by the Legislature, some participants indicated there may need to be additional utility action taken to reduce emissions in other carbon-intensive sectors, such as the transportation sector, through electrification.

Social Equity and Participation

Social equity was identified by participants as something that should be a driver in PUC processes. Traditional cost-of-service regulation relies on customers to pay for the costs they cause the system, but stakeholders have indicated the PUC should focus on equitable, affordable outcomes for all customers, including low-income customers.

The U.S. Census (2011-2015) reports that the national average energy burden[8] for low-income households is 8.2 percent, which is three times higher than for non-low

4 We have also provided the Regulatory Assistance Project's paper, "Trends in Technology and Policy for Utility Regulation" as Appendix D for information on additional trends.

5 Oregon's greenhouse gas emission reduction goals are: 10 percent below 1990 levels by 2020 and 75 percent reduction below 1990 levels by 2050.

6 Department of Environmental Quality, "Oregon Greenhouse Gas Sector-based Inventory Data," https://www.oregon.gov/deq/aq/programs/Pages/GHG-Inventory.aspx, accessed July 24, 2018.

7 "Low Carbon Future Group Memo" to the Oregon PUC, May 31, 2018, Appendix E-1.

8 The U.S. Department of Energy defines energy burden as the percentage of household income that goes toward total energy costs including transportation, natural gas, and electricity.

income households.[9] To address the greater energy burden on low-income customers, some states have developed Percentage of Income Payment Programs (PIPP) or rate discount programs. Under a PIPP, rather than paying the retail rate of electricity, participants pay a percentage of their income or what has been deemed "affordable." Ohio[10] and Colorado[11] both have implemented PIPPs. In Washington[12] and California,[13] retail rate reduction or bill discount programs have been utilized to address energy burden. Under this program, qualifying participants only pay a portion of the retail rate. For instance, in Washington, customers receive a discount based on their income bracket.

Social equity concerns also extend to inclusion of underrepresented groups in decision making processes. Broader stakeholder representation in PUC processes is considered increasingly important as the opportunity for significant changes in the electric system have increased. In recent years, the number and diversity of stakeholders interested in participating in PUC processes has increased. These new groups and participants include more stakeholders representing a variety of new technology, competitive, and environmental interests, but some customer groups and communities remain underrepresented. In particular, community-based organizations representing people affected by PUC decisions have called for increased procedural inclusion. Participants indicated there should be a targeted approach to ensuring a balance of voices present in future PUC processes.

Rapid Change in Capabilities and Costs of New Technologies

Technology change in the electric utility industry is not new, but has become more rapid in the last ten years. Policy has accelerated some technology trends, particularly in renewable energy and storage, but other trends reflect broader market advances in digital and data technology. Because these technological advances hold promise of leading to a lower cost and lower emissions system, participants agree that the regulatory system and set of economic incentives should further adapt to integrate technology capabilities more quickly and take advantage of more opportunities. We have identified the technology trends and impacts most significant for Oregon's electric sector, and discuss those four key themes in the sections below, with Appendix D covering several others.

More renewables, low natural gas prices change energy market dynamics

Across the region, new renewable energy resources have been added to the foundation of hydroelectric generation in response to state policies, federal tax credits, and recently to falling prices that make wind and solar resources increasingly cost competitive with traditional fossil fuel-based resources. Ten percent of Portland General Electric's and PacifiCorp's 2014-2016 average electricity mix was met with wind and solar projects.[14] By 2040, the amount of variable energy resources on Oregon's electric system is anticipated to increase sharply such that 50 percent of energy needs are met by RPS-eligible renewable resources. As variable energy resources increase on the electric system, the need for flexible resources to integrate these resources and balance their output with load will grow.

Low natural gas prices interact with the addition of renewables to depress energy market prices. Customers benefit when utilities can avoid new generation expenses by purchasing from the market instead of building a generating resource. However, uncertainty about future energy market prices raises difficult questions about the relative value to customers of paying the fixed costs for existing and new energy resources versus relying on market purchases. Utility service that is more expensive than market purchases—due to fixed costs and other collective system policy requirements and objectives—increases customer desire to leave the utility to take service from competitive suppliers that can offer a higher proportion of market purchases at currently lower prices.

Further, a continued trend of low energy market prices may limit the amount of available cost-effective energy efficiency. Energy efficiency is a low-cost, low-impact, and broadly beneficial resource, but the supply of new efficiency measures and programs is limited by the cost utilities would otherwise incur through the purchase of electricity from the market or owned generation. Although Energy Trust acquired record levels of savings in 2017,[15] the forward outlook anticipates less available cost-effective resources. This is because some of the "low hanging fruit" measures have already been picked, the full environmental and health costs of traditional resources are not included in their market prices, and many new efficient technologies are not yet cost-competitive with low-cost, market resources. In order to decarbonize the electric sector in the most cost-effective manner, investments in energy

9 U.S. Department of Energy, State and Local Solution Center, "Low Income Community Energy Solutions," https://www.energy.gov/eere/slsc/low-income-community-energy-solutions, accessed Sept. 5, 2018.

10 LIHEAP Clearinghouse, Ohio Ratepayer Funded Programs, https://liheapch.acf.hhs.gov/dereg/states/ohsnapshot.htm, accessed Aug. 11, 2018.

11 LIHEAP Clearinghouse, Colorado Ratepayer Funded Programs, https://liheapch.acf.hhs.gov/dereg/states/cosnapshot.htm, accessed Aug. 11, 2018.

12 LIHEAP Clearinghouse, Washington Ratepayer Funded Programs, https://liheapch.acf.hhs.gov/dereg/states/wasnapshot.htm, accessed Aug. 11, 2018.

13 LIHEAP Clearinghouse, California Ratepayer Funded Programs, https://liheapch.acf.hhs.gov/dereg/states/casnapshot.htm, accessed Aug. 11, 2018.

14 Oregon Department of Energy, "Electricity Mix in Oregon 2014-2016," https://www.oregon.gov/energy/energy-oregon/Pages/Electricity-Mix-in-Oregon.aspx, accessed July 10, 2018.

15 Energy Trust of Oregon, "2017 Annual Report: Innovating for the Future," https://www.energytrust.org/annualreport2017, accessed Aug. 11, 2018.

efficiency will need to remain as one of the cornerstone electric system resource strategies. Continued investments in energy efficiency will moderate the risks and costs of renewable energy investments and provide flexibility in resource planning for the load growth we anticipate electric vehicles will bring.

Rapid technology and market changes challenge technology-specific policy mandates, resource planning, price setting

In today's environment, changes in market conditions, technology capabilities, and costs move faster than policy and regulatory processes. This creates a challenge for technology-specific policy mandates, resource planning, and accurate price setting.

Legislative action to mandate specific technologies has been successful in bringing down technology costs and allowing utilities to gain experience with new resources. However, rapid technology change increasingly favors policies that define a desired system outcome that could be met by a number of technologies that compete to achieve the desired outcome most efficiently or at the lowest cost.

For resource planning, technology cost inputs that are fixed at the beginning of an integrated resource plan (IRP) process may change significantly over the period of its development and review. By the time a utility identifies a resource need and issues a request for proposal, new technologies may be capable and cost-competitive but were not evaluated in the utility's IRP.

IRPs have been the Commission's foundation for setting "avoided cost" prices paid to renewable energy qualifying facilities. In an environment of rapid cost change, avoided costs derived from IRPs have been out of alignment with contemporaneous market costs, leading to significant frustrations for utilities, renewable energy developers, and the Commission regarding implementation of PURPA.

In this environment, some of the Commission's planning and regulatory processes need to move more quickly to remain responsive to market changes. Processes should move more quickly where utility customers will benefit from access to falling technology costs and advancing capabilities. For example, the Commission has already signaled its intention to improve the responsiveness of its PURPA implementation practices. For other processes, moving at a deliberate pace is important to protect customers and allow for balancing of significant competing interests. The PUC must actively balance between the risks of moving too slowly and those associated with responding too quickly.

Concerns about customer commitment to long-term investments and new technologies in a changing landscape

New utility-owned electric generating resources have significant, long-term impacts on customers. The Commission has been very deliberate in looking at the need and cost of a new resource, and the resource's lifetime benefit to utility customers when deciding whether to include that investment in customer rates. While uncertainty is always present, the rapid pace of technology change poses new challenges.

With rapid technology change, it is more likely that a commitment to an investment now could prove to be less advantageous if a new technology proves to be less effective than expected, a future new technology is superior in cost and performance, or market conditions dramatically change the value of the resource to the utility system. One regulatory response to the desire to maintain a low-risk, low-cost utility system is to limit customer commitments to new resources and to maintain optionality. On the other hand, customers may benefit from utilities exploring new technologies and taking early action to secure low-cost opportunities, but deliberative regulatory processes to balance important competing interests may impede this.

Electric vehicles (EVs) provide an example of both challenges. Uncertainty about the pace of EV adoption creates uncertainty about the long-term context for evaluating the need for new generating resources; rather than the current trend of slow to flat growth in electricity load, future electric load may grow significantly as a result of EVs. Conversely, utilities may seek to invest in EV infrastructure, but investments move slowly because the PUC requires robust pilot program designs and evaluation plans vetted through highly-participatory stakeholder proceedings. This is done to ensure utility customers will see system benefits from EV-related investments, given that customers will pay for them in their electricity rates, and to reasonably protect against undesirable impacts of utility participation on competitive market development. In some limited and well-defined instances, the Commission may need to consider new processes that move more quickly to capture benefits for customers.

Distribution system resources and management technologies require attention

Although penetration of distributed energy resources remains relatively low in Oregon (about one percent of customer load), costs continue to decline and customer interest and utilization is growing. More and more customer-sited energy storage projects are added to the grid each year by early adopters and critical facilities or industries driven by resiliency goals and a desire to pair storage with onsite solar resources.

Direct load control programs have potential to become firm flexible resources that utility systems will need in order to integrate the growing variable energy resources in the future. These technologies hold the promise of greater system efficiency, reliability, and other benefits, but also require substantial cost for planning and implementing these technologies throughout utility systems.

Technology advances in controls, sensors, communications, and automation equipment have the potential to add greater system awareness and real-time control capabilities for utility system operators. As interest and investment in distributed generation increases, additional location-specific data can be captured and analyzed to identify optimal locations to site new generation or storage resources. It can also be used to identify those areas where additional system upgrades are necessary prior to adding generation resources.

The rapid advancement and deployment of the digitalization of the grid is raising regulatory concerns of transparency in utility distribution system planning, investment, and asymmetry of knowledge in this area between utilities and the PUC. Also, the proliferation of digital controls and system data, including customer data, raises concerns about cybersecurity and data ownership, access, and confidentiality.

Balancing Customers' Individual Choices and Collective Goals

New technologies have led to new providers and new options for utility customers. As technology has evolved, state policies have consistently directed the PUC to give customers more options for energy services. With an increasing number of programs and options that allow customers to either leave the utility system and use a competitive provider of electricity supply (direct access) or to select specific resource and rate options within the utility system (net metering, renewable energy purchasing, community solar, voluntary renewable energy tariffs), and desire for customer choice likely to continue increasing, three key trends arise.

Managing customer choice to align with policy and regulatory objectives

Technology advances provide electric system customers with increased choices around how they supply their electricity needs. From low-cost rooftop solar to the availability of at-home energy storage systems, customers have more choices now than ever before—and this technology trend will continue. Oregon legislative policy has tracked the technology trends and mandated that customers be offered more choices, relying on the PUC to ensure choices are provided in a way that balances the goals of the program, the interests of the individual customer, and the goals of the collective utility system upon which non-participating customers rely.

Customer choice programs tend to be motivated by particular policy or regulatory goals, rather than purely by a desire to maximize customer independence. Some customer choice programs, such as community solar, are driven primarily by environmental policy goals (but may have secondary objectives around community well-being and economic development). Other types, such as direct access, are partially understood to be driven by economics for end use customers. Though some state policies apply to direct access electricity service suppliers (like renewable portfolio standards, though on different terms than regulated utilities), the Commission has limited regulatory authority and oversight over competitive suppliers.

Some states have concluded that full access to customer choice is the best approach, allowing customers to choose from various energy providers to fulfill a number of service needs and desires from cost control to environmental content. Utilities in Oregon and other states have sought to expand their ability to offer differentiated resource content to individual customers through evolving voluntary renewable energy tariffs.

Other states have devised options for allowing groups of customers to secure energy supply that satisfies their preferences while maintaining the benefits of aggregating load and advantages of centralized utility services. Community Choice Aggregation (CCA) allows a local government agency to purchase energy on behalf of customers in that local jurisdiction. CCAs exist in several states including California, Illinois, Ohio, Massachusetts, New Jersey, New York, and Rhode Island. In some states, CCAs can own and operate generation, however, in most states CCAs contract for generation.[16] In most cases, utilities retain their role in providing distribution, transmission, billing, and customer service to communities that have opted for a CCA.

While California's retail energy prices differ significantly from Oregon's,[17] California's experience with CCAs is instructive. With unprecedented growth in its Community Choice Aggregation program, the California Public Utilities Commission (CPUC) has estimated that by 2025 to 2030,[18] Pacific Gas and Electric, a large California utility, may only serve half of the load in its service territory. As this load departs, questions are being raised about how to insulate the remaining utility customers from having to bear all the costs associated with investments that were made on behalf of all customers and also finance the system's projected future obligations. The CPUC is actively managing issues related to CCAs and other customer choice options, including evaluating how increased customer choice impacts the state's ability to achieve its policy objectives of affordability, decarbonization, and reliability.[19]

16 Local Energy Aggregation Network, "What is a CCA?", http://www.leanenergyus.org/what-is-cca/, accessed Sept. 5, 2018.

17 In July 2018, the Energy Information Agency reported the average residential retail rate in Oregon was 11.02 cents per kilowatt hour, while California's average retail rate was 19.90 cents per kilowatt hour. For more information visit: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

18 California Public Utilities Commission, Community Choice Aggregation En Banc Presentation, Feb. 1, 2017, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Costs_and_Rates/CCA_and_Direct_Access/FinalStaffEnBancPresentation2.1.17.pptx, accessed June 18, 2018.

19 California Public Utilities Commission, California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market, August 2018. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf

Quantifying the costs and benefits of customer-owned generation and market access to the utility system

Depending on how customer choices are designed and offered, they can support or detract from general policy and regulatory objectives. Generally speaking, increasing distributed generation and other off-system choices lead to fewer customers and electricity sales from which system costs can be allocated and recovered. Transition charges paid by customers leaving the utility system must be designed to avoid harm to customers that remain with the utility. Likewise, payments for customer-owned generation must be in line with policy goals and economic value to the system.

To ensure that customer options support overall system goals, the value to the utility system of new customer options must be identifiable and customer payments must be aligned with that value. The growth of customer interest in distributed generation and energy storage, combined with lack of transparency into utility distribution system planning, challenges the PUC's ability to understand the real value of and accurately price customer-side investments. Being able to provide accurate, time-sensitive pricing on locational and other system benefits of customer generation would help the PUC value distributed resources more accurately and avoid the poor pricing signals that may increasingly create a mismatch in expectations between customers, utilities, and the PUC. Customers and third parties expect the new technologies they bring to the grid will provide net system benefits, yet the quantification of these benefits remains unclear or provisional as utilities adapt their systems to take maximum advantage of distributed resources.

Increasing the granularity and accuracy with which the value of customer generation to the system can be quantified is an important and necessary step. It can help incent customer generation to locate in places that provide the highest possible value to the system and ensure that payments for customer generation do not impose significantly increased costs on the collective utility system as penetration of distributed resources grows. Without an organized market to help quantify benefits, the process must continue to evolve through regulatory analysis and price setting.

Monitoring markets to determine appropriate role for utility and/or third-party providers

Surrounding customer choice is the question of what mix of options from the incumbent electric utility and third-party providers is most appealing for customers and best adapted to other system and policy objectives. Depending on the program design, the PUC may have less regulatory oversight of non-utility providers. It is unclear whether customers have an overall preference for utility or non-utility providers, though advantages may emerge for particular new electricity services as markets develop and the impact of utility participation is evaluated.

Wholesale Competition and Market Development

New technologies provide increasing opportunities for third parties to provide elements of electricity service, and competitive pressure to provide wholesale supply to utilities is intense. The PUC's competitive bidding guidelines are intended to level the playing field for competitive wholesale suppliers of electricity generation, in order to increase resource diversity and impose cost-discipline as a means to reach the least-cost, least-risk outcome for utility customers. However, some stakeholders claim that the competitive bidding process does not do enough to capture the differences in costs, benefits, and risks between utility-owned resources and power purchase agreements. Recent utility request for proposals (RFPs) for new large generating resources renewed stakeholder concerns that the utilities have an inherent, unmitigated incentive to own and rate-base large investments. Some stakeholders regard the utility capital investment incentive as simply too strong for competitive bidding processes to effectively mitigate, but others believe that competitive bidding—even when it results in utility-owned generation—has produced least-cost, least-risk results for customers.

Access to transmission has complicated recent competitive bidding processes, with significant controversy about whether utility access to transmission supported by customer rates gives utility projects an unfair competitive advantage and limits options for customer access to a broad pool of diverse resources. Participants in the SB 978 process indicated that, among other potential benefits, the presence of an Independent System Operator (ISO) or a Regional Transmission Organization (RTO) would minimize this perceived barrier to competition by opening up a more transparent, organized market for access to transmission resources.

WHAT COMES NEXT? TENSIONS, SOLUTIONS AND NEXT STEPS

Technology has evolved significantly in the last 30 years and the pace of change will only increase in the energy and transportation sectors. This crucial reality is a backdrop for our recommendations. Our recommendations are designed to allow the PUC and stakeholders to thoughtfully and actively adapt to a range of possible futures, balancing emerging risks against emerging opportunities to deliver on our regulatory mandate and implement required legislative policy goals.

The SB 978 process has confirmed the continued importance of the guiding objectives that underlie the core directives in the Commission's enabling statutes: safety and reliability, just and reasonable rates, and a utility's obligation to offer service to all customers in its service territory (non-discrimination). This process has prompted reflection on how the Commission defines those guiding objectives today and whether and how the Commission should incorporate new objectives for the electric system and new tools and structures to achieve those objectives.

Our conclusions and recommendations fall in six categories:

1. Climate Change and Greenhouse Gas Mitigation
2. Affordability, Equity, and Environmental Justice
3. Retail Customer Options
4. Utility Incentive Alignment
5. Regional Market Development
6. Participation

Below we discuss in detail the tensions that lead to each of our conclusions and recommendations.

Climate Change and Greenhouse Gas Mitigation

Commission's legal authority to consider greenhouse gas emissions

The Commission's statutes require regulation of the cost of providing energy to consumers, rather than the environmental consequences of providing energy to consumers. Today, the state's greenhouse gas emission reduction goals are not requirements that utilities must meet when considering resource acquisition decisions. The Commission's current statutory authority does not allow it to impose on the utility, directly or indirectly, environmental costs that the utility is not otherwise legally required to bear.[20] However, the Commission may consider the cost risk that environmental regulations may be imposed in the future in the IRPs of the utilities it regulates.

Because of this legal interpretation, the Commission's decarbonization role is focused on two areas:

- The Commission implements programs, policies, and administrative rules resulting from legislative requirements which regulated utilities must satisfy (*i.e.*, renewable portfolio standards, transportation electrification), using the criteria provided by the Legislature. The Commission uses safety, reliability, and just and reasonable rates—not greenhouse gas reduction—as its guiding principles for implementation.
- The Commission requires utilities to consider the cost of future potential regulation of greenhouse gas emissions as an economic risk factor in its integrated utility resource planning process,[21] but cannot require utilities to base resource planning decisions explicitly on achieving greenhouse gas emission reductions.

Climate Policy Perspectives

A broad range of SB 978 participants recommended that the Legislature establish greenhouse gas emission reductions as an additional guiding objective for the regulated electric sector and the Commission, though views differed as to what specific action the Legislature take in order to integrate this policy objective. There was a great deal of convergence amongst participants that climate change is an imperative issue, which should be dealt with as quickly as possible. A critical mass of participants pointed to a cap on greenhouse gas emissions as an effective way to mitigate climate change and establish a role for the PUC in the area of climate change.

Some participants felt that the Legislature should redefine the Commission's authority to make greenhouse gas mitigation a guiding principle, along with safety, reliability, and just and reasonable rates. Others recommended new authority for the PUC and new obligations for the regulated electric sector only as part of an economy-wide carbon policy, which would fairly distribute costs to all market participants and avoid diluting the Commission's economic regulatory role and placing the Commission in the position of setting the pace and depth of emission reductions.

While all participants emphasized the importance of accounting for the external costs associated with greenhouse gas emissions within the electric sector, some also pointed out that there could be more efficient and accelerated achievement of the state's emission goals. That is, if the electric utilities worked to reduce

20 *Re Dev. of Guidelines for the Treatment of External Envtl. Costs*, Docket No. UM 424, 1993 WL 388945 (Or. P.U.C. Aug. 10, 1993).

21 Under its current decision-making approach, the Commission uses a least-cost, least-risk framework. This means the Commission balances the risks presented by proposals with the total cost to ratepayers. Environmental costs which are not currently regulated or likely to be regulated in the future by state, federal government or local jurisdictions are not accounted for in this balance test, nor can they be directly imposed on utilities.

emissions outside of the electric sector through beneficial electrification of other fuel uses, such as electric vehicles and other forms of electrified transportation. Because the greenhouse gas emissions associated with charging an electric vehicle are significantly less than those associated with gas-fired engines, stakeholders expressed it may be beneficial to have the electric utilities participate more significantly in advancing the adoption of transportation electrification.

Absent a directive from the Legislature to include greenhouse gas reductions from other economic sectors in rates, when the PUC considers implementation of, for example, large-scale electric vehicle programs that require substantial amounts of utility cost to be recovered from customers, it must determine, among other things, that any infrastructure investment is prudent. Short of this, limited pilots can allow utilities to test whether a new and emerging program that might not presently be cost-effective from an electric system perspective could produce a benefit to customers in the future. These pilots have been limited in scope and generally have not included investment in actions outside of providing traditional electricity service unless authorized by statute *(i.e.*, SB 1547's authorization for approval of transportation electrification programs).

▶ **Next Steps**

Action on climate change emerged as one of the most critical issues in the SB 978 process. Participants generally agreed that the state should take action on mitigating climate change and that the electric sector has a key role to play in decarbonization.

Legislative direction and authority is needed before the Commission can require electric utilities to take new actions to reduce greenhouse gas emissions and recover increased costs of doing so from utility customers. The Commission is ready to work with the Legislature and stakeholders toward an appropriate role that is consistent with our primary function as an economic regulatory agency.

Defining a specific requirement for greenhouse gas reduction would be helpful. If the Legislature defines a specific requirement, such as a percentage of emission reductions for electric utilities in the context of a broader greenhouse gas emission policy, the Commission can oversee the development of the least-cost, least-risk method for the utility and its customers to achieve that outcome. Further, if the Legislature would like the electric sector to further reduce emissions in other sectors, such as the transportation sector, then legislative action will need to define the Commission's authority to do so—for instance, by creating a program which would incentivize the utilities to implement beneficial electrification of other fuels.

Affordability, Equity, and Environmental Justice

The regulated electricity system was designed to provide universal service for customers at rates that reflect the cost to serve them, without regard for customer circumstances unrelated to the cost of providing electricity service, such as ability to pay. Since that time, however, the Legislature has designed a small number of programs to address the needs of low-income customers, including crisis energy bill assistance and weatherization programs.

One of the top issues raised by participants in the SB 978 process was whether or not more measures should be taken to increase the affordability of electricity for low-income customers and how social equity and environmental justice are integrated into the Commission's decision making practices. The Commission is already active in these areas, but concludes that further Commission and legislative action is important.

Affordability and Equity

In the SB 978 process, participants and the Commission used the term "affordability" to address a variety of concepts. For clarity, we identify three distinct ways the Commission understands the concept of affordability to have been used in relation to the regulatory system during the SB 978 public process.

Customers and stakeholders generally regard affordable electricity as a core traditional objective for Commission regulation. In fact, the Commission's legal mandate is to set "just and reasonable" rates that reflect utility operating costs and the opportunity for a fair return on capital investments. The Commission has many mechanisms (IRP, RFP, prudence review) to ensure that utilities use a least-cost, least-risk approach to operating and investing in the system, and promotes other mechanisms (like energy efficiency incentives) to help customers reduce their electricity bills. The Commission's approach to regulation may seek to produce low rates and bills, but the Commission's core legal mandate is to set rates that are "just and reasonable," not to make sure rates remain at a certain level or have an equal affordability impact on all customers.

The second way the concept of affordability has been used in the SB 978 process is to assess the overall costs of the utility system, and the resulting customer rates and bills according to broad economic indicators and measures of affordability. During the SB 978 process, we reviewed the rates of Oregon's regulated electric companies in relation to national statistics for utility rates and the rates compared with the consumer price index as a way of considering whether the system is affordable across broad classes of customers. Affordability, in this sense, could be a desired outcome that is the foundation of a target or metric for performance-based ratemaking (discussed below).

Third, even if rates can be considered affordable relative to broad economic indicators and for most members of a customer class, some SB 978 participants concluded that Oregon electric rates are not affordable because they continue to impose a significant burden for low-income customers or other, more segmented customer groups. These participants presented perspectives about affordability and a need to adjust rates in light of the greater energy burden on low-income customers (See Appendix E-4). Participants argued that there should be a more nuanced definition of affordability and universal access that reflects the circumstances of narrower customer segments.

Environmental Justice

During the SB 978 process, some participants asked the PUC to consider social equity and environmental justice impacts within its decision making. In 2007, the Legislature passed SB 420 which requires fourteen state agencies, including the PUC, to consider the effects of their actions, when those actions impact environmental justice issues, by ensuring that all voices are heard, especially those that have been historically underrepresented and disproportionality affected by environmental decisions.

The Environmental Justice Task Force has defined "environmental justice issues" as "equal protection from environmental and health hazards, and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality, and play." The PUC understands the importance of this directive and has worked to improve the accessibility of public participation in its dockets where environmental justice issues may be implicated, for example, in its review of petitions for a certificate of public convenience and necessity to construct overhead transmission lines. In these dockets, the PUC has solicited extensive comments from the public and individuals living in the potentially affected communities at public meetings and hearings, and in particular instances, traveled offsite to hold public comment hearings within the affected communities.

However, SB 420 did not amend the PUC's enabling statutes that provide its authority with regard to setting just and reasonable rates or other statutes that provide standards for approval of applications by utilities. Thus, the PUC's focus has been on reducing barriers to public participation to ensure that all voices are heard in the decision-making process as SB 420 directed. However, improvements can be made to provide a better understanding of the impacts on environmental justice communities if and when those decisions come before the Commission, and to more actively solicit participation from groups not traditionally active in PUC proceedings.

▶ Next Steps

As we write this report, the Governor's Carbon Policy Office has convened a Low Income Utility Program Working Group to better understand if gaps exist between our current energy assistance programs required by the Legislature and the need experienced by low-income Oregonians today. The PUC is committed to continuing to assist the Low Income Utility Program Working Group to further understand energy burden impacts to low-income Oregonians and explore possible solutions. The work group is expected to provide recommendations to the Governor's Carbon Policy Office in December 2018.

In the past, when programs that provide assistance to low-income customers through weatherization services or bill pay assistance have been implemented, specific legislation has required the PUC to do so. While the PUC has been able to incorporate social equity and energy burden impacts into our work based on specific direction from the Legislature, our ability to further address energy burden concerns is limited given our statutory prohibitions against discrimination between customers (and corresponding prohibitions on preferential treatment between customers) based on factors other than cost-of-service or service characteristics, which are used to create separate classifications of service that pay different rates.

Direction from the Legislature would allow the Commission to prioritize how to integrate social equity and differential energy burdens into rate design and the Commission decision-making process more generally. The Legislature may be prepared to conclude that the Commission should be given express authority to establish a separate, low-income rate to address the energy burden of Oregon's low-income ratepayers. For example, this could be in the form of a bill discount, a percentage of income payment program, or other approach. However, the Commission would need express authority with detailed criteria to create a low-income rate for customers while keeping rates just and reasonable for other customers. The Commission supports exploration of ways to mitigate the energy burden of low-income Oregonians, whether that is through increased funding for weatherization programs or other mechanisms, and may recommend a more specific approach in this area after considering the outcomes of the Low Income Utility Program Working Group. One specific complement to any such approach that we recommend, and discuss further below, is legislative action to create additional intervenor funding for community-based organizations or funding for a low-income and environmental justice advocate.

There are some actions the Commission can take to address low-income energy burden and environmental justice without specific legislative direction.

- The Commission can explore opportunities to address energy burden that are consistent with our existing authority to create differentiated service classifications. For example, some have recommended that the Commission consider a separate rate class for multifamily housing, where some costs for the utility to provide electric service could be lower.
- The Commission will develop training for our staff and host a training once per year to familiarize and sensitize staff to topics related to social equity, access, and environmental justice. The Commission will engage external resources to develop this training.
- The Commission will also develop a process by which we will integrate an environmental justice impact analysis into rulemaking processes where applicable. This will raise stakeholder and Commission

awareness of the impacts of decisions that may affect environmental justice communities. The Commission will consider expanding the environmental justice impact analysis to other proceedings if it proves an effective tool to accomplish the goals of stakeholders and the Commission.

- The Commission will continue its role on the Environmental Justice Task Force, reporting information about the work it does to integrate equity and environmental justice within the agency's processes.

Retail Customer Options

The Commission discusses retail customer options here broadly, referring to any utility customer's ability to choose any product, service, program, or rate option that is outside the general, standard cost of service rate, whether offered by utilities or through third-party providers, which may include competitive firms or the Energy Trust.

Technology will continue to enable many new options, and the Legislature and the Commission will be presented with customer preferences to participate in new options through a wide range of regulatory vehicles. One vehicle is increasing customer access to competitive suppliers, through retail restructuring or expanded direct access. Another vehicle is utility-offered programs where customers can differentiate their electricity consumption or participate in supplying generation and grid services to themselves, their neighbors (through peer-to-peer transactions), and to the broader utility system. These may include utility green tariffs, community choice aggregation, energy efficiency, customer and community distributed generation (including solar and/or storage), and customer microgrids. Still another vehicle for customer options is through time-varying rate designs and expanded demand response programs.

Tradeoffs and tensions with increasing customer options

In the SB 978 process, participants raised the importance of increased access to options for customers at the retail level. These choices were described in a wide variety of ways, including access to more renewable energy, energy use reduction and management opportunities, aggregation of load, and self-generation. Participants also discussed options to purchase energy from an entity other than their utility, and more specifically, to purchase the output from a defined generation facility directly or through their utility.

Participants often asserted that customer choice would enable the state to meet its goals more quickly. For example, if customers had a choice about what resources made up their energy mix, the state would more quickly meet goals related to greenhouse gas emissions reduction. Access to greater customer choice could also help local municipalities and jurisdictions meet their climate and energy goals. For example, in 2017, Multnomah County and the City of Portland announced goals that all of their electricity should come from renewables by 2035.[22] Participants recognized, however, that customer choice programs are not always designed to achieve the asserted policy goals and that additional mechanisms to regulate choices and market providers would be necessary to ensure that customer choice aligns with the goals participants assert.

In addition, to achieve other current or emerging objectives, such as affordability and equity, customer choice programs must be designed intentionally to meet a customer's goals to go more quickly or farther than the overall system without adding significant unwarranted costs to non-participants. Customer options can benefit the system if they are designed to incent customer actions that support utility system goals and are priced accurately to meet system objectives.

Some participants asserted that customers would benefit from further opening Oregon's retail market structure to competition by allowing all customers the ability to choose an energy supplier other than their current utility. Although the time and scope of the SB 978 process did not allow us to investigate these claims, we did observe two themes that lead us to recommend against further exploration of retail restructuring at this time. The first is that the state does not have an organized market which would provide a critical backbone for increased competition. The second is that outcomes on cost, reliability, and customer choices from restructured markets in other states have been mixed. Moreover, it is more difficult to assure meeting the full suite of public policy goals and desired system outcomes in a competitive retail environment than in a regulated market structure. It is possible to create mechanisms and overlays to meet those public policy goals, but each outcome requires additional interventions that are less critical within Oregon's hybrid retail market structure. Some participants posited CCAs as a middle ground, though the PUC observes that the need for similar mechanisms and overlays would exist to ensure that policy objectives are met.

▶ Next Steps

The Commission observes that options for retail customers, both within and outside of the utility framework, should be understood and used as tools to achieve policy goals and objectives for the regulated utility system as well as for individual or aggregated groups of customers (such as local municipalities and jurisdictions). Customer choice should be designed to enable customers to achieve desired outcomes that are consistent with state policies and that help the collective utility system achieve its goals and objectives, including fairness to other customers.

In our role regulating system rates for all utility customers, we must balance a wide variety of customer desires—from those interested in having more energy choices to those who just want the lights to turn on. Yet technology options for meeting individual customer goals will continue to

22 The Oregonian, https://www.oregonlive.com/portland/index.ssf/2017/06/portland_multnomah_county_set.html, accessed June 15, 2018.

expand, as will new opportunities to leverage customer interests to benefit the overall system. Therefore, it is critical that the PUC accelerate its efforts to better understand how individual choices can be designed to positively impact the overall system.

Currently, we are working to better understand and quantify how choices available to customers now and in the future impact the performance of the utility system as a whole, including the rates of customers who remain on standard service. Multiple pending and planned investigations span two categories of customer options: those where customers and other non-utility owners are providing generation to the grid, as well as customer rate design options to support the grid by modifying their energy usage. They include, among others:

- Resource value of solar investigation (RVOS), focused on solar photovoltaic installations including community solar;
- Upcoming investigation of the Commission's approach to paying PURPA qualifying facilities [23] for avoided costs to the utility system;
- Continued refinement of methodologies for valuing energy storage use cases, and monitoring utility storage pilots—including customer microgrids;
- Examination of energy efficiency avoided costs and cost-effectiveness methodologies;
- Review of utility demand response and time-of-use rate pilot programs.

We list these activities to demonstrate the active role the Commission and its stakeholders are already taking to better enable access to customer choice. Through these processes we are ensuring that our programs and rate designs are appropriately compensating participating customers while ensuring that the system remains strong enough to continue to offer high-quality, fairly priced service to customers remaining within the default cost-of-service rate structures. (Some of which may themselves need to change over time to influence all customers toward efficient usage.)

Further, in PGE and PacifiCorp's recent IRPs, the Commission acknowledged a staff recommendation to open an investigation into distribution system planning. Over the coming year, the Commission anticipates this investigation will focus on increasing transparency and stakeholder engagement in grid modernization efforts necessary to evaluate utility investments through distribution system planning.

Coupled with ongoing grid modernization of utility systems and improved data collection and analytics, the ultimate goal of these discrete investigations is to develop an overall more accurate, granular approach to valuing system costs and benefits that inform fair pricing of customer options. The ability to accurately price products will lead to overall improved system efficiencies that benefit all customers.

23 Renewable and/or combined heat and power projects up to 80 megawatts.

Utility Incentive Alignment

One key finding of the SB 978 process is that strong stakeholder support exists to more clearly understand whether evolving regulatory tools can allow us to improve alignment between utility incentives and desired policy and customer outcomes.

Rationale for exploring new regulatory approaches

Our review of current trends such as the falling cost of renewable energy, the speed of technological innovation, and increased availability of customer options, brings into question the sustainability of the current incentives for utility earnings, specifically the throughput incentive and the return on capital investments. The throughput incentive exists because utilities earn revenue on a per kilowatt hour basis, creating an incentive for the utility to sell more kilowatt hours and therefore disincentivizing reduced energy sales. The capital investment incentive exists because utility rates provide an opportunity for the utility to earn a rate of return on capital expenditures in infrastructure.

In the current construct, the system rewards utilities for load growth and asset-based solutions to customer needs. Therefore, failing to address whether these incentives can be aligned in ways that benefit both utilities and customers allows persistent tensions to grow between stakeholders concerned about the capital investment incentive's impact on least-cost utility procurement. For example, stakeholders have raised a concern around continued utility investment in capital expenditures when access to capital is available to third-parties to develop projects that result in a reduced need for utility ownership of generation. Demand-side and distributed options, which might be less expensive than utility-scale investments, are also disadvantaged in a regulatory system that rewards both utility capital investments and higher electricity sales. Addressing incentive alignment creates opportunities to reward utilities for outcomes that benefit customers, such as managing peak load growth, rather than only for building infrastructure to meet growing peak loads.

Oregon is not alone in identifying a new opportunity for alignment between existing incentives and evolving system values and conditions. Interest in performance-based regulation is taking hold among stakeholders, utilities, and regulators nationwide. Several states are recognizing that the current regulatory model may benefit from adjustments in order to provide different incentives to the utility, enabling it to better adapt to this rapidly changing industry. Most jurisdictions have maintained the core cost of service model with rate-based capital but have added, or are considering adding, discrete tools for specific actions. Some examples include improvements to interconnection processes for distributed resources, or allowing an incentive for peak load reduction, or performance incentives for avoiding distribution facility upgrades.

Adjusting the utility revenue model requires careful design to maximize positive outcomes while minimizing risk to ratepayers. The current regulatory structure has been successful for many years in achieving the desired outcomes identified by policy makers. Changing the incentive structure would require us to first identify the new values and new desired outcomes, and to determine how such outcomes might be measured and successfully achieved. To do this also requires us to establish both a metric to be measured and a baseline to measure success against, and to test whether achievement of the metric truly reflects utility performance.

Next Steps

Given changes in utility industry technology and policy drivers, as well as the opportunity to more effectively align utility incentives with desired public policy outcomes, the Commission will explore performance-based regulation. It is possible that utilization of performance-based incentives—allowing utilities to earn a return on the best performance outcomes rather than capital expenditures—will reduce competitive tensions while leading to best economic results for utility customers. We see the role of the regulator as designing economic incentives that align the interests of the utility and ratepayers, while we maintain our core statutory directives of safety, reliability, and just and reasonable rates for all customers.

A new proceeding will bring utilities and stakeholders together to explore a range of performance-based metrics for the specific utility systems that support the new desired system outcomes. Once identified, utilities and staff will track the data necessary to measure how well the current system is performing. With this information at hand, a future determination can be made as to which of the metrics lend themselves most appropriately to creation of incentives or penalties to achieve goals including overall system efficiency to the benefit of ratepayers.

From recent experience with a range of innovative pilots, we also find that the best learnings for new ways of thinking and working together may be achieved through taking small-scale actions, versus beginning with a long, extended study process with a goal of evaluating large-scale change. Proceeding with smaller-scale pilots will also enable the Commission, stakeholders, and utilities to more quickly evaluate decisions and proposals. In parallel with the identification of system metrics, we will also seek to identify desired utility actions without specific incentives or penalties today which, if incented or not, would likely lead to achievement of one or more desired outcomes for the system. Utilities would be encouraged to propose one to two limited-term, small-scale, new incentive tests to allow the Commission and parties the opportunity to gain experience in designing and integrating performance incentives into our practices.

Regional Market Development

A large number of SB 978 participants were encouraged by the success of the CAISO's EIM and indicated that the state and Commission should continue to explore further opportunities to share resources regionally.

Opportunity to capture efficiencies

Participants indicated that the presence of an Independent System Operator or a Regional Transmission Organization would provide a step toward improving conditions for robust competition, as it would open up a greater market for the sharing of resources beyond the real-time market benefits of the EIM.

The Commission has been engaged in conversations around the expansion of the CAISO into a regional entity beyond the borders of California. These conversations began most recently in April 2015, when PacifiCorp and CAISO signed a memorandum of understanding to explore PacifiCorp becoming a participating transmission owner in CAISO.[24] These conversations have slowed while the issue of governance[25] has been taken up by the California State Legislature. Oregon has indicated that governance is the key issue to be solved prior to moving forward with further regionalization efforts.[26] At the end of August, bills introduced in the California State Legislature to develop a path forward on governance failed,[27] though California could decide to take the issue up again in 2019.

Next Steps

With a balanced governance structure, greater regionalized sharing of resources could create efficiencies, support structures for wholesale competition, and provide cost-savings to Oregon customers. Deeper system integration across a broader geographic region will also grow in importance as a tool to reduce carbon emissions with added variable renewable generation. The Commission can only influence action in this area, but we commit to remaining actively engaged and contributing to the conversation around increased sharing of regional resources.

24 PacifiCorp, "New Participating Transmission Owner Memorandum of Understanding," April 13, 2015, http://www.pacificorp.com/content/dam/pacificorp/doc/7_MOU_PAC_ISO_4-14-15.pdf, accessed Aug. 11, 2018.

25 Governance is the term commonly used to refer to the structure of the CAISO Board of Directors. CAISO and its existing governance structure were developed by legislation that required certain representation on the CAISO Board. With the proposal to expand CAISO to the PacifiCorp states, there have been discussions on what the structure of the regionalized CAISO board should be and how states will be represented in decisions made by the regionalized CAISO.

26 Gov. Kate Brown, Letter to Gov. Jerry Brown, https://efiling.energy.ca.gov/GetDocument.aspx?tn=212260

27 RTO Insider, "CAISO Expansion Bill Dies in Committee,"", Sept. 1, 2018, https://www.rtoinsider.com/caiso-western-rto-99047/, accessed Sept. 5, 2018.

Participation

The Commission recognizes that a new approach to utility regulation is not limited to the incentive structure used to encourage certain behaviors and achieve performance outcomes from the regulated utilities; it must also include designing the regulatory process itself to allow opportunities for community-based organizations, members of the public, and stakeholders new to our process to expand participation.

Learning from new stakeholders

At the beginning of the SB 978 process, the Commission interviewed more than 20 organizations and individuals to better learn what aspects of the SB 978 process were most important to them. As part of these interviews, we talked with community-based organizations (CBOs) that stressed the importance of enabling and encouraging participation of members of the public and new stakeholders in the discussions on re-envisioning the energy system. Members of the CBOs expressed an interest in participating in the Commission process, but also concerns around the technical knowledge and dedication of financial resources required to participate effectively in such a process.

In order to better understand the needs of members of the public and CBOs, the Commission applied for a Rocky Mountain Institute eLab Accelerator called Forge. This program was two and a half days of intensive, facilitated conversation with participants in the SB 978 process. Our goal was to better understand what elements of the Commission's process form a barrier to entry and also provide opportunities for participants to better understand the types of processes the Commission utilizes and for what purposes. We are grateful to the organizations[28] that took the time to travel to New York State to participate in the Forge process.

Beyond the Forge process, SB 978 participants took time to educate the Commission on their perspectives on participation in Commission processes. Things we learned during the SB 978 process include:

1. Some members of the public and communities have been historically marginalized and their perspectives have not been represented in the Commission process. This marginalization has happened for a number of reasons, including educational, process, and capacity barriers. These groups should be enabled to meaningfully participate in Commission processes. Such participation will better inform and provide a greater diversity of perspectives on matters before the Commission.

2. Some Commission cases, also known as dockets, can require complex technical and legal processes, especially when matters of fact are in dispute, property rights are involved, and high costs to ratepayers are anticipated. In these contested case proceedings, parties that wish to participate must petition to intervene and provide reasons of their interest in the case to the Administrative Law Judge; such petitions are typically granted. Contested Case proceedings determine the rights of individual parties and frequently involve highly technical and legally complex issues. As a result, they often require the exchange of evidence though discovery, submission of expert witness testimony, cross-examination hearings to test the veracity of witness testimony, and legal briefing when legal disputes arise. Other Commission processes, such as regular Public Meetings and rulemaking dockets, are more informal and the barriers to participation are lower, however, barriers may still exist even in these informal processes. One significant barrier identified is an understanding of the required Commission processes, how stakeholders can engage, how they can be informed about upcoming proceedings, and which proceedings would be most appropriate and impactful for them to engage in.

3. When issues have been deemed of significant interest to the public, the Commission has hosted public comment hearings or "listening sessions" in the communities impacted by these decisions. This approach allows community members an opportunity to voice concerns in front of the Commission without engaging in a complex regulatory proceeding. However, stakeholders note that how the Commission makes the decision on when and where to hold these meetings, as well as whether the Commission can consider the input from these public meetings in its decision-making, is unclear.

4. Developing educational materials and opportunities for participation is an important piece of increasing open access to the Commission process.

5. Engagement in the Commission process is beneficial, however, members of the public and new stakeholders need to understand how their comments and input will be considered as part of the regulatory process in order for it to meet the requirements of being fully inclusive.

Members of the public, new stakeholders, and community-based organizations should play a key role in the design and creation of the energy system that leads us into the future. However, there can be barriers to participation in public process and legal limitations to removing these barriers in contested case processes. The Commission also acknowledges that a targeted approach to engaging and meaningfully involving low income, environmental justice, and other historically marginalized communities in decision-making processes would provide a more complete set of perspectives for consideration.

28 Northwest Energy Coalition, Multnomah County, Asian Pacific American Network of Oregon, OPAL Environmental Justice, Portland General Electric, Verde, Oregon Citizens'Citizen's Utility Board, and the Regulatory Assistance Project.

The PUC draws a distinction between participation in public processes and procedural inclusion.[29] Here we reference the Urban Sustainability Directors Network definition of procedural inclusion which indicates that processes are inclusive, accessible, and there is authentic engagement and representation in the process to develop programs or policies. With our recommendations we aim to create an environment of procedural inclusion.

Further, the PUC understands that enabling broader participation and procedural inclusion will not only benefit members of community-based organizations and members of the public, but third-party technology providers, advocacy organizations, and others will find engagement in the Commission's process easier as well. One of the keys to broadening participation, however, is needed funding for CBOs to participate in Commission processes.

In 2003, the Oregon Legislature passed SB 205, which allowed investor-owned utilities to enter into financial agreements with organizations which represent broad customer interests before the Commission. These agreements provide intervenor grant funding for organizations like the Citizens' Utility Board and the Alliance of Western Energy Consumers to participate in regulatory proceedings before the Commission. Organizations must apply to the Commission in order to receive intervenor funding, generally for specific regulatory proceedings in which they are representing broad customer interests.

During the SB 978 process, stakeholders worked with utilities to develop a limited intervenor funding agreement to provide funds for the participation of CBOs as part of the SB 978 process, which the Commission approved on September 11, 2018.

The ability to provide intervenor funding is limited, as the statutory authorization for such agreements is limited to "organizations that represent broad customer interests in regulatory proceedings conducted by the Public Utility Commission."[30] This is because intervenor funds are ultimately collected from ratepayer classes that benefit from the participating organization. For example, intervenor funding received by the Citizens' Utility Board is collected directly from all residential ratepayers.

Next Steps

The PUC commits to continue working with stakeholders to understand and develop opportunities for greater procedural inclusion and education. As previously discussed, SB 420 requires the Commission to enable the public to access its process in dockets that involve environmental justice issues. It also required the creation of a Citizen Advocate[31] position within each of the impacted natural resource agencies. The Commission utilizes its Citizen Advocate position to engage in matters with the Environmental Justice Task Force, as well as provide information to the public, however, with an increased focus on participation, the Commission recognizes utilizing this position differently may be warranted.

We commit to developing a strategy for engagement that we will carry forward beyond the SB 978 process, to create tools on our website that lead to a greater understanding of the Commission's role and processes, enhance our Citizen Advocate position, and develop tools to assist community-based organizations and others in navigating the Commission's processes. We will work to develop materials for the public like those found in Appendix F, to assist with our educational outreach.

To enhance and promote the participation in Commission proceedings for organizations representing environmental justice or low-income issues, the Legislature could expand provisions authorizing financial assistance (intervenor funding) in Commission proceedings, which could be collected from potential new rate classes benefiting from their participation. Alternatively, the Legislature could create a low-income and environmental justice advocate. We understand that it may not be financially feasible for community-based organizations to develop the expertise required to engage in complex regulatory proceedings. This position would represent low-income ratepayers and those impacted by social and environmental justice issues in matters before the Commission, as well as ensure that environmental justice impacts are heard and included as part of the proceeding and information the Commission reviews in making decisions. This position could be housed in an existing agency. The responsibility of this position would be to represent low-income ratepayers in matters before the Commission, including rate cases and other contested case proceedings.

29 Meister Consultants Group", "Framework for an equitable energy supply transition, http://www.mc-group.com/wp-content/uploads/2017/08/MCG_Framework-for-an-Equitable-Energy-Supply-Transformation.pdf, accessed Aug. 11, 2018.

30 ORS 757.072.

31 Some SB 978 participants have noted that the term "citizen advocate" is exclusionary to immigrants and refugee stakeholders. The Commission uses this term as it is the legislatively adopted term used in SB 420, Sect. 4(4), however, it is open to developing a more inclusionary term for internal processes.

SUMMARY OF RECOMMENDATIONS AND ACTIONS

SB 978 is neither the beginning, nor the end, of the conversation about how the electric regulatory system will adapt to today's industry trends and policy objectives. The PUC has already begun that adaptation, and the SB 978 process provided the Commission and stakeholders a framework for broader dialogue around emerging system objectives and regulatory tools.

The PUC stands ready to use the powerful tools of economic regulation—traditional and evolving—to help achieve the objectives that the Legislature prioritizes for Oregon's regulated electric utilities. The PUC's roadmap, captured in our six priority action areas, represents a dynamic strategy to update and clarify PUC objectives and develop modern regulatory tools, market structures, and processes to achieve those objectives.

Climate Change: Address the regulated electric sector's role in mitigating climate change, as directed by the Legislature.

- Work with the Legislature and stakeholders toward an ***appropriate role in greenhouse gas mitigation*** that is consistent with the Commission's primary function as an economic regulatory agency.
- Work with the Legislature and stakeholders to appropriately define the electric sector's role, if any, in ***reducing emissions from other carbon-intensive sectors***, such as transportation.
- Continue to ***consider economic costs and risks associated with climate change*** and greenhouse gas regulation to ensure that utility systems are designed to accommodate cost-competitive, low-carbon technologies.

Affordability, Equity and Environmental Justice: Expand consideration of affordability and equity for all regulated utility customers.

- As part of the Low Income Utility Program Working Group, ***make recommendations*** to the Governor's Carbon Policy Office in December 2018 to address energy burden of low-income Oregonians.
- Assist, as requested, in ***legislative consideration of new ways to mitigate energy burden*** of low-income Oregonians, including changes to ratemaking laws that currently limit the Commission's authority.
- Explore ***differentiated service classification***s that may indirectly address energy burden within the Commission's current authority.
- Engage external resources to develop and ***host annual PUC staff training*** on social equity and environmental justice.
- Integrate ***environmental justice impact analysis*** into applicable rulemaking processes, and consider extending to other processes and continue to participate on the Environmental Justice Task Force.

Retail Customer Options: Encourage customer options that are fully and accurately valued.

- ***Encourage customer and competitive options*** that align with legislative and utility system goals.
- Reveal where and how customer and competitive options can provide maximum value to all customers, though increased ***transparency in distribution system planning***.
- Develop more consistent pricing methodologies for distributed energy resources in order to provide ***responsive pricing signals*** that keep pace with rapidly changing technology options.

Utility Incentive Alignment: Initiate performance-based regulation pilot programs and investigations.

- Launch a process to ***align utility incentives with customer objectives***.
- ***Invite proposals*** in areas where customers will benefit from the PUC allowing utilities to earn a return on outcomes rather than on capital expenditures.

Regional Market Development: Work toward a strong foundation for efficient wholesale competition and regional resource diversity.

- Participate with other states and agencies in ***regional forums to promote organized market development***.

Participation: Actively engage to promote greater participation from affected communities.

- Create tools and educational materials to assist community-based organizations and others in navigating PUC roles and processes to ***achieve greater procedural inclusion***.
- Assist, as requested, in ***legislative consideration of expanded funding for participation*** by low-income and environmental groups, whether through intervenor funding, a designated advocate, or other method.

This roadmap incorporates the issues of greatest interest to SB 978 participants and represents a new orientation for the Commission. It is a strategy for change that the PUC believes will most effectively achieve legislative goals and produce the best overall outcomes for all customers of Oregon's regulated electric system.

APPENDIX A: SB 978 PUBLIC PROCESS

SB 978 Public Process

SB 978 required the Public Utility Commission of Oregon (Commission or PUC) to establish a public process to investigate how developing industry trends, technologies, and policy drivers may be impacting the existing electricity regulatory system. Given the magnitude of examining our regulatory system, the Commission understood the importance of managing this process very differently than previous investigations hosted by the Commission. The Commission, which is an agency that has a very well-established process and approach to investigations, wanted to consider how to approach SB 978 differently and create a new, innovative path to cooperation with our stakeholders. The Commission understood that it would be important to ensure that stakeholders could work collaboratively together to help recommend solutions that would lead to constructive discussions from stakeholders even on topics which had recently created strife in our stakeholder community.

The traditional Commission process can at times be adversarial, where parties can be in opposition with one another. Recent significant cases and decisions that have come before the Commission have left stakeholder groups at odds with one another over some of the key issues we would investigate as part of SB 978. Those issues included competition, distributed energy resources, customer choice, and resource procurement. Also, there were new participants and stakeholders who had indicated an interest in participating in the Commission's process. How to integrate their voices in the process and ensure their full participation was an important goal established early in our process. In order to develop as comprehensive of an approach as possible for the different stakeholder needs the Commission's first step was to develop an internal project management team, whose task was to develop a process which would enable participation from a wide-variety of individuals and stakeholders and ensure participant collaboration. These were key elements leading to the outcomes developed at the end of the process.

Development of the Public Process

The SB 978 internal project management team included members of our Utility Division Staff (Elaine Prause, Jason Eisdorfer, and Julie Peacock), the Department of Justice (Kaylie Klein), Administrative Hearings (Michael Grant), and was led by a Commissioner (Megan Decker). This internal planning team determined that in order to have a holistic review of the system, the Commission would need to engage stakeholders early in the process to have a better understanding of in their own terms, what elements a comprehensive and open process would include.

The planning team interviewed more than 20 sets of stakeholders and individuals to gain a better understanding of what was desired from the SB 978 process. Feedback from stakeholders included:

- Ensuring new stakeholders and participants would be able to engage in the process by making it more approachable than the typical Commission docket process.
- Developing some capacity building aspects of the process to ensure a level starting point for discussions about changes.
- Ensuring the process timeline was clear to participants in the beginning, including number of meetings and timeline to completion.
- Utilization of third-party resources to assist the Commission in making the conversation more neutral and providing external expertise.

In response to the stakeholder interviews, the Commission developed an internal work plan which included strategies for integrating the feedback from participants and stakeholders. The first element was to consider external funding and the ability to utilize consultants to facilitate the meetings and provide the Commission with external expertise.

The Regulatory Assistance Project (RAP) was an invaluable partner in this process. They assisted in locating and applying for funding from The Energy Foundation, which allowed us to utilize their services and the services of the Rocky Mountain Institute (RMI). RAP acted as a technical advisor to the Commission, providing a national perspective on trends and investigatory processes in other states. RMI acted as a third-party facilitator, designing creative agendas and meeting structures which would enable the participation of a wide-variety of participants. We are grateful for the assistance provided by these organizations, which we found to be invaluable in designing a process which was innovative and approachable.

Together with RAP and RMI, the internal planning team designed a seven meeting process. These meetings are described briefly below.

SB 978 Meetings Structure

The meetings were broken into three phases; the first phase was an examination of the existing energy and regulatory systems; the second, was an investigation of the policy and technology trends driving the sector; and the third was to identify potential changes. The Commission began its process with an introductory welcome meeting in January which set the stage for the overall process.

January: The design of the January meeting was to provide an initial understanding of how the Commission was planning to proceed with the 978 process. It also functioned to provide opportunities for stakeholders to share initial thoughts around high-level goals and principles that they believed should guide regulation in the electric sector today. In advance of the meeting we provided stakeholders with reading materials which gave 1) A brief background on the efforts happening in other states; 2) A

JANUARY	FEBRUARY	MARCH
Activities: • Process Plan announced to stakeholders early Jan. • First external meeting, Jan. 30 • Engage a facilitator and external expertise ***Milestone:*** Develop an understanding of the process with stakeholders	Activities: • Engage stakeholders for presentations at the second external meeting • Develop framing paper or presentation for distribution prior to meeting • Second stakeholder meeting, Feb. 22 with an education focus on the topic of "investigation of the existing energy and regulatory system" ***Milestones:*** Development of framing paper, second external meeting and guiding principals	Activities: • Third external meeting with a focus on facilitated stakeholder conversation around "Investigation of the existing energy and regulatory system" ***Milestone:*** Allow opportunity for stakeholder comments on investigation to date
	Investigation of the existing energy and regulatory systems	
APRIL	**MAY**	**JUNE**
Activities: • Fourth stakeholder meeting with an education focus on the topic "Investigation of policy and technology trends" and general identification of trends • Report out from any subgroups that developed as a result of meeting three • Request that stakeholders file comments on trends ***Milestone:*** May request stakeholders file comments on trends and public policy objectives with views on how they impact the existing regulatory system	Activities: • Aggregation of any comments as a result of the previous meeting and distribution to stakeholders • Fifth stakeholder meeting with a focus on facilitated stakeholder conversation on "Investigation of policy and technology trends" ***Milestone:*** Allow opportunity for stakeholder comments on investigation to date	Activities: • Development of a framing document or presentation on potential changes to be distributed prior to the sixth meeting • Fifth stakeholder meeting with a focus on identifying potential changes ***Milestone:*** Development of a framing document for June meeting
Investigation of policy and technology trends		**Identify Potential Changes**
JULY	**AUGUST**	**SEPTEMBER**
Activities: • Optional seventh meeting • Finalize development of draft report for distribution to stakeholders in late July ***Milestone:*** Distribution of draft report in late July	Activities: • Stakeholder comments on draft report due • PUC will begin finalizing report ***Milestone:*** Stakeholder comments due	Activities: • File final report with the Legislature ***Milestone:*** Submittal of the final report to the Legislature by Sept. 15
Identify Potential Changes	**Final Report Preparation**	

list of questions to give stakeholders a broad overview of questions others have asked and; 3) A general framework of what traditional cost-of-service regulation includes.

February: This meeting included a discussion of the existing energy and regulatory system, with a focus on hearing stakeholder perspectives on the structure of the existing system. RAP provided a framing paper, "Basics of Traditional Utility Regulation and the Oregon Context," in which it described the traditional utility regulatory structure as well as a brief overview of Oregon specific context. The purpose of the framing paper was to provide participants with a foundation for discussion of the existing regulatory system. At the February meeting, participants self-selected into the following groups: customer and customer representatives, generation and service providers, utilities, environmental concerns, equity and environmental justice, and Public Utility Commission staff. These groups worked together between the February and March meetings to develop presentations for the Commissioners answering questions on their perspectives on the existing system. These presentations can be accessed here: https://www.puc.state.or.us/Pages/MarchMeetingPrep.aspx.

March: The self-selected groups identified above gave presentations on their perspectives on the existing system and how it is operating. Those presentations are available here: https://www.puc.state.or.us/Pages/

MarchMeetingPrep.aspx. Participants were also given an opportunity to provide comments to the Commissioners on the existing system, responding to specific questions that the Commissioners had about how the current construct was working.

April: This meeting focused on an investigation into policy and technology trends in the regulated electricity sector. RAP provided a framing paper to aid in the conversation called, "Trends in Technology and Policy with Implications for Utility Regulation". This framing paper has been provided as Appendix D in this report. The Commission also invited several national experts in technology trends to provide presentations at the meeting. These presentations included information from the NW Power Council, Pacific Northwest National Labs, Energy Innovation, Utopus Insights, Pacific Gas and Electric, and Energy Sage. Also during the day policy makers presented on the emerging policy trends they see impacting the regulated utility sector, these presenters included Sen. Lee Beyer (District 6), Rep. Ken Helm (District 34), and Milwaukie Mayor Mark Gamba.

At the end of this meeting participants again self-selected into groups to work on a collaborative activity. These groups included economic efficiency, customer choice, low-carbon future, and access. The groups were developed in response to the major emerging themes from the stakeholder meetings and the assignment provided participants an opportunity to work between meetings to develop memos to present to the Commission in May. These memos have been provided as Appendixes E-1, E-2, E-3, and E-4.

May: This meeting focused on further investigating policy and technology trends, by utilizing the memos and presentations created by our participants between the April and May meetings. Participants had the opportunity to develop a short presentation to the Commission, responding to these main questions:

Group 1: Economic Efficiency: Do our existing incentives lead to the most economically efficient outcomes? If not, how do we incentivize the most economically efficient outcomes?

Group 2: Customer Choice: How do we balance customer options and access to market and technology choice in a socialized system?

Group 3: Low Carbon Future: How can the regulated utility sector contribute to the transition to a lower carbon future? What is the role of regulators in decarbonization?

Group 4: Access: Is electricity an essential service to society, and if so, how does regulation ensure affordability and reliability for all customers going forward?

June: At its final collaboratively structured meeting, the Commission provided stakeholders with a memo which summarized its understanding of participants' perspectives in the SB 978 process to date (Appendix G) as well as six short memos from RAP that were used to form the starting point of conversations in the final meeting. These six memos focused on industry structure, low carbon policies, retail choices, distributed energy resources, utility incentives, and equity. They were designed to create conversation amongst participants leading into the final meeting. At the conclusion of this meeting participants engaged in a prioritization exercise that highlighted which areas of action seemed to have the most consensus and interest from stakeholders. After the June meeting, participants were given the opportunity to file comments for the Commissioners to consider as part of writing its report.

July: This meeting provided stakeholders with an opportunity to comment on their priority items for the SB 978 report, including what recommendations they felt would be important to include.

Participant List[32]

	Name	Organization
1	Marc Hellman	Alliance of Western Energy Consumers
2	Tyler Pepple	Alliance of Western Energy Consumers
3	Ann Fisher	Ann Fisher Legal and Consulting Services
4	Khanh Pham	Asian Pacific American Network of Oregon
5	Dan Meek	Attorney/Consultant
6	Evan Ramsey	Bonneville Environmental Foundation
7	Crystal Ball	Bonneville Power Administration
8	Nick Caleb	Center for Sustainable Economy
9	Bob Jenks	Citizen's Utility Board
10	Janice Thompson	Citizen's Utility Board
11	Liz Jones	Citizen's Utility Board
12	Mike Goetz	Citizen's Utility Board
13	Will Gehrke	Citizen's Utility Board
14	Andria Jacob	City of Portland
15	Diane Henkels	Cleantech Law Partners
16	Mark Darienzo	Climate Jobs PDX
17	Dave Van't Hof	Climate Solutions
18	Meredith Connolly	Climate Solutions
19	Maggie Tallmadge	Coalitions of Communities of Color
20	Keith Kueny	Community Action Partnership of Oregon
21	Brian Skeahan	Community Renewable Energy Association
22	Thor Hinckley	Consultant/Climate Solutions
23	Jay Ward	Energy Trust of Oregon
24	John Volkman	Energy Trust of Oregon
25	Jeanette Shaw	Forth
26	Pamela Morgan	Graceful Systems
27	Amy Schlusser	Green Energy Institute
28	Lev Blumenstein	Green Energy Institute
29	Natascha Smith	Green Energy Institute
30	Melissa Powers	Green Energy Institute

	Name	Organization
31	Lisa Nordstrom	Idaho Power Company
32	Lisa Rackner	Idaho Power Company
33	Mark Annis	Idaho Power Company
34	Riley Peck	Industrial Customers of Northwest Utilities
35	Sara Baldwin Auck	Interstate Renewable Energy Council
36	David Lowrey	Itron
37	Bill Holmes	K&L Gates
38	Ken Kaufmann	Ken Kaufmann Attorney at Law
39	Alan Hickenbottom	Latitude45 Associates
40	Beth Reiley	Legislative Policy and Research Office
41	Mark Monlux	Monlux Illustration
42	Tim Lynch	Multnomah County
43	Angus Duncan	Natural Resources Defense Council
44	John Tillman	Nissan North American, Inc.
45	Bob Kahn	Northwest and Intermountain Power Producers Coalition
46	Irion Sanger	Northwest and Intermountain Power Producers Coalition
47	Sidney Villanueva	Northwest and Intermountain Power Producers Coalition
48	Oriana Magnera	Northwest Energy Coalition
49	Wendy Gerlitz	Northwest Energy Coalition
50	Melinda Eden	Northwest Energy Efficiency Alliance
51	Kerry Meade	Northwest Energy Efficiency Council
52	Leann Bleakney	Northwest Power and Conservation Council
53	Gail Hammer	NW Natural
54	Mark Thompson	NW Natural
55	Zach Kravitz	NW Natural
56	David Brown	Obsidian Renewables

32 This participant list was developed from RSVPs received by the Commission prior to each stakeholder meeting. It may not be exhaustive, however, it does reflect the broad range of stakeholder participation the Commission experienced during the SB 978 process.

	Name	Organization
57	Laurie Hutchinson	Obsidian Renewables
58	Maria Hernandez	OPAL Environmental Justice Oregon
59	Cameron Brooks	Opus One Solutions
60	Megan Chrissman	Oregon Business and Industry
61	Adam Schultz	Oregon Department of Energy
62	Diane Broad	Oregon Department of Energy
63	Jason Sierman	Oregon Department of Energy
64	Lesley Jantarasami	Oregon Department of Energy
65	Rebecca Smith	Oregon Department of Energy
66	Ruchi Sadhir	Oregon Department of Energy
67	Wendy Simons	Oregon Department of Energy
68	Cory Ann Wind	Oregon Department of Environmental Quality
69	Jana Gastellum	Oregon Environmental Council
70	Jennifer Joly	Oregon Municipal Electric Utilities Association
71	Damon Motz-Storey	Oregon Physicians for Social Responsibility
72	Brittany Andrus	Oregon Public Utility Commission
73	Caroline Moore	Oregon Public Utility Commission
74	Lance Kaufman	Oregon Public Utility Commission
75	Marianne Gardner	Oregon Public Utility Commission
76	Ming Peng	Oregon Public Utility Commission
77	Seth Wiggins	Oregon Public Utility Commission
78	Phil Barnhart	Oregon Representative
79	Jon Miller	Oregon Solar Energy Industry Association
80	Rebecca Langer	Oregon State University MPP Student
81	Evyan Andries	Oxley & Associates, Inc.
82	Ajay Kumar	PacifiCorp
83	Cynthia Mifsud	PacifiCorp
84	Erin Apperson	PacifiCorp
85	Etta Lockey	PacifiCorp

	Name	Organization
86	Natasha Siores	PacifiCorp
87	Scott Bolton	PacifiCorp
88	Pete Danko	Portland Business Journal
89	Kris Allman	Portland Democratic Socialist of America
90	Emily von W. Gilbert	Portland Democratic Socialists of America
91	Jordan Sheldon	Portland Democratic Socialists of America
92	Ryan Conifer	Portland Democratic Socialists of America
93	Brett Sims	Portland General Electric
94	Brianne Hyder	Portland General Electric
95	Dave Robertson	Portland General Electric
96	Franco Albi	Portland General Electric
97	Jacob Goodspeed	Portland General Electric
98	Jay Tinker	Portland General Electric
99	Loretta Mabinton	Portland General Electric
100	Margo Bryant	Portland General Electric
101	Maty Sauter	Portland General Electric
102	McKena Miyashiro	Portland General Electric
103	Alex Hassen	Power Oregon
104	Eric Strid	Power Oregon
105	Craig Patterson	Public Participant
106	Leah Gibbs	Public Participant
107	Norm Cimon	Public Participant
108	Rich Peppers	Public Participant
109	Marie Barlow	Renewable Energy Coalition
110	Max Greene	Renewable Northwest
111	Silvia Tanner	Renewable Northwest
112	Amy Hojnowski	Sierra Club
113	Jeremy Fisher	Sierra Club
114	Laura Stevens	Sierra Club
115	Miriah Elliott	Sorenson Engineering
116	Jaimes Valdez	Spark Northwest
117	Fuji Kreider	Stop B2H
118	Jim Kreider	Stop B2H
119	Meredith Shield	Strategies360
120	Alec Shebiel	Umatilla Electric Cooperative
121	Jacques Grant	YAM Services

APPENDIX B: HISTORY OF THE PHYSICAL AND REGULATORY SYSTEM

History and Basics of the Physical System

The existing physical electric system is based on an interconnected system of transmission, distribution, and generation. In some cases, generation is owned and operated by entities that are not responsible for providing service to end use customers. In addition, sometimes generation must cross multiple jurisdictions prior to reaching its end use. This section briefly describes utility service territory, the interconnected electric system, and the role of reliability organizations and balancing authorities.

IOU Service Territories

The Commission regulates three investor-owned electric utilities (IOUs) (Portland General Electric, PacifiCorp, doing business as, Pacific Power, and Idaho Power), three investor-owned natural gas utilities (Northwest Natural Gas Company, Avista Corporation, and Cascade Natural Gas Company) more than 350 telecom companies, and about 80 small water companies. SB 978 asks the Commission investigate trends in the electricity sector, narrowing the scope of the discussion to the companies, customers, and regions listed in the table below.

Table 1. 2016 Electric IOU Statistics[32]

Company	Number of Oregon Customers	% of Oregon Customers Served	% of Total Company Customers in Oregon	Annual Revenues ($million)	Annual Retail Sales (MWa)
Idaho Power	18,848	1%	<5%	$53	76
PacifiCorp	574,131	29%	~25%	$1,275	1,469
Portland General Electric	859,396	44%	100%	$1,704	1,969
TOTAL	1,452,375	74%	NA	$3,032	3,514

Each utility service territory varies and is a mix of customer density (urban vs rural), age of transmission and delivery infrastructure, generation resource portfolio, customer demographics, geography, and regional economics. This diversity across and within utility territories leads to very different day-to-day operational issues and considerations for each utility, but the overall scope and basic practice of Commission regulation is consistent across all three utilities.[34]

The Interconnected Electrical System

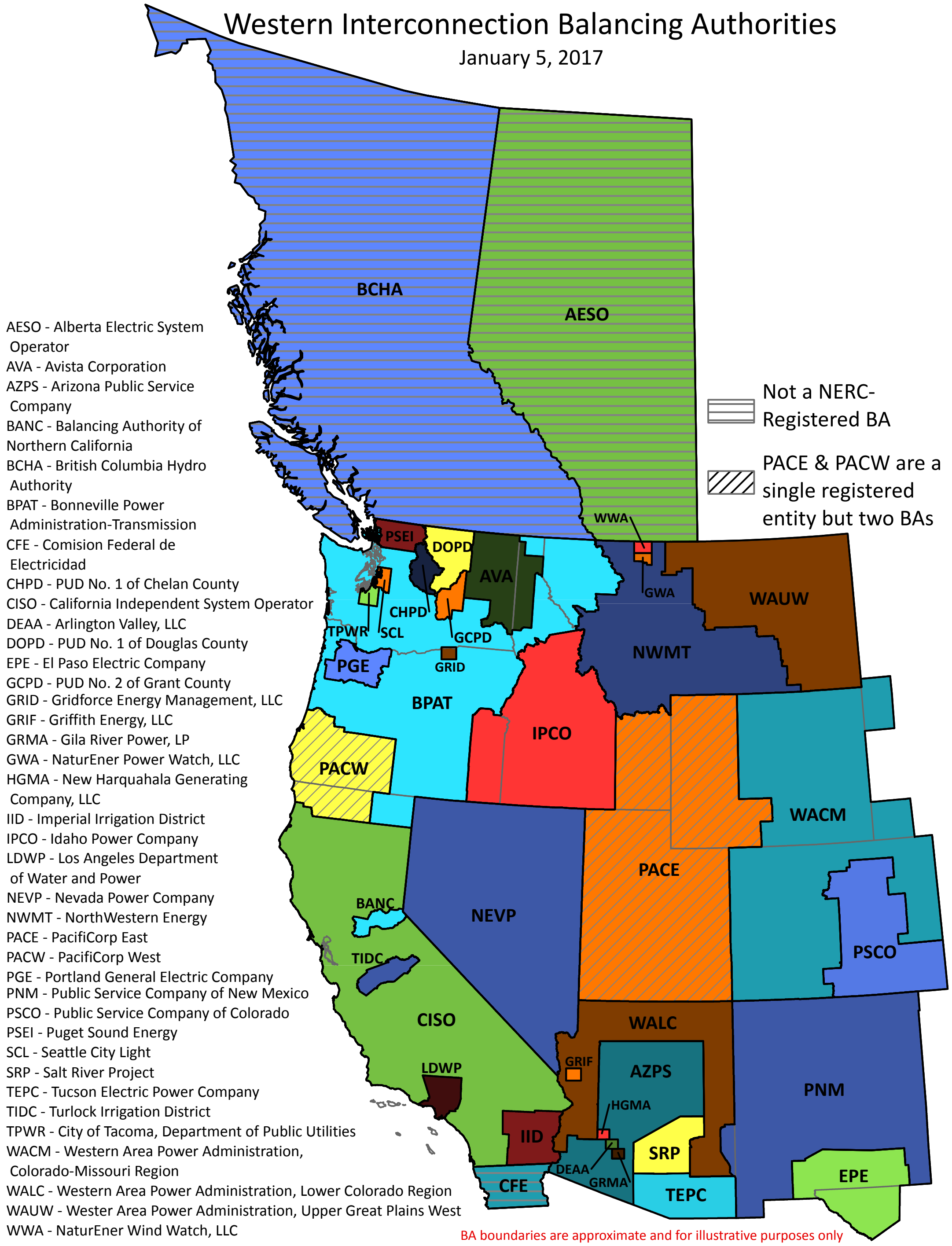
All of the electric utilities regulated by the Commission are "vertically integrated" meaning they own (or can own) and generate, or directly contract for all of the energy they deliver to their customers through their transmission and distribution system. Transmission can be utility owned or contracted from another party but delivery of energy services to the end use customer site is through utility-owned distribution system infrastructure.

Individual utility operations and investments have impacts on the reliability of the regional grid and therefore how the utilities make daily and long-term decisions is greatly influenced by the larger system requirements within which they operate.

Oregon utilities are located within the Western Interconnect, one of three independently operating grid systems in the U.S. where all of the connected electricity is "synchronized" to the same frequency. This network of generation, transmission, and distribution lines is the interconnected physical system across which power is

33 Oregon Utility Statistics Book, 2016, https://www.puc.state.or.us/Pages/Oregon_Utility_Statistics_Book.aspx

34 In recognition of the impacts to smaller services territories in the states, the Oregon Legislature have exempted small utilities from certain regulations. For example, ORS 757.601(c) exempts IOUs with less than 25,000 customers from the state's direct access regulation.



constantly flowing. The management of the system is done through Balancing Authorities which are mostly electric utilities that. are required to ensure that their system supply and demand are balanced at all times. PacifiCorp's system is managed through two balancing authorities, PAC-East and PAC-West, while PGE and Idaho Power operate as single balancing authorities. Without this balance of supply and demand, local and widespread blackouts can occur.

The National Electric Reliability Council (NERC) enforces reliability standards for all balancing authorities through the Western Electricity Coordinating Council (WECC) and its coordination of reliability, short- term and long-term planning of operations. While other regions in the U.S. have Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to control and monitor the grid as wholesale market operators, in the Northwest, wholesale sales are transacted bilaterally through direct party negotiations via brokers. In 2014, the California ISO created a real-time market, the Energy Imbalance Market (EIM), which has expanded throughout the west in the last several years. All three electric IOUs operating in Oregon are members of the EIM and have reported net benefits since joining. Each hour, they nominate owned generation resources to the real-time market for regional system balancing while maintaining control and responsibility for balancing their own systems.[35]

History and Basics of the Regulatory System

In the last decades of the 19th Century, when the electricity industry was beginning to develop, economic realities and public policy goals influenced how electric utility regulation would evolve over the next 100 years. Economically, it was clear that multiple companies competing to provide distribution services to a neighborhood would result in an inefficient and dangerous jumble of redundant distribution lines. The substantial amount of capital necessary to develop the costly electricity-generating units and transmission lines tended to favor large single investors who could raise capital at lower cost rather than multiple small providers competing to make investments for new and uncertain customer needs. These economic realities led to the conclusion that a single, vertically integrated provider could deliver lower cost electricity to customers more reliably than multiple competing providers.

At the same time, the public began to utilize electricity both for home and business on a rapidly increasing basis. Electricity was increasingly becoming vital to all aspects of society from the larger economy to the smallest household because of its versatile role in economic development and everyday comfort. As a result, policy makers and courts determined that electricity had become an essential service affected with the public interest," and policy makers concluded that electricity service should expand to all reaches of the country, that it be safe and reliable, that it must be offered to everyone in a nondiscriminatory manner.

As the industry developed into large, single-provider systems, it became necessary to protect society from unfair practices by these new large companies. As a result, federal and state governments quickly introduced regulation in order to ensure that the public had safe, reliable, and non-discriminatory access to this essential service at reasonable rates when no competition existed to discipline the market.

Modern utility regulation was born with the concept of the "regulatory compact" as an implicit agreement between government and any for-profit utility, allowing the utility to operate as a protected monopoly in a geographic service area in exchange for consenting to be regulated by governmental entities. The utility was required to serve anyone located within its exclusive service territory in a manner that was safe, reliable, nondiscriminatory, and fairly priced. In exchange, the utility was allowed to collect in its rates all reasonable operating expenses and all prudent capital investments, with an opportunity to earn a set rate of return on the capital investments it made in the electricity system to serve customers.

Given the early policies of affordable universal electricity service, the regulatory structure was designed to encourage utility investors (shareholders) to invest large amounts of capital in the electricity system. This was necessary to ensure that enough generation was built to serve the growing electrical loads of customers, and to build a distribution system that was reliable and accommodated new customers safely and efficiently. State utility regulators developed regulatory tools and mechanisms to support financial incentives for utility shareholders to invest in the electrical system, while at the same time protecting captive customers from utility over-investment that would lead to higher-than-necessary rates. The goal was to achieve an economically efficient electricity system that served the needs of individual customers and a growing economy.

Basic Regulatory Structure

The regulation of rates for the purpose of promoting the health, comfort, safety and welfare of society is an exercise of the police power of the state.[36] The regulation of public utilities and the fixing of rates constitutes a legislative function and the Oregon Legislature has granted the Public Utility Commission the broadest authority to exercise this function.[37] The authority conferred upon the PUC is described in its statutes, with the legislature charging the PUC with the responsibility to represent utility ratepayers and the public generally in all controversies respecting rates, valuations, service and all matters the PUC has jurisdiction over and to protect ratepayers from unjust and unreasonable rates.[38] To ensure that customers have access to safe, reliable, and high quality service at reasonable rates, the PUC has authority to determine rates, promulgate customer protection rules, and oversee distribution system safety, among other regulatory activities. However, the PUC's authority is limited by the scope granted to it by the Legislature and by the state and federal constitutions. As a result, the Commission cannot take actions or require the utilities to take measures which are outside the scope of its statutory authority.

Utility regulation utilizes a system of incentives designed to promote specific positive customer outcomes or policy objectives. Most of these incentive mechanisms are designed to affect the behavior and performance of utility management and its shareholders, however some incentives, such as rate design, are developed to impact the behavior of the end use customer. The regulatory incentive mechanisms that encouraged the utility to grow the electrical system to ensure that all new load is served have been highly successful in achieving that policy objective. However, no incentive mechanism is perfect, especially in an increasingly complex system, or as preferred societal outcomes change and evolve. For example, the incentive for the utility to invest capital in the electrical system as a way to earn a return on its investment may also cause shareholders to seek to solve all problems or new state policy goals with more capital investment, rather than exploring less capital intensive alternatives. Over time, new regulatory mechanisms were developed and implemented

35 https://www.westerneim.com/Pages/About/default.aspx

36 City of Woodburn v. Public Service Commission of Oregon, 82 Or. 114, 1916.

37 Pacific NW Bell Telephone v. Sabin, 21 Or. App. 200, 1975.

38 ORS 756.040.

by the PUC, while existing mechanisms also evolved, to reduce unintended consequences of incentives without disrupting the core function of utility regulation.

Today, there are several key mechanisms that underpin the regulatory objective of an efficient and reliable system with fair rates. We explore some of the mechanisms below as examples of the core regulatory incentives and additional tools used to adjust for unintended effects of those incentives. These mechanisms include the ability to set rates, decoupling, integrated resource planning, power cost adjustment, and deferred accounting to name a few. This section will review how these mechanisms have traditionally worked.

Ratemaking and the Revenue Requirement

The utility business model is designed around the concept of the annual "revenue requirement," which is the forecasted amount of annual revenue necessary to cover operating expenses and capital investments, and earn a reasonable return on capital investments. The basic formula for the revenue requirement is as follows:

> Revenue Requirement =
> Operating Expenses + (Rate Base[39] x Rate of Return)

While reasonable operating expenses are recoverable from customers without a return on those expenses, the utility does have the opportunity to earn a return on its capital investments (rate base). As a result, the utility is incentivized to maintain steady investments in the utility system.

When a utility projects that its costs are growing beyond existing Commission-approved rates, or if the utility has a new capital asset serving customers that it wants to put into rates, it will file a rate case with the PUC. The utility will propose new rates by establishing a "test year" based on forecasted loads, expenses, capital additions, and known and measurable changes from existing rates. In the end, the utility is attempting to raise its annual revenue requirement to more accurately match the cost of providing service to its customers.

In practice, because the customer cannot choose another service provider and the utility is not subject to market competition, the regulator must design appropriate incentives akin to those found in a competitive market to align the behavior and performance of the utility with the interests of utility customers and applicable state policies. In rate cases, the Commission verifies, and in most cases, reduces the utility's cost assumptions that produce the proposed revenue requirement included in the rate case filing. This approximately nine-month review of assumptions is performed by PUC expert staff and stakeholders within the general rate case proceeding, or other ratemaking processes, prior to the Commission's order determining the allowable customer rates. The regulatory staff and other organizations representing utility customers will analyze the utility's load forecast to make sure the need for new capital investment is not inflated and question the proposed operating expense levels to avoid over-collection.

Staff and the parties will also question the prudence of new capital additions and determine the appropriate amount to allow into rate base. In a prudence determination, the parties are looking at whether the particular investment was reasonable given what is known at the time and is reasonably expected to benefit the ratepayer. Costs of investments not found to be prudent run the risk of not being recovered in rates. This is a form of a cost-benefit analysis which measures the relative cost of an investment against the range of benefits that will accrue to the customer. This is a recurring theme in regulation, although the form of the cost-benefit analysis might differ according to the investment, as with energy efficiency for example.

A key element of the rate case investigation is the determination of the proposed rate of return that a utility will earn on its capital investment in rate base. This rate of return is the incentive to the utility to invest capital, but it must be measured by the degree of risk to which the capital is exposed. In practical terms, the rate of return must be high enough to create an incentive to invest but not so high as to cause customers to overcompensate the investor beyond comparable risks in other industry sectors.

Once a revenue requirement is established, costs are allocated to customer classes based primarily on cost causality. Finally rates are designed for each class of customers to promote the efficient use of electricity.

The Commission will weigh the evidence in the record and issue an order establishing rates until the next rate case. If the utility can find operational efficiencies between rate cases, or if load grows beyond the assumed forecast, it generally can retain that value until the next rate case. This promotes innovative efficiencies between rate cases, but also creates an incentive to increase the amount of energy sold to customers.

This basic model of incentive regulation has been successful in creating robust utility systems where all load growth is served and outages are very rare. However, the system also rewards the utility for load growth and asset-based solutions to customer needs. In addition, because only prudent investments are recoverable, the utility tends to be risk-averse and invest in known technologies with lower risks.

Decoupling

Decoupling is designed to "decouple," or "disconnect," utility profits from the volume of energy it sells. This is because tying a utility's profits to the amount of energy sold creates a disincentive for the utility to invest in programs that reduce customer usage (sales volumes) such as energy efficiency or distributed generation. The decoupling goal is to make utilities indifferent to sales volumes. In a 1992 order, the Commission concluded that "decoupling - severing of the link between sales and profits - is necessary to fully achieve the goal of encouraging utilities to acquire

39 Ratebase is the remaining undepreciated book value of capital investments made to provide service, inclusive of other limited components such as working capital.

all cost-effective demand-side resources." Less than ten years later, the Energy Trust of Oregon was created to acquire all cost effective energy efficiency on behalf of electric utility customers, effectively removing the concern of misaligned utility motivation for acquiring energy efficiency.[40]

Integrated Resource Planning

In the 1980s, the Commission adopted one of the most significant non-ratemaking regulatory mechanisms: integrated resource planning.[41] Integrated resource planning requires in-depth consideration of all known resources for meeting the utility's forecasted load. In an integrated resource plan (IRP), the utility assesses system needs over a 20-year period and proposes an Action Plan over a two- to four-year period that demonstrates the least cost/least risk manner of serving expected load and meeting public policy goals. Per PUC guidelines,[42] the utility must consider generation, transmission and demand-side resources (energy efficiency, demand response, etc.) on a comparable basis. Both costs and risks are analyzed. Risks that are routinely examined include natural gas cost volatility, changes in load, and the cost of future environmental regulation, including potential carbon regulation.

The utility files an IRP within two years of its previous acknowledgment order and provides an annual update on the most recently acknowledged plan. Utilities seek to have the IRP "acknowledged" by the Commission, meaning the plan becomes a working document that can be referenced by the utility, the Commission, and the public in the prudence review stage of cost recovery in a rate case. However, acknowledgment does not guarantee that a utility will be able to include in rates the costs associated with the new resources proposed in their IRP. Through the IRP process, the Commission has required utilities to identify and justify reasonable least cost and least risk resource portfolios in a transparent manner. The details of implementing the plans in a prudent manner are evaluated in rate cases.

Special Treatment for Power Costs

Electric and gas utilities are permitted to recover their reasonably-incurred costs of service, including power costs, based on certain forecasts and projections. This process enables utilities to adjust rates every year to account for changes in energy markets or shifts in load forecasts in the coming year. A "true-up" process takes place every year where the actual power costs incurred to serve load are examined relative to the forecasted amount and the amount the utility collected from customer rates. Earnings that are significantly greater or less than what was projected are either shared with ratepayers (when the utility took in more than projected) or recovered from ratepayers (when the utility took in less than projected) based on previously agreed upon sharing bands.

Evolving Public Policy

The basic regulatory paradigm for investor-owned utilities remained largely intact through the 1990s when new policy goals related to market competition and environmental impacts of generation began to emerge and challenge the regulated monopoly business model. As generation technology evolved, the emergence of natural gas-fired generation with a smaller footprint and lower capital costs raised the possibility of non-utility generators to provide power. At the same time, some customers began to question whether they should be captive to a utility when there were developing alternative energy providers and renewable options. The desire to leave the utility to be served by another provider is complicated by the regulatory policy of the last 100 years where system costs have largely been socialized over all ratepayers. Attempts to leave the system necessitates contemplating how to allocate costs fairly among those who depart and those who stay with the utility.

The Oregon Legislature has addressed these and other policy developments through several major pieces of legislation since 1999. These major developments are described below.

SB 1149 (1999): created three significant changes in the energy system related to for-profit utilities (or investor-owned utilities). First, it partially deregulated electricity generation, allowing large commercial and industrial customers to purchase their electricity from an electricity service supplier rather than through the utility. The second was to create a public purpose charge which would be used to fund energy efficiency and market transformation, renewable energy, and low-income weatherization. The third was to require the IOUs to offer to residential and commercial customers a series of rate options with more renewable energy. In addition, SB 1149 started a ratepayer-funded low-income assistance fund.

- **Direct Access:** SB 1149 did not fully restructure the industry, but gave PGE and PacifiCorp customers more options from which to purchase their energy. All non-residential customers may purchase power from their current utility under a regulated cost-of-service rate or may opt for direct access through an Electricity Service Supplier (ESS) who would provide energy services at a rate negotiated by the ESS and the customer. Large non-residential customers that opt to switch to direct access must complete the requisite opt-out procedures, including paying a transition charge or credits to the utility to compensate for the impacts to the utility's system.

- **Public Purpose Charge:** under SB 1149, Portland General Electric (PGE) and PacifiCorp were required

40 Idaho Power plans and operates its own self-directed demand-side management programs.

41 Docket No. UM 180, Order No. 89-507 at 1 (Or. P.U.C. Apr. 20, 1989) (adopting Least-Cost Planning (LCP) for all energy utilities in Oregon).

42 Docket No. UM 1056, Order Nos. 07-002 (Or. P.U.C. Jan. 8, 2007) and 07-047 (Or. P.U.C. Feb. 9, 2007) (correcting an inadvertent omission in 07-002). For additional refinements to the process, see Order Nos. 08-339 and 12-013.

to collect a three percent “public purpose charge” from their customers to be used to fund conservation in schools, cost-effective energy efficiency, energy efficiency market transformation efforts, above-market costs of new renewable energy resources, and low-income weatherization. This provision also allowed the PUC to choose a non-governmental entity to serve as the agent to acquire the energy efficiency and the renewable energy rather than relying on the utility. Subsequent to the passage of SB 1149, the Energy Trust of Oregon (Energy Trust), an independent, third-party nonprofit, was created to serve as the administrator of the public purpose funds related to energy efficiency and renewable energy. In 2003, NW Natural Gas and Cascade Natural Gas in 2007, asked Energy Trust to offer comparable services to their customers. Most recently, in 2017, Energy Trust began providing services for Avista Corporation in Oregon.

- **Portfolio of Options:** PGE and Pacific Power were required to offer their customers a “portfolio of options” including a market-based rate and one which includes significant new renewable energy. The Legislature provided these options to customers who desired more choice in lieu of deregulating residential and small commercial customer service. The Commission also created an advisory group called the Portfolio Options Committee whose job it is to annually review the offerings of the utility’s and make recommendations for changes to the Commission.

SB 838 (2007): created two significant changes in the energy system. First, it created the state’s renewable portfolio standard and, second, it clarified that the PUC could require investment in all cost-effective energy efficiency.

- **Renewable Portfolio Standard and Automatic Adjustment Clause:** SB 838 established the Oregon Renewable Portfolio Standard (RPS), which required all Oregon electric utilities to deliver a percentage of their electricity from renewable resources by 2025.[43] SB 838 also included authority to establish a renewable resource automatic adjustment clause. This adjustment clause is unique amongst ratemaking mechanisms because it allows utilities to pass-through the cost of acquiring RPS-compliant renewable resources to ratepayers without filing a request for a general rate case, but subject to Commission review and approval. This alternative ratemaking mechanism allows the utilities to avoid regulatory lag and overcome the policy against single-issue ratemaking. The law includes customer protections in the form of a cost cap, where the utility no longer has to comply with the scheduled renewable acquisitions if the cost of compliance would raise the revenue requirement four percent higher than it would have been without the RPS.

  Incremental Energy Efficiency Funding: SB 838 also clarified that the PUC could require energy efficiency investments in rates above the public purpose charge instituted in SB 1149 if the PUC believed there was additional cost effective energy efficiency available. Large customers (greater than one average megawatt) were exempted so that they would not have to pay more than the public purpose charge but they also could not benefit from more energy efficiency at the customer site beyond what the public purpose charge would otherwise provide.

SB 1547 (2016): SB 1547 created three significant changes to the utility system. The first was increasing the state’s RPS requirements. Second, it required the state’s investor-owned utilities to remove coal from the rates of Oregon customers. Third, it created a community solar program. It also required the state’s investor-owned utilities to file transportation electrification programs with the Commission.

- **Amended Renewable Portfolio Standard:** SB 1547 increased the state’s RPS obligation for the largest, investor-owned utilities to 50 percent by 2040. It also eliminated the unlimited banking of renewable energy certificates (RECs), requiring that under certain conditions they no longer had unlimited life and would have to be retired five years after RECs were generated.

- **Coal to Clean:** SB 1547 required electric companies to cease allocating electricity from coal-fired generating units to the rates of Oregon customers on or before January 1, 2030.[44]

- **Community Solar Program:** SB 1547 required the Commission to adopt administrative rules to develop a community solar program. This program would allow customers to choose an energy provider, which could include an electric utility or a third-party provider. The utility is still the provider of services to the customer and the customer must enter into a separate contract with the community solar provider. This represents the first time residential and small commercial customers could in effect choose an energy provider beyond the base resource mix of the utility without having to develop their own energy resource, i.e., distributed solar.

43 The RPS was amended by SB 1547 (2016) which will be described later.

44 A similar restriction on nuclear power exists. The Energy Facility Siting Council cannot issue a site certificate for a nuclear-fueled thermal power plant until the federal government has established a repository for the disposal of high-level radioactive waste. ORS469.595. Further, even if the federal government establishes such a site, the Energy Facility Siting Council cannot issue a site certificate for a nuclear-fueled thermal power plant until such proposal is submitted to the electors of the state in a general election and the electors vote to approve the issuance of the certificate. *ORS* 469.597(1)-(2).

Other Tools

Beyond the significant omnibus energy bills noted above, the Commission has adjusted its regulatory incentives over time to respond to legislative mandates and to the changing demands, trends, and needs of customers and the IOUs it regulates. Below we summarize the most significant changes to the structure of regulation and incentives.

Competitive Bidding Guidelines

Through its Competitive Bidding Guidelines,[45] the Commission requires public utilities to conduct open competitive bidding when new power supply resources are needed that constitute a Major Resource acquisition, meaning for durations greater than five years and quantities greater than 100 MW. The utility is allowed to bid in the process, but it must treat all other bids fairly without preference for its own bid. A third-party, independent evaluator is employed in the process to ensure that the RFP if fair, transparent, and competitive. Currently, the Commission is engaged in a rulemaking to update the guidelines and promulgate them through administrative rules.

Greenhouse Gas Emissions Standard

In 2009, the Oregon Legislature passed the greenhouse gas emissions standard, which established new and more stringent greenhouse gas emission performance standards for power plants, essentially preventing the construction of new coal plants or the adoption of long-term coal contracts.[46]

Energy Storage Mandate

In 2015 the Legislature passed the second energy storage mandate in the country, requiring PGE and PacifiCorp to file plans with the Commission to invest in energy storage up to one percent of the utility's 2014 peak load. This allowed the utilities and stakeholders to explore technologies and the costs and benefits of energy storage.

In reviewing these policy developments, we find that the current system incentives and requirements look much different from the regulated system prior to 1999—it currently allows for customer choice to certain degrees, promotes acquisition of all cost effective energy efficiency, requires a minimum level of renewable resource acquisition, and requires competition in the acquisition of major resources.

45 The Commission's Competitive Bidding Guidelines were first adopted in 1991 and have been updated several times.

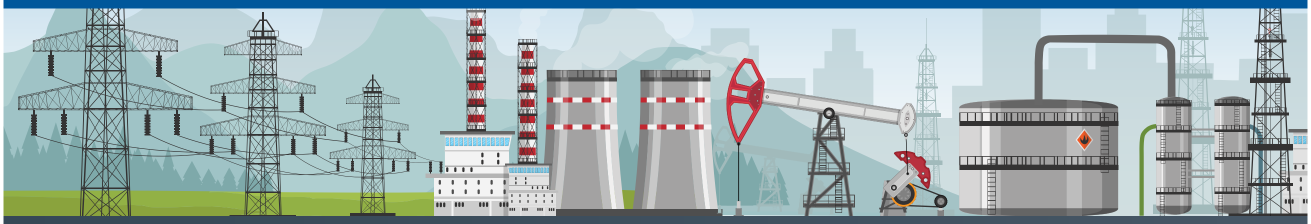
46 For more information on the greenhouse gas emission standard, see ORS 757.524.

APPENDIX C: TYPES OF UTILITY MARKET STRUCTURES

Oregon Public Utility Commission

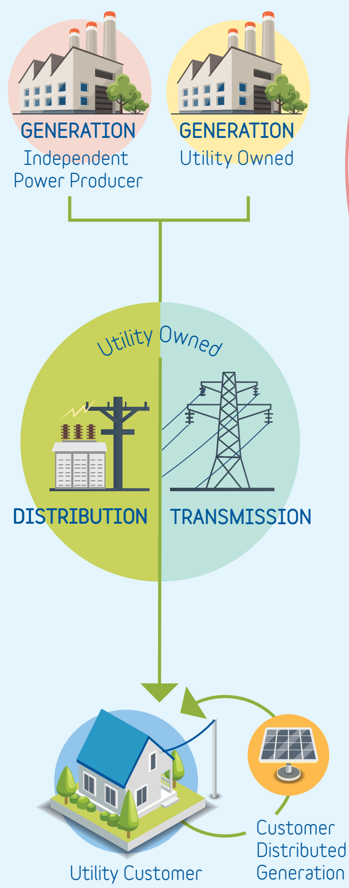
Types of Utility MARKET STRUCTURES

Each state, through its Legislature and Public Utility Commission, has developed an approach to regulating investor-owned electric utilities.

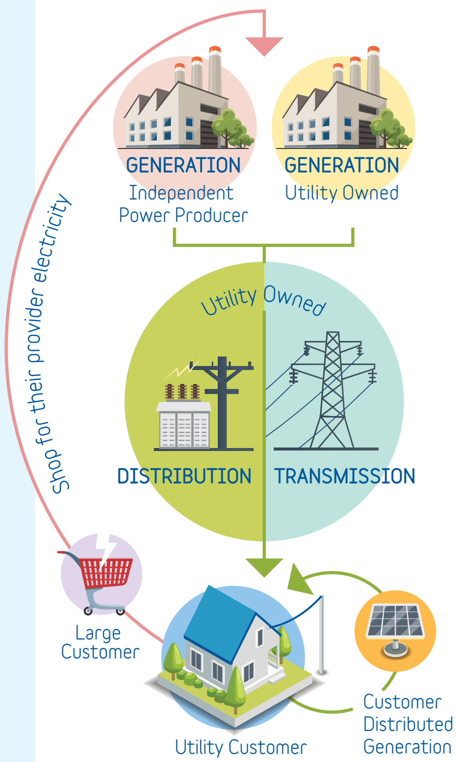


VERTICAL INTEGRATION

In some states, electric utilities can own all aspects of providing electric service to customers. This is known as being a vertically integrated state.



PARTIAL DEREGULATION



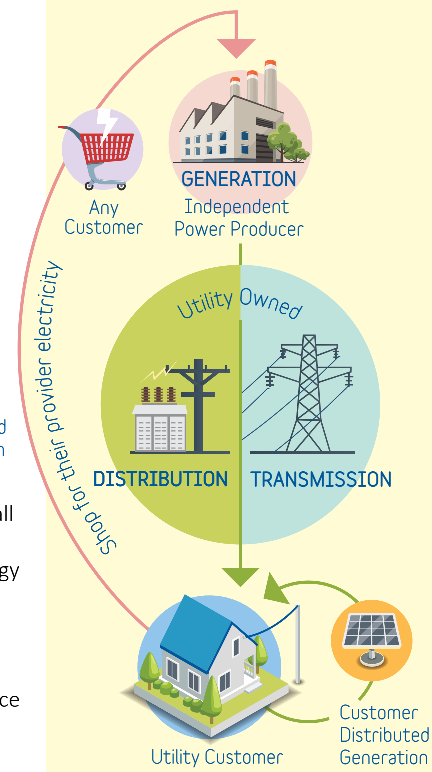
In these states, electric utilities can own all aspects of providing utility service, but non-utility power producers can sell energy to customers using the utility delivery (transmission and distribution) system.

In Oregon, for example, large customers can directly contract with electricity service suppliers to provide energy, but they still receive distribution and transmission services directly from their utility.

DEREGULATION

A third approach is total deregulation. In these states, utilities act as distribution and transmission utilities.

Customers can select an electricity supplier based on any number of factors, including price or whether it is emissions free.



APPENDIX D: REGULATORY ASSISTANCE PROJECT TRENDS IN TECHNOLOGY AND POLICY WITH IMPACTS FOR UTILITY REGULATION

April 2018

Trends in Technology and Policy with Implications for Utility Regulation

Carl Linvill, John Shenot, and Jessica Shipley

Many of the core elements of the electric utility business model, rate designs, and economic regulation evolved in an era when there was no practical or technologically feasible alternative to monopoly electric utilities satisfying all the generation, transmission, and distribution needs of their customers. Much has changed in recent decades. We've seen an explosion of available data about the production and use of energy, the emergence of independent power producers, competitive wholesale electricity markets, retail energy supply competition (i.e., direct access), behind-the-meter generation and storage, digital communications, and smart meters. At the same time, customers are exploring new choices for energy supply, delivery, use and storage in ways that challenge traditional regulatory models. These trends and innovations are raising questions about whether and how utility business models, rate designs, and regulatory processes need to evolve or change. To understand why that might be necessary or helpful, we will examine the major trends that raise these questions with the objective of providing fodder for discussion among stakeholders and staff about their relevance and importance to Oregon.

Evolving Customer Desires

The power sector is being driven to be more responsive to customer needs than ever before. Customer needs are being expressed through statute, such as renewable portfolio standards and net-energy metering policies, through direct demands to the utility from businesses, cities or individuals, and through the creation of new choice mechanisms, such as retail choice or community choice aggregation. Utilities and regulators are adapting to these new demands, and the result is likely to be continuing growth in renewable resources, increasing adoption of distributed energy resources, and introduction of new resources like electric vehicles. A consequence of these new sources of energy, energy demand, and energy services is a grid that is becoming much more "transactional." The grid of the past was characterized by one-way flow of electricity from suppliers to customers. The grid of the future is characterized by two-way flow where customers are not merely recipients of services but also suppliers of services to the grid.

A growing number of customers are demonstrating interest in the ability to control their usage, control their bills, and source their energy from clean sources. For example, large corporations are committed to purchasing 100% renewable energy[1], and whole cities and counties including Portland and Multnomah County in Oregon are committing to similar targets. Individual consumers participate in voluntary green power purchase programs[2] and demand response programs where they are available.[3] Recent surveys of electricity customers show broad support for renewable energy, a desire to have access to more data about their energy use and the option to be served on a time-of-use rate schedule.[4] In addition, technology is enabling passive participation by customers in energy choice and management through new capabilities and controls built into buildings and end-use equipment. This trend toward customer choice and control is particularly important for consumer-facing companies that have corporate clean energy or climate goals. Access to inexpensive, reliable, clean energy can impact decisions about where these companies locate and expand, and whether they close existing facilities.

Individual customers may value on-site or clean energy as a way to reduce the risk of price increases from delivered energy, or as a way to promote carbon reduction, and thus may seek to use energy that exceeds State goals or mandates.[5] Private renewable energy and carbon goals are bringing private capital into play and thus beginning to make meeting and exceeding State goals less expensive for the average ratepayer than it would have been otherwise. Customers who choose to participate in voluntary green pricing programs that support cleaner energy portfolios don't contribute capital, but they pay a premium that supports maturation of clean energy technologies. That is, well-designed policies can attract private capital, move society down the clean energy cost curve and can reduce costs for all ratepayers.

Customer choices can also help mitigate or even reduce electricity cost when they offer services to the utility (or the wholesale grid, in organized markets where this is enabled). For example, customers who use smart inverter technology to connect their distributed generation resource can offer frequency response service to the distribution utility. Customers who choose energy efficiency measures that shape their load to complement grid resource availability are contributing to keeping costs down for all customers because well-shaped loads contribute to deferring grid infrastructure investment. Similarly, with the proliferation of electric devices, appliances, and growing adoption of heat pumps and electric vehicles, customers can provide a range of services to the grid by

1 For example: Facebook, Intel, and Nike

2 Portland General Electric has the highest customer participation rate in green power purchasing programs in the country, and Pacificorp is in the top 3 in terms of total number of participants. For more information, see: National Renewable Energy Laboratory (2018) Voluntary Green Power Procurement. Golden, CO. Retrieved from: https://www.nrel.gov/analysis/green-power.html

3 For the past 30 years Great River Energy (GRE) has deployed electric water heaters in homes to manage loads. Today more than 110,000 homes – around 20 percent of its to customer base – have water heaters that collectively, according to the utility, amount to a gigawatt of storage.

4 Smart Energy Consumer Collaborative. (2018, February). 2018 State of the Consumer. Atlanta, GA: Smart Energy Consumer Collaborative. Retrieved from: https://smartenergycc.org/research/secc-research/seccs-2018-state-of-the-consumer-report-summary/

5 Some communities, primarily in California to-date, are choosing to adopt clean energy goals and implement them through "community choice aggregation" which goes half-way toward municipalizing utility services. The distribution utility continues to own, operate and plan the distribution system but the community assumes responsibility for procuring the energy resources to meet community needs. The portfolio of resources that it procures may include resources within the community, from behind the customer meter, like demand response or distributed generation, and it may include resources located outside the community. Accountability for meeting community goals and needs is ensured through community governance, whereas for investor-owned utilities accountability is ensured through PUC regulatory oversight.

participating in smart charging programs or shifting their use to off-peak times of day. In sum, individual customers, cities and businesses can contribute to meeting and exceeding State goals cost-effectively when they adopt policies or measures that promote clean energy development and that support use of their distributed resources to meet customer and grid needs.

A more customer-centric grid raises a number of questions for regulators and stakeholders to grapple with. Will changing customer demands, in particular the desire for two-way energy flow, necessitate rethinking of utilities' role in the electric system? Will regulation need to change to support adoption of information, communications and system control technologies that underpin the new transactional grid? What entities, including utilities, will take on new responsibilities in co-creating the transformed grid? How will regulation need to evolve to ensure proper oversight and protect customers, while enabling innovation?

Falling Costs of Clean Energy Technologies

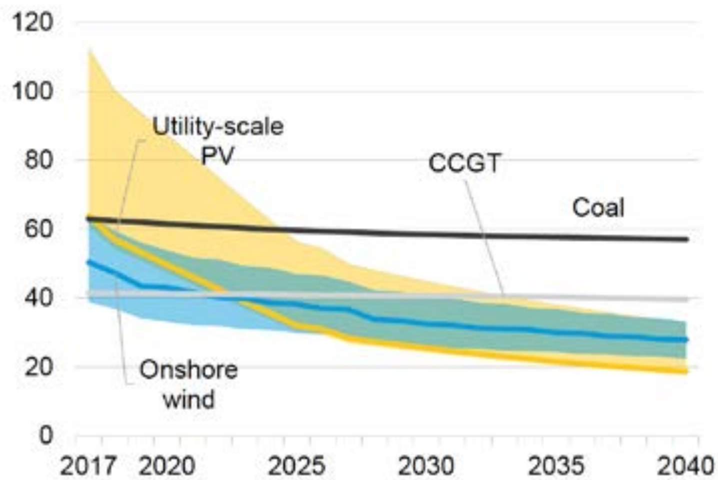
The costs of clean energy technologies have declined rapidly in the last decade. In some parts of the world, utility-scale wind or solar is the least costly generation option on a levelized cost of energy basis, even without incentives or subsidies (Figure 1).

Figure 1: Unsubsidized Levelized Cost of Energy

Source: Lazard (2017). Levelized Cost of Energy. Retrieved from: https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

In the US, Bloomberg New Energy Finance estimates that utility-scale solar and onshore wind are already cheaper than the cost to build a new coal resource, and we are likely to reach the same tipping point for combined cycle natural gas sometime in the early 2020s (Figure 2).

Figure 2. Dollars Per Megawatt-hour ($/MWh, real 2016 dollars) in the USA for Onshore Wind, Utility-Scale PV, Coal, and CCGT



Source: Liebreich, M. (2017, October 18). Trends in clean energy and transportation. CAISO Stakeholder Symposium, Sacramento, CA. Bloomberg New Energy Finance. Retrieved from: https://www.caiso.com/Documents/MichaelLiebreich_2017CaliforniaISO_StakeholderSymposium.pdf

Wind and solar developers are submitting winning bids in all-source competitive procurement tenders at prices even lower than those depicted in Figures 1 and 2, such as those recently completed in Saudi Arabia (1.79 cents/kWh for solar) and India (2.0 cents/kWh for wind).[6] In the U.S., where renewable energy tax incentives remain, Public Service Company of Colorado reported receiving *median* bids in December 2017 of just $30/MWh (3 cents/kWh) for solar and $18/MWh for wind.[7] Costs are also falling for systems that combine renewable energy with battery storage. In the same Colorado solicitation, the median bid for solar systems with battery storage was just 20 percent higher at $36/MWh. Not only are these prices competitive with traditional fossil-fueled generation options, they appear to have reached a point that was once considered unthinkable: the total levelized cost of renewable energy is in some cases less than the fuel costs of an average fossil generation unit (estimated by the U.S. Energy Information Administration to be $26/MWh for coal and $25/MWh for natural gas).[8] And the costs of renewables are expected to decline even further, likely offsetting the phase-out of tax incentives. This trend implies that new renewables could soon be a least cost resource to meet utility needs as well as a cost-saving option even for utilities that have no need for new generating capacity.

The capabilities of clean energy technologies are also improving even as costs decline. For example,

6 Bloomberg New Energy Finance (2017). New Energy Outlook 2017. Retrieved from: https://about.bnef.com/new-energy-outlook/

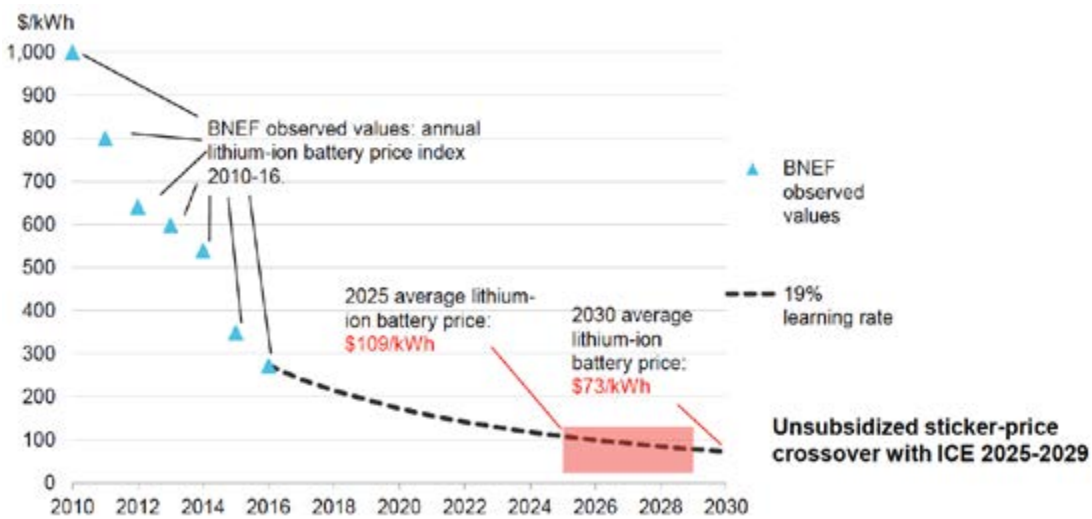
7 Xcel Energy (2017, December 28). 2016 Electric Resource Plan: 2017 All Source Solicitation 30-Day Report. Prepared for Public Service Company of Colorado. Retrieved from: https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html

8 U. S. Energy Information Administration. (2016). Electric Power Annual. Retrieved from: https://www.eia.gov/electricity/annual/. Existing Plant Average Fuel and O&M from USEIA Table 8.4.

wind turbines can now provide synthetic inertia. Smart inverters, when functionality is enabled, allow solar systems to ride through voltage deviations. Two-way electronic communications and smart electric meters enable home appliances to be used as demand response resources, shedding or shifting load as needed. Battery storage systems can provide more power for longer periods of time. In some cases, these advancements are in early stages but because the technologies are both capable and cost-effective, we expect their deployment to continue accelerating. All these developments are contributing to the ongoing transformation of the power sector.

The falling costs and improving capabilities of electric end-use technologies such as electric vehicles and heat pumps are related trends that have the potential to produce significant benefits for consumers and the environment (see "electrification," below). For example, BNEF projects that declining costs for lithium-ion EV battery packs will mean that EVs compete on an unsubsidized basis with traditional internal combustion engine vehicles sometime in the 2025-2029 timeframe (See Figure 3). This cost improvement is occurring at the same time that battery capabilities are improving such that EVs can drive farther on a single charge, and recharge faster.

Figure 3. Lithium-ion EV Battery Pack Prices, Historical and Forecast



Source: Bloomberg New Energy Finance (2017). New Energy Outlook 2017. Retrieved from: https://about.bnef.com/new-energy-outlook/ Note: prices are an average of BEV and PHEV batteries and include both cell and pack costs. Historical prices are nominal, future ones are in real 2016 US dollars.

Heat pumps have been used for decades to heat and cool homes in moderate climates, and recent technological advances have made them a cost-effective option even in cold climates. According to a recent National Renewable Energy Laboratory study, in places where electricity is being used to fuel space or water heating, the lifetime cost of heat pumps is already lower than traditional resistance-based technologies.[9] NREL also found that at current (or near future expected) cost and

9 Jadun, P., McMillan,C., Steinberg, D., Muratori, M., Vimmerstedt, L., and Mai, T. (2017). Electrification Futures Study: End-Use Electric

performance, heat pumps are approaching cost parity with incumbent natural gas technologies in moderate to warm climates.[10]

These trends are accelerating other changes, particularly the ability of greater numbers of customers to interact with the grid and control their energy use. Regulators are starting to consider how customers acting in a coordinated way can interact with the grid to promote public interest outcomes and avoid potentially detrimental effects such as increased costs or inequitable distribution of benefits. The pace of technological advancement and changes in customer desires are raising questions about whether state regulatory processes can adapt quickly enough.

Environmental Policy Drivers

A desire to achieve societal and environmental outcomes from the power sector is not as "new" of a trend as some of the others described here, but it remains a strong force that determines what resources utilities must acquire and what environmental controls must be in place. The first state-level renewable portfolio standard was created in Iowa in 1983.[11] As of 2018 29 states plus D.C. have some sort of resource-specific procurement standard and several states, including Oregon, California, New York and Hawaii, have increased the ambitiousness of their standards to include requirements for utilities to eventually source 50% or more of their energy from renewable resources.[12]

In addition to the widespread adoption of renewable standards, some states are pursuing greenhouse gas reduction goals, either on an economy-wide basis as in California, or on a sector-specific basis, as in the states of the Regional Greenhouse Gas Initiative. Even states that do not have a legally binding requirement to reduce carbon emissions are actively working to figure out how to meet non-binding reduction goals and asking what the power sector's role in that should be. For example, Oregon has long required its investor-owned utilities to analyze future scenarios that include a price on carbon emissions in integrated resource planning (IRP) as a way to estimate the riskiness of certain portfolios of resources. Across the country, stakeholders in utility regulatory processes are asking for a consideration of carbon emissions to be a determinant of decision-making.

These policy desires have been a major factor in driving installation of renewable energy and thus have contributed to the cost declines for these technologies through economies of scale and learning-by-doing. They have also raised questions for utilities and regulators. How much carbon reduction is technologically feasible for the power sector while maintaining affordability and reliability? Are we planning for the grid balancing challenges that come with increasing quantities of non-dispatchable generation? What is the role of the power sector in helping to decarbonize other sectors of the economy, and what is a fair and equitable way to pay for such a transition?

Technology Cost and Performance Projections through 2050. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70485. https://www.nrel.gov/docs/fy18osti/70485.pdf.

10 This NREL study observed that greater technology improvements are likely needed for heat pump adoption to make sense in cold climates, but also that this may not apply in regions with above average natural gas prices, or over months or in seasons with higher gas prices.

11 Center for Climate and Energy Solutions, State Policy Maps. Accessed from: https://www.c2es.org/content/state-climate-policy/

12 Center for Climate and Energy Solutions, State Policy Maps. Accessed from: https://www.c2es.org/content/state-climate-policy/

Should we be considering a more coordinated or streamlined approach to environmental and economic regulation? What is the role of utilities and regulators to harness the changes underway in the power sector to address environmental justice concerns?

Electrification

Electrification of energy end uses is another trend contributing to power sector transformation that is closely tied to the others discussed thus far in this paper. Electric energy can fuel vehicles and heat water and buildings as a substitute for gasoline, diesel fuel, propane, and natural gas. The trend toward electrification of energy end uses appears to be driven by a desire to achieve one or more of the following beneficial outcomes: saving consumers money on their energy use, more flexible resources on the grid to assist with grid balancing and ease the integration of greater penetrations of variable renewable energy, and to aid in reducing air emissions - primarily carbon – in states where this is a policy driver.

As discussed briefly in Section 2, consumers have a growing number of choices when it comes to energy uses, and are beginning to realize the potential for cost savings from switching to electric end uses. For example, the greater overall efficiency of electric vehicles (i.e. less total energy used to produce the same number of miles driven) compared to conventional vehicles means that consumers who switch can see their total energy costs go down. In a simple illustration, consider someone who paid $50 last month for gasoline and $50 for electricity (a total of $100). If this customer switches to an EV, they may have no gasoline bill for

SIDEBAR

It's Not Just About Load Growth

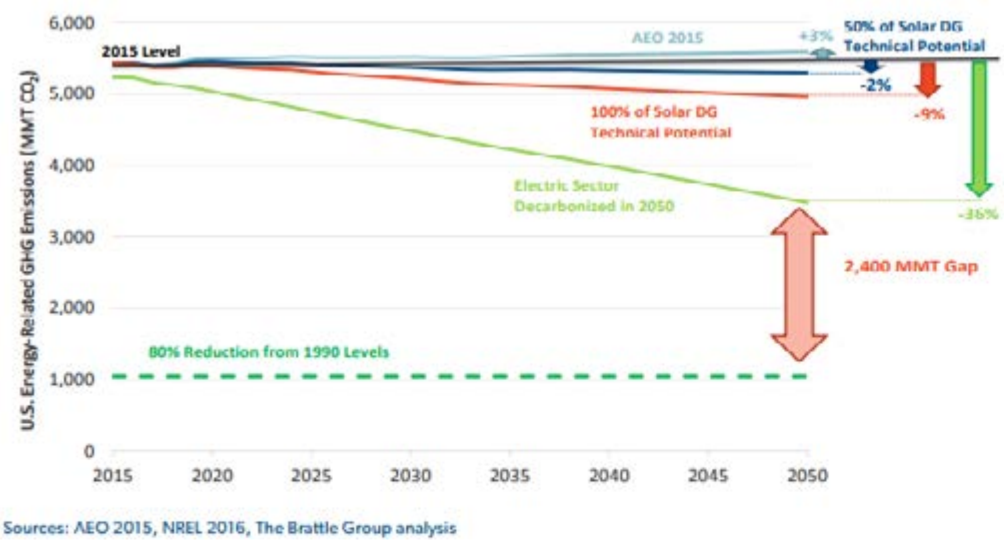
Electrification is viewed by some as an opportunity for utilities to begin addressing another widely-recognized trend: flat or declining load. The traditional regulatory model is such that utilities make profit for their shareholders by investing capital in physical assets (known as the "Averch-Johnson" effect) and by selling more units of energy (known as the "throughput incentive"). Under this model, flat or declining load is a major threat to the utility's business model – hence the interest in electrification as a strategy to reverse that trend. In contrast, RAP believes that, while electrification does present opportunities for utilities (primarily through the provision of new services to customers), a focus on load growth risks not achieving the significant benefits that are possible through *beneficial* electrification. In addition, RAP has long been a proponent of decoupling utilities' recovery of their revenue requirement from the quantity of electricity that they sell, in an effort to make utilities indifferent to sales volume and remove inherent opposition to conservation. Such an approach can help states ensure that as utilities propose electrification initiatives they are not being given an incentive to promote measures just for the purpose of growing load.

For a more detailed discussion of the traditional regulatory model and decoupling, please refer to an earlier RAP paper, *Basics of Traditional Utility Regulation and Oregon Context,* here: http://www.puc.state.or.us/Renewable%20Energy/Oregon_978_framingpaper_rap_feb_16.pdf the month but an $80 electricity bill. The $20 difference reflects an overall reduction in energy cost despite the increase in electricity consumption. [13]

Increased deployment of electric vehicles, water heaters, and heat pumps has the potential to add to electric energy consumption. However, there is a growing understanding of the fact that these new electric loads are flexible and therefore can be managed as grid resources. For example, with enabling technology and the right price signals, electric vehicles can be charged during off-peak hours when clean energy might otherwise have to be curtailed. Charging demands can be adjusted to provide ancillary services to the grid, and as technology improves EVs may even be able to discharge energy from their batteries to meet system needs. The timing of water heating and space heating can be controlled for similar purposes. For example, when connected to control technology, a heat pump can help manage system demand by preheating water during overnight hours and running less during the early evening peak. Utilities and regulators across the country are exploring how increased electric energy consumption can benefit the grid and require only minor increases to capacity needs.

Additionally, there is a growing acceptance of the importance of electrification to any realistic plan for deep decarbonization of the U.S. economy. For example, a recent Brattle Group study illustrated how achieving an 80 percent reduction in greenhouse gas (GHG) emissions by 2050 is not possible by simply reducing power sector emissions (Figure 4).[14]

Figure 4. U.S. Energy-Related GHG Emissions with Fully Decarbonized Electric Power Sector in 2050



[13] Farnsworth, D., and Shipley, J. (forthcoming). Beneficial Electrification Principles. Montpelier, VT: The Regulatory Assistance Project.

14 Weiss, J., Hledik, R., Hagerty, M., Gorman, W. (2017, January). Electrification: Emerging Opportunities for Utility Growth. Cambridge, MA: The Brattle Group. Retrieved from: http://www.brattle.com/system/news/pdfs/000/001/174/original/Electrification_Whitepaper_Final_Single_Pages.pdf?1485532518.

Rather, additional emission reductions will be needed from other sectors like transportation and water and space heating. Beneficial electrification can contribute to the decarbonization of these other sectors because as the grid gets cleaner over time, electrified end-uses will also get cleaner relative to their fossil fuel-powered alternatives. As renewable energy gets less expensive and more abundant, electric power becomes a more affordable and less polluting option than fossil fuels for these energy end uses. Indeed, a significant number of analyses of pathways to a fully decarbonized economy conclude that a sustained transition from our existing energy supply and demand infrastructure to more efficient, electric, low-carbon equipment is needed.

Today, in Oregon, less than one percent of currently registered vehicles are electric or plug-in hybrid vehicles.[15] According to the Northwest Energy Efficiency Alliance, in single family Oregon homes about one half of the installed water heaters are electric and one-third rely on electric heat, though most of those homes use inefficient baseboard heaters and efficient electric heat pumps are less common.[16] However, customers are increasingly opting for electric vehicles and heat pumps. Bloomberg New Energy Finance projects that over 50 percent of new U.S. passenger vehicles in 2040 will be electric.[17] Sales of electric heat pumps in the U.S. are growing as advances in technology make them more affordable, more efficient and more capable of functioning in cold climates.[18] And a small but growing number of controllable, grid-integrated water heaters have been installed in the U.S., including a 600-customer pilot program sponsored by the Bonneville Power Administration.[19]

The trend toward electrification and a desire to capture its potential benefits is inspiring questions among utilities, regulators and stakeholders. Are flexible sources of electricity demand properly valued by utilities, and do customers have opportunities to provide value to the grid through their use of electrified devices? Do we have a strong enough understanding of the likely impacts on load shape under various possible adoption scenarios? Given the limited number of opportunities to replace technologies at their natural replacement points, what policies and programs need to be in place to transition energy infrastructure? Is there a danger of locking in the use of less flexible, more costly, and higher emitting technologies, and how can this be avoided? Does rate design motivate customers to buy and use electric devices in ways that more fully utilize utility assets? How can we ensure that the benefits of electrification are equitably shared and are accessible by low income households and disadvantaged communities?

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[15] Oregon Department of Motor Vehicles (2017). Vehicle Registration Statistics. Retrieved from: http://www.oregon.gov/ODOT/DMV/Pages/News/vehicle_stats.aspx

[16] Northwest Energy Efficiency Alliance (2017). Residential Building Stock Assessment II, Single Family Homes Report 2016-2017. Retrieved from: http://neea.org/resource-center/regional-data-resources

[17] Bloomberg New Energy Finance (2017). Electric Vehicle Outlook 2017. Retrieved from: https://about.bnef.com/electric-vehicle-outlook/

[18] Vermont Energy Investment Corporation (2018) Driving the Heat Pump Market: Lessons Learned from the Northeast. Retrieved from: https://www.veic.org/event-calendar/archive/2018/02/21/default-calendar/driving-the-heat-pump-market-lessons-learned-from-the-northeast-

[19] Bonneville Power Administration. (undated). Smart Water Heater Pilot. Retrieved from: https://www.bpa.gov/EE/Technology/EE-emerging-technologies/Projects-Reports-Archives/Field-Tests/Pages/Smart-Water-Heater-Pilot.aspx

Distributed Energy Resources and Their Impact on the Distribution System

Distributed energy resources (DERs) are assuming an increasing role in meeting energy and energy service needs on the electric system. Distribution planning has historically presumed passive customers who, at their most sophisticated, are participating in energy efficiency and demand response programs. Distribution planning has also historically presumed analog control systems and the absence of real time information. Improved distribution system technologies now include information, communications and digital control technologies which can support operations in a day-ahead, hourly, or intra-hourly time frame.

Distribution planning tools and rules of thumb have begun to evolve to accommodate these changing needs. Some states have begun to set out a vision for a distribution system that can serve as a platform that enables active customers, aggregators and utility system operators. There is a growing recognition that investment in the distribution system will likely be required to physically handle increasing volumes of two-way transactions and to track and convey system conditions and capabilities. Hosting capacity limits at the level of the distribution feeder can be analyzed both to communicate to customers and vendors where opportunities lie for further DER development, but also to convey where distribution system congestion is likely to require either utility infrastructure investment or targeted DER deployment to relieve congestion. The amount of additional or modified physical infrastructure required on the distribution system is difficult to assess absent good information on current system conditions.

These trends raise a number of questions for utilities and regulators. For example, are the existing information, communications and electric system control technologies capable of informing decisions about investments in the physical distribution system? Should physical infrastructure upgrades be deferred until real-time system conditions and DER service capabilities are recognized in operations and planning practices? What initial steps should be taken to make real-time conditions and DER service capabilities more transparent to utility system actors?[20]

Changes in Bulk Electricity Markets

Bulk electric systems are also changing with increasing opportunities to buy, sell and share regional resources to meet utility customer needs. Regional exchange on a seasonal and long-term basis is an established practice in the Northwest where regional direct current lines and the California Oregon Intertie have been providing benefits for decades. More recently, the Western Energy Imbalance Market (Western EIM) has introduced opportunities to market regional resources on the intra-hour time frame. Other regional exchange opportunities are being contemplated with the announced expansion of the Western EIM products to include a proposed day ahead opportunity. Regional resource sharing mechanisms are also being explored among the coastal states. In the

20 Readers interested in further information about distribution system planning may find the following DOE report useful: Di Martini, P., and Kristov, L. (2015). Distribution Systems in a High Distributed Energy Resources Future. Ed. Lisa C Schwartz. Berkley, CA: Lawrence Berkley National Laboratory. Retrieved from: http://eta-publications.lbl.gov/sites/default/files/lbnl-1003797.pdf

western interconnection more broadly, MWTG (Mountain West Transmission Group) is exploring a relationship with the Southwest Power Pool (SPP) that may result market opportunities and the PEAK Reliability Organization has announced a collaborative venture with PJM to offer services as well. Regardless of how these efforts move forward, it is safe to say that markets and regional resource sharing opportunities will be expanding in the Western U.S. in the coming decade.

A consequence of regional exchange and regional markets is an increased opportunity for regional resources to meet local needs. This has implications for integrated resource planning in states with investor owned utilities which may increasingly reflect the presence of regional resources. Taken together, the emergence of DERs and of available resources on the bulk electric system imply that planning processes will increase in importance. For example, forecasting the needs of customers on the distribution system will be affected by the availability of DERs. Similarly, evaluating new proposed supply operations will be impacted by available DERs that can be aggregated to provide grid services and already-available regional resources. Distribution and transmission infrastructure proposals will increasingly be evaluated in light of these local and regional opportunities as well.

Whether existing information, communication and control systems of utilities are adequate will be a key question to ask as planning processes become more complex and consider a wider range of potential options. Do regulators, utilities, and stakeholders have the tools they need to better inform IRP proposals as available grid resources undergo significant changes?

Evolving Approaches to Utility Regulation

One of the challenges for regulators everywhere is to adapt regulation accordingly as customer needs, technology, and policies change as the trends in this paper describe. One of the results of the trends and drivers discussed thus far is that, to meet societal goals, such as the desire to reduce the climate impacts of the power system, some jurisdictions are experimenting with different types of regulatory models. In particular, states are exploring options for changing the traditional revenue model of utilities to better align profit incentives with societal outcomes. Namely, replacing the traditional cost of service/rate of return regulatory model, which primarily rewards utilities for making capital investments, with a regulatory model that makes the outcomes that society most desires the ones that are most profitable for the utility.

This so-called “Performance-Based Regulation (PBR)” represents a significant modification to historic cost-of-service utility regulation paradigms, wherein performance incentives can operate as an incremental add-on to traditional regulation to align utility planning, investments, and operations with public policies and societal goals.[21] PBR provides a regulatory framework to connect goals, targets, and measures to utility performance or executive compensation. Utility revenue and shareholder earnings can be based – entirely or in part – on specific performance

21 For more information on PBR, see: Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

And: Littell, D, et al. (2017). Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. Golden, CO: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf metrics and other non-investment factors, such as providing low-cost service and being responsive to government mandates. PBR can strengthen the incentives of utilities to perform in desired ways.

The best-known example of a transition to a comprehensive PBR model comes from the United Kingdom (UK). In 2013, the UK regulator (OFGEM) implemented a new approach called RIIO: Revenues = Incentives + Innovation + Outputs. RIIO represents a transition away from the traditional approach of simply rewarding investment in infrastructure to an outcome-based approach, where revenue-based regulation is complemented with a system of financial rewards for achievement of specified goals developed with public input. Utilities can increase their earnings by meeting pre-determined targets for customer satisfaction, network safety, network reliability, new connections, environmental impact, and social obligations.

Although no U.S. state has implemented a regulatory approach entirely comparable to the UK's RIIO, New York's Public Service Commission is clearly moving in that direction. Through its "Reforming the Energy Vision" or NY REV initiative, the Commission is adopting a form of PBR that provides for several outcome-based incentives to be implemented. One innovative approach that New York is taking is around DER deployment. The Commission recognized that establishment of a 'baseline' level of predicted DER deployment is difficult, and thus simply tracking interconnection requests and utilities' response timeliness may not provide an adequate way to evaluate the quality of the DER interconnection process. Instead, the Commission focused its incentive for DER on a survey of DER providers, which is meant to assess how well utilities are working with developers and identify targeted locations on the grid where DER may have a high value.[22]

Numerous U.S. jurisdictions have used a limited form of PBR to motivate adoption of energy efficiency goals and satisfaction of targets and metrics. For example, at least 26 U.S. states have used performance incentives to overcome the utility "throughput incentive" and encourage energy efficiency deployments. Over time, energy efficiency program performance improved markedly in states offering these incentives.[23]

As part of a grid modernization initiative, the Illinois Commerce Commission adopted a PBR formula rate tariff with the stated goal of achieving increased grid reliability and operational efficiency. Utilities were given increased certainty that grid modernization expenses would be found prudent with a set rate of return. In exchange for this formula rate treatment, participating utilities are required to file multi-year metrics (including reliability performance) with the Commission to improve performance over a 10-year period. So far, the utilities have reported improvements in outage frequency and duration, but they have failed to meet the 75% improvement performance criteria and have been penalized with a 5-basis point reduction in authorized return-on-equity as a result. This is an example of a negative incentive scheme which imposes a relatively low penalty in

[22] Littell, D, et al. (2017). Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. Golden, CO: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf

23 EE performance incentives are noted here as an example of limited PBR that is widespread. In states like Oregon where a third party administers EE programs, the administrator (e.g., ETO) doesn't have a throughput incentive and this particular type of performance incentive usually isn't appropriate for utilities.

an approved formulate rate when reliability criteria are not met.[24]

There are many examples of performance incentive mechanisms from around the world that can provide lessons to jurisdictions considering such modifications to the regulatory paradigm.[25] One clear lesson is that an important first step in creating a PBR mechanism is to identify, articulate, and prioritize policy goals, and then to understand how well or poorly the existing regulatory structure meets those goals under a 'business-as-usual' scenario. Some key questions may be: What outcomes do customers and the broader public want to see pursued by utilities? How well does the existing regulatory framework do at promoting those outcomes? Is it possible to design a mechanism to promote new objectives or goals?

Conclusion

This paper has attempted to examine and summarize some of the major trends that are beginning to impact the power sector now and are likely to continue to do so in the future. We have raised many questions about these trends and their implications, with the objective of providing fodder for discussion in Oregon. Not all of these questions need to be addressed at once, or even at all. Oregon stakeholders and policymakers should decide what is most important and relevant to the next steps they wish to take.

[24] Littell, D, et al. (2017). Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. Golden, CO: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf

25 For more information on lessons learned from PBR mechanisms around the world, readers are encouraged to see Chapter 7 of: Littell, D, et al. (2017). Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. Golden, CO: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf

APPENDIX E: GROUP MEMOS FROM SB 978 PROCESS

Appendix E-1 Low Carbon Future Group

SB 978 Low-Carbon Future Group Memo to Oregon PUC May 2018

1. ***How can the regulated utility sector contribute to the transition to a low-carbon future?***
2. ***What is the role of regulators in decarbonization?***

1. Relevant policy tensions in Oregon: Urgent action is necessary to prevent catastrophic climate change. To mitigate Oregon's climate impacts and achieve our greenhouse gas (GHG) reduction goal (currently 75% below 1990 levels by 2050), Oregon must rapidly decarbonize its energy sector. However, **four key policy tensions** constrain Oregon's transition to a low-carbon future. **First,** Oregon lacks legislative mandates to reduce GHG emissions and decarbonize our economy. The PUC and other agencies lack clear authority and directives to adopt mandatory carbon regulations, and there is no inter-agency framework in place to ensure coordination between state agencies. **Second**, Oregon has disproportionately focused on reducing emissions from the regulated utility sectors, while allowing emissions to increase in other sectors (most notably, transportation). An economy-wide mitigation regime is necessary to meet Oregon's GHG reduction targets, yet the existing utility regulatory framework and mechanisms present barriers and imbalances for regulators (and utilities) when trying to identify and implement optimal solutions both inside and across sectors.[1] **Third**, the current regulatory process may be too cumbersome to act quickly. Innovation and flexibility will be necessary to effectively and swiftly transition Oregon's regulated energy sector away from fossil fuels. Regulators must have latitude to allow those entities charged with meeting the state's GHG goals to deploy new low-carbon technologies, practices, and other mechanisms, while also preserving market access for competitive resources. And **fourth**, the transition to a decarbonized energy system may impose additional costs on vulnerable populations. However, vulnerable frontline communities (e.g. low-income, communities of color, immigrants) are also at greater risk of harm from the impacts of climate change, and many experts estimate the cost of doing nothing to be much greater than the costs of the clean energy transition. Oregon's regulatory frameworks must therefore aim to minimize disparate impacts while also facilitating a rapid transition to a low-carbon future.

2. Policy or regulatory actions Oregon should consider in responding to these tensions: To effectively decarbonize its energy system, Oregon must accomplish three overarching objectives: 1) maximize energy efficiency and conservation to reduce electricity and gas load, 2) transition from fossil fuels to renewable energy resources, and 3) decarbonize the transportation sector and other carbon-intensive sectors and end-uses. Moreover, Oregon must achieve these objectives as equitably, cost effectively, and quickly as possible.

Policy mechanisms to help achieve decarbonization objectives:

- ***Adopt carbon mandates*:** Adopt a legislative directive to decarbonize that includes economy-wide caps on GHG emissions and a mandate to achieve Oregon's GHG reduction goals by 2050. The directive should enable accurate carbon accounting and mechanisms to adjust caps downward or between sectors as markets or loads shift over time.
- ***Align the PUC's mission with Oregon's climate goals*:** Legislatively expand the PUC's regulatory authority to achieve the energy sector's evolving proportionate share of the state's GHG reduction goals by revising the PUC's mission/mandate and explicitly acknowledging its role in a low-carbon future.
- ***Prevent Additional Emissions Lock-In*:** Ensure the construction of any new or expanded large-scale fossil fuel infrastructure does not result in a net increase of GHG emissions, is consistent with a pathway to compliance with Oregon's GHG goals,[2] and incorporates the social cost of carbon into resource planning and procurement decisions.
- ***Align utility incentives with Oregon's GHG reduction goals*:** Evaluate and adopt performance-based ratemaking (PBR) mechanisms that can incentivize utilities to achieve policy objectives, reduce GHG emissions, and make investments in decarbonization.[3] Assess carbon intensity, costs, and impacts of lifecycle methane emissions using both short- and long-term global warming potentials and promote best practices in gas production as a way to improve sectoral emissions beyond state's borders.
- ***Increase system-wide efficiencies through regional grid management and energy markets*:**
  - Improve coordination across the West to enable large-scale development and integration of renewable resources. Evaluate a broader organized electricity market to ensure it benefits Oregon consumers and the environment.

[1] For example, policy development in the natural gas sector has lagged behind the electric sector in terms of driving GHG reductions. While the electric sector has sweeping policies that favor renewable generation (e.g., RPS), gas utilities are required to purchase the least cost/least risk resources, even if lower carbon options may be better for customers from a societal perspective.
[2] There is some disagreement among group members regarding the scope of such a consideration/prohibition. Some members prefer a total ban on investments in new fossil fuel infrastructure, while others note that some investments should be permitted if new infrastructure would benefit consumers and would not create a net increase in GHG emissions.
[3] PBR design elements to evaluate include performance metrics and targets and financial incentives, such a conditional rate of return, incentives for EV deployment, etc.

  - Increase grid-level efficiency through improved regional coordination, including through cross-jurisdictional IRP and transmission planning processes focused on regional resources and needs.[4]
  - Increase energy storage to meet short-term and seasonal needs, assist with grid management, and help integrate renewable energy. Explore strategies such as energy storage sited at transmission and distribution substations, customer-sited energy storage, power-to-gas, and pumped hydropower energy storage.[5]
  - Eliminate barriers to competitive markets to drive down renewable energy costs and reduce GHG emissions while ensuring all providers comply with Oregon's GHG reduction targets.
  - Examine the need for streamlined permitting for renewable energy and transmission facilities, while also balancing land use and species impacts from facilities sited in critical habitat.
  - Improve distribution planning and demand response; include price signals as a demand response tool.
- ***Transition to renewable energy and decarbonize the energy sector*:**
  - Avoid the need for new fossil gas generation resources by deploying renewable energy, energy storage, energy efficiency, and demand response to meet expected growing electricity loads.
  - Revise IRP process/guidelines to better address portfolios' carbon risks and drive utilities' emissions reductions to be consistent with Oregon's current and future carbon policies.[6]
  - Consider expanding customer choice options, including utility green tariff and/or direct access programs for industrial/commercial customers and community choice aggregation for counties or municipalities wanting to purchase 100% renewables, consistent with equity principles and consideration of impacts on all customers.
  - Build or more efficiently use transmission and storage assets to access and integrate more renewable power.
  - Implement and enforce existing policies (e.g. state PURPA regulations, community-based renewable energy goals, net metering) to support existing small-scale renewable generators and promote renewable energy deployment.
- ***Maximize energy efficiency and conservation at the distribution level*:**
  - Acknowledge that PUC cost effectiveness tests for energy efficiency constrains demand-side management investments and limits the availability of Energy Trust efficiency incentives.
  - Develop mechanisms to maximize energy efficiency in homes and buildings. Energy labeling and certification (such as Earth Advantage and other systems) increase awareness of energy use. State legislation should mandate Home Energy Score communication to buyers and allowance in financing.
  - Examine and possibly adjust the cost effectiveness methodology to enable investments in distributed energy resources (DER) (demand response, EVs, fuel cells, solar DG, CHP, storage); consider resilience value of DERs.
- ***Decarbonize the transportation sector by transitioning to zero-emissions vehicles*:**
  - Quantify the value transportation electrification provides to the electric grid[7] and to meeting the state's overall climate goals. Define EV deployment as a benefit to the system, rather than a cost. Develop a valuation methodology to determine the prudence of utility transportation electrification programs.
  - Develop mechanisms to incentivize deployment of EV charging infrastructure (including personal, multi-family, and workplace EV charging).[8]
  - Focus electrification in areas where large emissions reductions are possible and energy can be used off-peak—such as passenger vehicle electrification. Require and/or incentivize non-new heavy duty vehicles to convert from diesel to cleaner fuels, such as RNG or biodiesel, with signifiantly lower PM, NOx, and GHG emissions.
  - Develop strategies to ensure that autonomous vehicles registered in Oregon are EVs.
- ***Promote a Just Transition*:** Consider new tools, such as income-differentiated rate structures or metrics to evaluate total energy burdens, to address the inequitable impacts of deep decarbonization.
- ***Analyze and Evaluate*:** Conduct an integrated, quantitative evaluation of different pathways to deep decarbonization of the Oregon and regional energy sectors that takes into account regional renewable energy resources, beneficial electrification of transportation and other sectors, equity considerations, land use impacts, resiliency, and any associated trade-offs. The legislature should clearly delineate agency roles and create an inter-agency task force to explore cross-sectoral strategies and opportunities to coordinate regulatory activities to further decarbonize all carbon-intensive economic sectors.

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[4] For example, CA's SB 350 (2015) directed the Cal. PUC (IOUs) and CEC (COUs) to develop new IRP processes for IOUs/COUs and empowered state regulators to evaluate the optimal role of an expanded electric sector in meeting the state's economy-wide GHG targets.
[5] Batteries and pumped storage will be important components of our future storage system, but because the PNW is a winter peaking region, our more critical need will be seasonal storage (i.e., to move abundant renewable energy from the spring and summer to when it is needed in the winter). Power-to-gas (P2G) uses excess renewable energy to make hydrogen, which can be stored for future use.
[6] For example, the Washington UTC recently directed regulated investor-owned utilities to integrate the social cost of carbon into their long-term planning and investment decisions.
[7] Including decarbonization, operational benefits, and whole-home energy costs.
[8] The Oregon legislature and the PUC (along with ODOE and BCD) should advocate for best practices in building code improvements to increase energy efficiency, distributed generation, and EV charging.

Appendix E-2 Economic Efficiency Group

Economic Efficiency: Do our existing incentives lead to the most economically efficient outcomes? If not, how do we incentivize the most economically efficient outcomes?[1] [2]

1-2. *Briefly describe the nature of this policy tension/question - What is happening? To what extent does this policy tension exist in Oregon, if so, why is it relevant to the state?*

Investor owned electric utilities (IOUs) are generally subject to traditional ratemaking that allows a *return on and of* capital investments but only a *return of* other expenses. IOUs have traditionally been economically regulated as they have been considered natural monopolies due to being capital intensive and the need to avoid inefficiencies of duplication of distribution and transmission service. Natural monopoly distribution and transmission services can create efficiencies and increase reliability, system affordability, access to the system, potential for equitable outcomes, safety, and allow investors to attract capital. Regulation sought to ensure just and reasonable prices and services and to ensure that investments are prudent and least-cost/least-risk to customers. However, electric generation is no longer a natural monopoly. Changes in technology, increased customer interest, the transition to renewable energy, market innovations, and electric generation competition are challenging the monopoly status of IOUs and the traditional regulatory model.

Traditional utility ratemaking established rates that allows IOUs an opportunity to earn a return on capital investments – including a return commensurate with the returns of similarly situated businesses. This provides an economic incentive to own large capital assets, including electric generation. The electricity sector continues to be capital intensive and there is robust competition to attract investor funds (both debt and equity). Failure to recover substantial incurred costs can harm the financial health of utilities, which provides a check on OPUC disallowances. In addition, IOUs are only able to earn a return on assets that are used and useful to serve customers, which protects against over investment by IOUs and limits the ability to conduct research and development. The time between a utility's last approved rate increase and the next approved rate increase (or "regulatory lag") can incent a utility to reduce costs and obtain efficiencies that increase earnings between rate cases and ultimately lower future rates. IOUs are generally risk averse and do not innovate as much as firms operating in a competitive market, which is reflected in their authorized rate of return. IOUs generally hold onto assets until they are fully depreciated, which may limit their ability to divest or shut down uneconomic investments. The need to sell increased throughput provided a disincentive to invest in conservation, which has been addressed with decoupling and the creation of the Energy Trust of Oregon.

Regulation of IOUs' generation function historically relied upon an OPUC regulatory or command and control approach (carrots and sticks), rather than a market approach, to achieve state and federal goals related to power supply, environmental and climate goals, equity, reliability, accessibility and affordability. Utility competitors (non-IOU generation owners, electric vehicle charging companies, etc.) do not have the same OPUC mandated regulatory incentives for cost controls that IOUs have, but are instead subject to market competition for price and quality. COUs with owned generation are subject to the regulation and ratemaking authority of their local governing authorities. Both IOU and non-IOU owners and participants can be subject to both OPUC and non-OPUC regulations to achieve state and federal goals.

Most of the load in Oregon is served by IOUs, but about 35 percent Oregon's load, and 25 percent of Oregon's customers, is served by COUs and many of these policy tensions do not exist because the existing COUs buy most of their power from the low cost, low carbon Federal Columbia River Power System, are exempt from many of the legislative mandates and policies for IOUs, and do not have the same economic incentives.

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1 Some stakeholders disagreed with the name and definition for this group arguing that it should include innovation, competition, economic development, and other issues beyond the vision of the Commission as an economic regulator. Bullet points represent the comments of one or more individual participants, and may not be unanimous positions or viewpoints.

2 Group participants included: Silvia Tanner (Renewable Northwest), Jay Tinker (Portland General Electric Company), Scott Bolton (Pacific Power), Irion Sanger (Northwest and Intermountain Power Producers Coalition), Crystal Ball (Bonneville Power Administration), Marc Hellman (Alliance of Western Energy Consumers), Diane Henkels (Small Business Utility Advocates), Jennifer Joly (Oregon Municipal Electric Utilities Association), Alan Hickenbottom (Latitude45 Associates), Rebecca Langer (Oregon State University), Leah Gibbs (citizen), Will Gehrke (Citizens' Utility Board), Angus Duncan (Bonneville Environmental Foundation), and Kyle Walker (NW Natural).

3. *What policy or regulatory action might be required to address the tradeoffs you see?*

A range of policy and regulatory actions could address the tradeoffs, some which include: 1) divestiture of all IOU generation, barring IOUs from owning new generation absent unique opportunity or reliability need, or minimum percentage of new power purchased rather than owned; 2) facilitating the formation of an independent system operator to manage transmission and balancing; 3) expansion of customer choice through increased direct access, self-generation, net metering, and Community Choice Aggregation; 4) utility compensation through performance based ratemaking for managing the distribution and transmission grid, reducing environmental impacts, modernization, reliability, returns on power purchase agreements, etc; 5) utilities could be allowed to recover capital investments that are not presently used and useful to encourage longer-run forms of planning such as distribution expansion planning or renewable site acquisition; 6) COU formation and takeover of IOU service territory, but this is unlikely because new COUs would be subject to severe statutory impediments; 7) re-examination of consumer classes and rates, including but not limited to time of use rates, changing from marginal to embedded cost rate spread and design, demand charges, different retail rates for net metered or self-generation consumers, etc.; and 8) Public Utility Regulatory Policies Act reforms to increase or decrease the marketability of qualifying facilities.

4. *How are people in other places responding to this tension? Do they seem feasible in Oregon?*

Some responses include: 1) continued use of regulated IOUs to obtain public policy goals, sometimes with performance-based ratemaking, decoupling, increasing competition and/or customer choice; 2) deregulation through net metering, direct access, divestiture and/or limitations on IOU ownership of generation and transportation electrification; 3) increased regulation of market-based entities performing utility functions; and/or 4) formation of regional transmission organizations and independent system operators. New COUs formation is not occurring due to statutory obstacles.

5. *Are there ways you think Oregon should consider responding to this tension?*

There is agreement that the OPUC would retain some regulatory responsibilities, and that, to the extent applicable, state policy objectives should have to be met regardless of the type of market participants (IOUs, community choice aggregation, independent power producers, distributed generation, non-utility transportation electrification owners, new consumer owned utilities (COUs - electric coops, Peoples' Utility Districts, or municipals), etc.). There is also agreement that a western US independent system operator for day ahead and intra hour rebalancing would improve economic efficiency in energy resource operations.

There is debate about whether the current regulatory model is sufficient to meet the state's energy policy goals. Should generation remain a component of the regulated business model based on the assumption that generation, along with delivery, because it is affected with a public interest and that end-use consumer reliability is equally impacted by distribution and transmission reliability, and generation supply? Or are vertically integrated utilities and OPUC regulation making it more difficult to meet state goals, and can competition and non-utility market participants do so with less risk, lower costs and more innovative products?

Overlaying this debate are the unique opportunities and threats of climate change and technological innovation. Decarbonization is not merely another state policy goal, but is an existential threat to the traditional energy industry, business model and regulation. The regulatory structure can help, obstruct or allow innovation, or be overwhelmed by it. Thus, technological change can moot many of the electric industry regulatory debates as it did for the telecommunications industry.

There are three main options to respond to the tensions and harness and provide the right incentives for the electric industry as a whole to meet the state's energy goals. It is unclear as to whether we have the luxury to choose a path or if economic and technological changes will transform the market regardless.

Continuing the regulatory model of the past with incremental changes or tweaks like revisiting rate classes, depreciation rates, performance based ratemaking, etc.

Immediately adopt fundamental changes in the regulatory compact and utility business model by providing the utilities different economic incentives, removing them from owning generation assets, and allowing customers choice while protecting state goals including affordability for all, reliability and equity.

At a minimum, the SB 978 conversation should continue by identifying the complete list of the state's energy policy goals and the options to achieve them. At best, the OPUC should propose its vision for what direction the PUC views as the best way forward to meet the state energy policy goals.

Appendix E-3 Customer Choice Group

Customer Choice Group
(Wendy Gerlitz, Mike Goetz, Tyler Pepple, Tim Lynch, Sidney Villanueva, Amina Moreau, Ajay Kumar, Rebecca Smith, Loretta Mabinton)

1. Briefly describe the nature of this policy tension/question – What is happening?

Before addressing the policy tensions related to customer choice, it is important to note that "customer choice" can mean different things to different classes of customers in terms of the purchase and consumption of energy and energy services. Broadly, "customer choice" can be divided into two buckets:

i. The ability of customers to select different offerings from their incumbent utility (like a "green tariff" or a time-of-use rate, receiving 100% renewable power through their utility, or increased demand response options); and

ii. The ability of customers to select offerings independent of their incumbent utility (like 100% renewable power, direct access, community choice aggregation, or rooftop solar).

In either case, a similar policy tension exists, which is that expansion of customer options necessarily impacts customers who do not, or cannot, avail themselves of those options. These impacts may take the form of cost-shifting, reliability/provider of last resort obligations, and consumer protection.

2. To what extent does this policy tension exist in Oregon, if so, why is it relevant to the state?

Policy tensions associated with customer choice exist in Oregon and are relevant because certain customers want some choice, the State has certain policies in Oregon statutes (for example SB 1149 -the state's direct access law), and the utilities' have provider of last resort obligations. At the same time, residential customers are exploring demand-side options to individually tailor their electric service to their needs. Oregon has been faced with these policy tensions for nearly two decades, including ongoing debates over whether transition adjustments for direct access customers are too high or not high enough. Parties disagree as to whether the current system adequately includes customer choice (both through direct access and, through alternative utility offerings like demand response and residential pricing pilot programs) or adequately recognizes electricity as a basic necessity that should be made available to all in society, the role of investor owned utilities in providing safe, reliable service to all customers and their obligation to buy from qualifying facilities.

Technological innovations continue to advance the potential for customers to control where their electricity comes from and when they use electricity, even when it comes from the utility. However, while some customers may be able to pay the costs of new technology, the customers least able to pay may be the customers that end up with the fewest options and the least equitable and economic outcomes. Both utility options and retail choice could allow customers to prefer environmental over economic considerations, or vice versa, and enable customers to better control their exposure to future uncertainty.

3. What policy or regulatory action might be required to address the tradeoffs you see?

The Customer Choice Group had some conversation around each option suggested, but did not reach any consensus around desirable policy options.

- Expand existing utility customer choice options through tariff or non-tariff options.
- Expand direct access programs while ensuring (1) sufficient protections against cost-shifting and (2) the utility's continued ability to meet its reliability, grid modernization and provider of last resort obligations.
- Eliminate disincentives for demand-side resources in order to promote greater development and penetration of customer-directed energy options and potentially expand decoupling.
- Proactively use performance-based ratemaking mechanisms to allow more customer feedback and enable utilities to explore a variety of demand-side resources.

[009610.004/349696/3] 009610.004/349696/2

- Improve the current existing regulatory system (universal access) to enable utilities to innovate, add new programs that involve new technologies such as EVs or new statewide programs such as community solar. This could include pilot programs considering R&D 'used and useful', etc.
  Balance the need to innovate with the reality that the early phases of innovation are often not a least cost alternative.
- Community choice aggregation - Could be based on a geographic community or a "community" of like-minded customers regardless of geography (similar to a credit union).
  - Should address recovery of stranded prudent utility investments, include consumer protection laws, address concerns about the feasibility of moving to restructuring or deregulation without entry into a RTO/ISO, and address concerns about shifting the costs for future system upgrades and modernization.
- Restructuring/deregulation
  - Should address recovery of stranded prudent utility investments, include consumer protection laws, address concerns about the feasibility of moving to restructuring or deregulation without entry into a RTO/ISO, and address concerns about shifting the costs for future system upgrades and modernization.

4. How are people in other places responding to this tension? Does that seem feasible in Oregon?

Other states have tried various forms of restructuring, (California, New York, Illinois, Texas and Great Britain) with mixed results. Lessons from other jurisdictions are difficult to translate to Oregon because fact-specific circumstances make it hard to draw universal conclusions. Any of the above regulatory options may be feasible in Oregon, but whether an action is desirable for Oregon depends on a number of factors. The Northwest's unique reliance on hydro generation, thinly populated and remote areas, and the ownership of the vast majority of transmission assets by a federal agency, for instance, create both opportunities and complications that are not present in other jurisdictions and that would likely need to be considered in any significant expansion of customer choice (whether through the utility or independent of it).

5. Are there ways you think Oregon should consider responding to this tension?

Although there was considerable disagreement about what "customer choice" meant, there was general consensus that customers should have some say in the choices available to them. We agreed that it would be interesting to find out what customers really want (through focus groups or other means). For example, do they want more choice of providers of electricity? More options from their existing utility? What do they think either of these options would provide for them? Are they ultimately interested in choices that lead to more environmentally beneficial outcomes, lower cost, social equity, ability to self-generate (self-reliance) or other factors?

We also agreed that Oregon should ensure consumer protection for all customers, and prevent/minimize cost and risk shifting. Members of the group did acknowledge that cost shifting is inevitable, and even desirable in certain instances (assisting lower income customers for example), but must be managed thoughtfully so that customers that avail themselves to "choose" special options should not shift cost and risk to other customers.

[009610.004/349696/3] 009610.004/349696/2

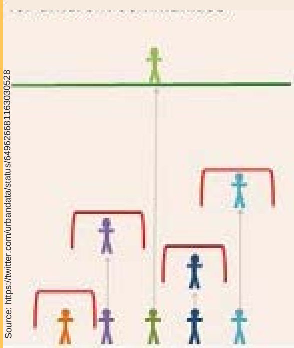
Appendix E-4 Access Group

Is electricity an essential service in society (in Oregon), and if so, how does regulation ensure affordability and reliability for all customers going forward?

The regulatory process ensures access through principles of non-discriminatory, universal service and a cost-of-service, utility business model. But what this approach promises as broadly affordable and reliable leads to disparities at the household level. These principles are not experienced equitably, but our current energy system does not account for this. Historical and growing inequities, including the disproportionate effects of climate change require more targeted strategies to specifically address communities that are most impacted.

Universal Strategies

Structural inequity produces consistently different outcomes for different communities.



Traditional policy-making makes no distinctions among communities and operates under broad assumptions about what is in the public interest. It is encapsulated in the residential rate class that exists in Oregon -- all households pay the same rate, regardless of income or whether they are a renter or homeowner, whether they live in single, multi-family, or manufactured dwellings. Moreover, rate-making and resource planning do not sufficiently take into account external effects of the energy system, such as health, housing, economic development, or recovery from catastrophic events.

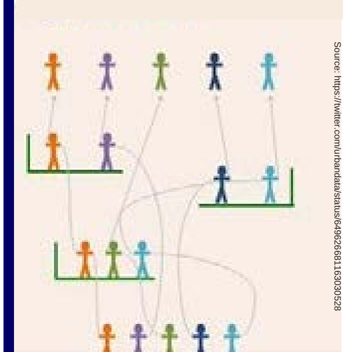
Affordability: Service is priced at rates that are deemed fair, just, and reasonable broadly across customer classes. New resources and infrastructure are acquired in cost prudent ways to keep energy costs low and energy assistance is available as a means to reduce a monthly bill but is not reflected in the price those customers pay, and resources may not be sufficient to meet demand.

Reliability: The power system delivers electricity in a sufficient quantity and with the quality demanded by users, measured by system-wide disruptions (SAIFI, SAIDI, MAIFI).

Access: Currently, access is experienced through the obligation to connect all customers who wish to receive service and to ensure that that service is adequate. Regulatory processes are open to the public, but no resources to support community participation are available, and proceedings can be dense and difficult to navigate.

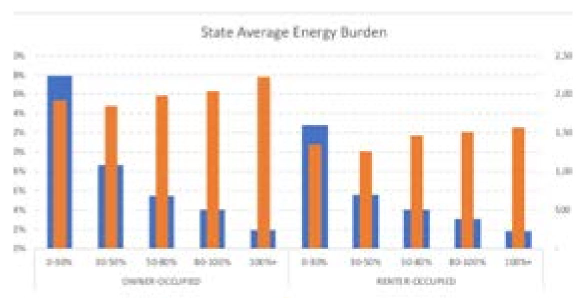
Targeted Universalism

Targeted universalism responds with universal goals and targeted solutions.

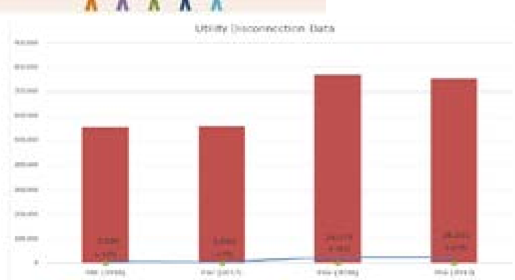


Targeted universalism alters the traditional approach but serves the same universal goals through targeted strategies that account for different systemic experiences and a more equitable balance of benefits and burdens; they specifically address marginalized communities.

Affordability: Low rates for broad customer classes may not be felt by all ratepayers as some households contribute a significant portion of their income toward energy bills. A targeted approach to affordability would directly address and alleviate energy burden and ensure that energy bills do not interfere with other essential needs.



Source: US Department of Energyhttps://openei.org/doe-opendata/dataset/celica-data



Reliability: A system-wide definition does not account for individual disruptions in service due to disconnections, nor does it account for disparities in reliability in remote communities that experience more frequent and longer disruptions. A targeted approach reduces or eliminates disconnections and distributes resources, like generation and storage to communities who experience less reliable service. It also accounts for the fact that some households and communities cannot afford, and are not provided through public investment, technologies which increase resiliency.

Group Members: Amina Moreau (Stillmotion), Brett Sims (Portland General Electric), Carolina Iraheta Gonzalez (Verde), Damon Motz-Storey (Physicians for Social Responsibility), Emily von W. Gilbert (Democratic Socialists of America - Portland), Hannah Cruz (Energy Trust of Oregon), Jaimes Valdez (Spark NW), Jay Ward (Energy Trust of Oregon), Maggie Tallmadge (Coalition of Communities of Color), Margo Bryant (Portland General Electric), María Hernández Segoviano (OPAL Environmental Justice), McKena Miyashiro (Portland General Electric), Natasha Siores (PAC), Oriana Magnera (Northwest Energy Coalition), Shannon Souza (Sol Coast Companies), Tim Lynch (Multnomah County)

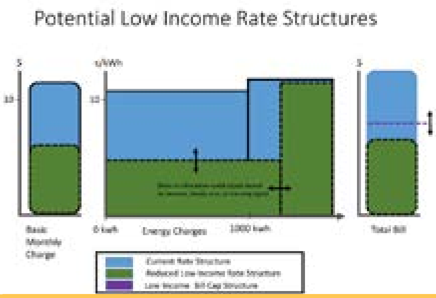
What does "access" mean within a framework of targeted universalism? What strategies could put that framework into practice in Oregon?

Equitable access to service (uninterrupted and not causing undue energy burden), opportunity (jobs, technology and investments, contracting, existing energy conservation and weatherization programs), and decision-making (representation of impacted communities, and valuing of those perspectives). This means targeting resources, designing processes to account for imbalances of power, and rethinking how regulatory authority can be expanded to account for externalities like health, housing, and economic development to provide the greatest targeted benefit.

Thinking Outside the Existing Framework

Targeted universalism addresses the principles of environmental justice: to prevent harm/burden, to provide benefit, and to ensure inclusive and accountable decision-making. Benefits and burdens are distributed equitably and historical and current inequities are addressed, as are future generational impacts. Communities of color, rural communities, and communities experiencing lower incomes often do not have the ability to make smart energy choices and home improvements, due to issues like split incentives, and historical, discriminatory practices, such as housing segregation, that affect home-ownership opportunities, financial equity, and housing type and quality. Currently, there are no good ways to address these issues in the regulatory system, which favors universal strategies over targeted universalism. The strategies listed below are not exclusive and could build on one another to reform the energy system in Oregon in a way that increases access to service, opportunity, and decision-making.

Addressing Energy Burden Through New Rate Class Structures or Bill Caps



More delineation within the residential rate class could stem from income qualification, housing type, or family size through specific rate classes, discount programs (which would create a proportional reduction from both base and energy charges up to a certain usage), or bill or energy burden caps (other states have utilized Percentage of Income Payment Plans). An audit of existing low-income, energy programs will soon begin through UM 1787, a first step in determining the need for alternative strategies to address energy burden, and a potential model for regular evaluation.

Performance-Based Regulation Through Principles of Targeted Universalism

Rather than a “least-cost, least-risk” approach, regulation of utilities' rate of return could connect directly to goals of targeted universalism. Performance metrics could incentivize reducing disconnections, increasing economic development and fair contracting practices, and ensuring that resources and investments reach the communities who need them most, such as those at the end-of-line. Possible metrics could include: greater penetration of distributed energy resourced (DER) and improved interconnection processes with attention to rural communities, practices and policies that reduce disconnections, increased system resiliency upgrades with attention toward areas that are likely to be most impacted by a catastrophic event, the use of good labor policies (such as community benefit agreements), and workforce diversity.

Increasing Meaningful, Accountable, and Inclusive Participation

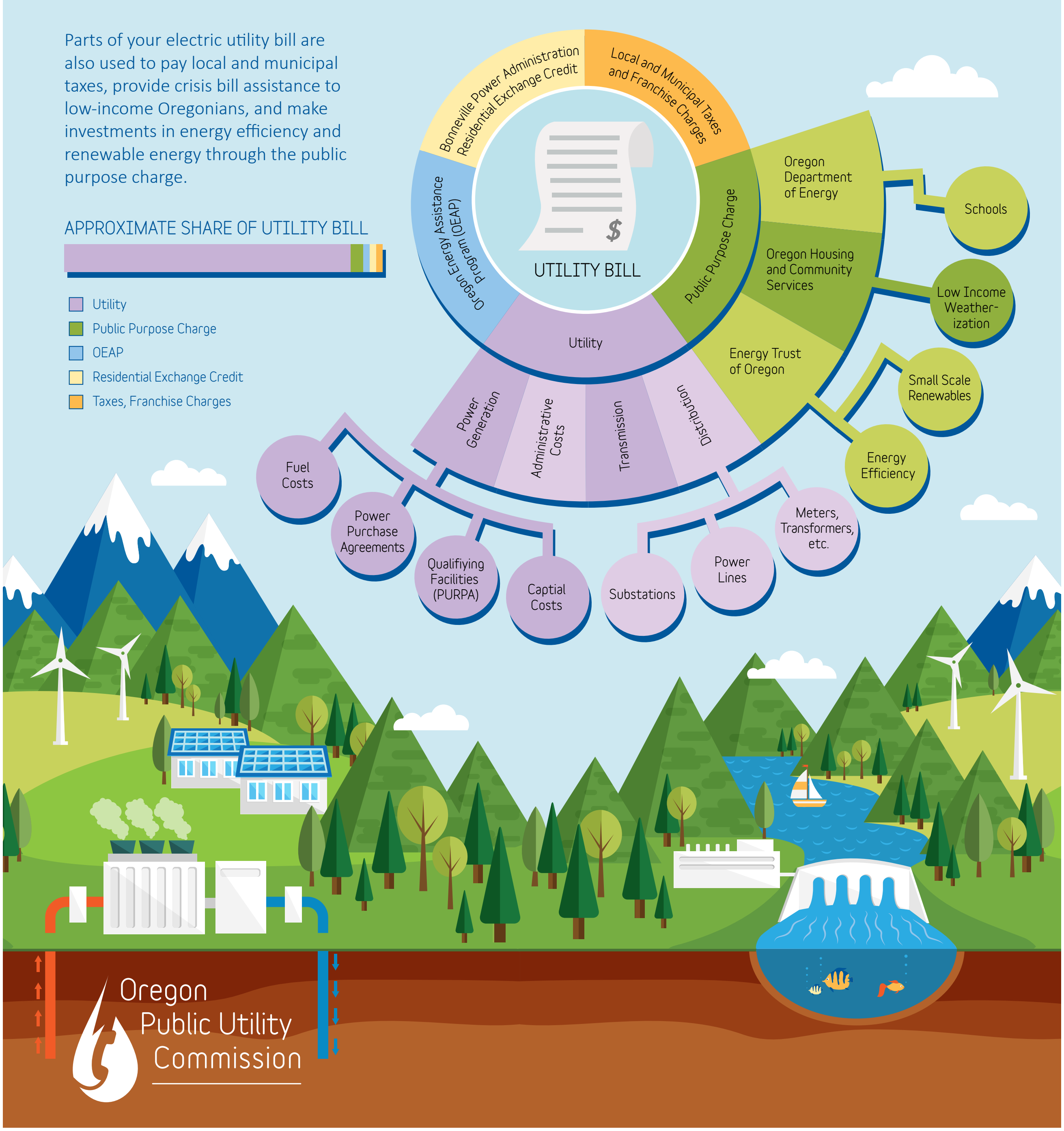
Community perspectives must be actively sought out and engagement must include access to information presented in accessible ways, technical assistance to help make informed decisions, and an opportunity to influence outcomes early in a process. The International Association for Public Participation provides a helpful spectrum of participation goals and messages that range from simply keeping communities informed to empowering them to make decisions. This could include education, interactive workshops, and online resources about energy and how to advocate in regulatory spaces, PUC information made accessible to audiences without technical expertise, community forums and meetings held outside Salem or Portland, new intervenor funding, and community engagement or advocacy based PUC staff to help support and enhance this work. Communities of color, rural communities, tribes and communities experiencing lower-incomes should guide and lead new pilots, investments and technologies to address community needs and provide multiple benefits such as education, employment, health, or resiliency (an example would be upgrades for critical and essential buildings in coastal communities.

APPENDIX F: EVER WONDER WHAT YOUR UTILITY BILL PAYS FOR?

Ever wonder what your **UTILITY BILL** pays for?

The **Public Utility Commission of Oregon** regulates the rates of the state's electric investor-owned utilities and determines what rates they can charge Oregon customers. When you pay your utility bill, these funds are used for a wide variety of things like the electricity used to power your lights, but also the transmission and distribution that is needed to bring electricity to your home or business from a power generation facility.

Parts of your electric utility bill are also used to pay local and municipal taxes, provide crisis bill assistance to low-income Oregonians, and make investments in energy efficiency and renewable energy through the public purpose charge.



APPENDIX G: COMMISSION SUMMARY MEMO OF STAKEHOLDER PERSPECTIVES

SB 978 (2016) required the Public Utility Commission of Oregon (Commission or PUC) to establish a public process to investigate how developing industry trends, technologies, and policy drivers may impact the existing electricity regulatory system. Through the SB 978 process, the Commission and stakeholders have examined and reaffirmed the importance of Commission's existing core guiding objectives for regulation of the electric system—**safety, reliability, affordability,** and **universal access**.[1] The process has prompted reflection on how the Commission defines and assesses these objectives and whether and how the Commission should incorporate **new objectives** for the electric system. Participants have begun to identify **legislative and regulatory changes** that they recommend to better align the regulatory system with their views of appropriate guiding objectives.

The Commission organized participant activity into four categories to reflect its understanding of the areas that warranted further discussion: **Access, Low-Carbon Future, Economic Efficiency, and Customer Choice**.[2] The purpose of this memo is to describe the Commission's understanding of the relevant tensions and open questions following participant work in these areas, to highlight open issues where the Commission needs further input to understand participant recommendations, and determine whether and how to incorporate them in its report to the Legislature due September 15, 2018. The following sections generally describe stakeholder conversations to date on the four categories, as well as a description of a fifth area of discussion that has arisen around participation in Commission processes.

<u>Participation and Inclusion</u>: Participants have raised inclusion in Commission processes as another area that warrants discussion and are seeking ways to promote a greater diversity of involvement in Commission proceedings. Some participants wish to empower customers and more community-based organizations to participate in the Commission process to ensure a broader range of perspectives are represented in regulatory proceedings. The Commission has begun the process of understanding what steps it can take to meaningfully include a broader range of participants.

<u>Access</u>: Should the electric system be structured to ensure affordable, universal access to electricity services for all customer segments, including low income customers?

Affordability has been a guiding principle in terms of the Commission's responsibility to set non-discriminatory, "just and reasonable rates" that reflect the prudent costs of providing electricity service to all who seek it, spreading costs fairly across all customers in broad rate classes according to principles of cost-causation.[3]

Some participants seek a different or more nuanced definition of affordability and universal access. They asked the Commission to refocus the definition on the experience of affordability—the energy burden—for different customers and customer segments. Participants have indicated that electricity is an essential part of modern life that may not be affordable for all customers, therefore not accessible to all. Approaches offered by participants to remediate these impacts include developing more narrow rate classes based on household income or

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[1] The Commission's statutory authority requires "just and reasonable rates" and obligates utilities to provide nondiscriminatory service. The terms "affordability" and "universal access" are not terms used in the Commission's enabling statutes. They are used here to describe these concepts informally and explore their meaning.
[2] Discussion reflected a reasonably broad consensus on the continued centrality of the guiding principles of safety and reliability, as well as the view that security and resilience are important related objectives or sub-objectives that have emerged from digitalization, security threats, natural disasters, and new technology capabilities.
[3] The Commission tracks affordability by measuring customer costs relative to other economic indicators, but not as a central feature of its definition of affordability.

more nuanced rate classes to better account for the potential variation in costs of provide service for the services received by certain groups of ratepayers (such as multi-family), a bill maximum cap, and additional funding for weatherization.

Many suggested regulatory routes to remediate the energy burden of low-income Oregonians would result, without a separate funding source, in increased costs to other customers. Traditionally, regulation has been based on a cost-of-service model in which ratepayers are responsible for paying the cost of the utility service they actually receive, including their share of costs that benefit the entire system. Some ratepayer support for low-income programs that produce system benefits (i.e., weatherization) is already provided as a result of past legislation.

To consider significant cost increases to other ratepayers in support of an equity-based affordability objective requires the Commission to consider whether sufficient authority currently exists to recognize an independent responsibility to mitigate the effects of historical exclusion from societal and/or electric system benefits. To the extent that authority does exist, the Commission would need to consider what the Commission's legal and policy guidelines should be. If the Commission determines that there is no existing legal construct for integrating equity in the manner proposed by participants as a consideration in ratemaking, then policy direction from the Legislature will be necessary to determine if it is appropriate for the Commission to deviate from traditional cost of service considerations.

<u>Low Carbon Future</u>: How should the PUC support the Legislature's carbon reduction policy—as an implementer of state policy or as an agency with an independent climate-related mandate?

Nearly all participants have emphasized that climate change is a serious issue that needs to be addressed in Oregon. They acknowledge that the state lacks a comprehensive strategy to mitigate climate change; most notably, our statewide greenhouse gas reduction goals are not legal requirements that electric utilities must follow. Stakeholders have also emphasized the utility sector's role in decarbonizing the overall economy, including the transportation sector.

The Commission's decarbonization role has been limited to two areas: implementing programs, policies, and rules resulting from legislative direction with which regulated utilities must comply (i.e., RPS), using safety, reliability, and affordability as its guiding principles; and considering regulation of carbon emissions as an economic risk factor in planning.[4] Many participants believe that the Commission should address carbon emissions more explicitly, but have not defined a specific independent role or objectives appropriate for the Commission today.

Implementation of state carbon policy as applied to regulated utilities could be a clear role. The Oregon Legislature has convened a Joint Committee on Carbon Reduction in preparation to consider a comprehensive carbon policy during the 2019 Legislation Session. Participants agree that if one of the appropriate goals for the utility sector is to reduce emissions, then a

[4] Under its current decision-making approach the Commission uses a least-cost, least-risk framework. This means the Commission balances the risks presented by proposals with the total cost to ratepayers. Environmental costs which are not currently regulated or likely to be regulated in the future by state, federal government or local jurisdictions are not accounted for in this balance test, nor can they be directly imposed on utilities.

legal requirement that caps carbon is an integral—and some say the only appropriate—way to define a decarbonization objective for PUC implementation.

Other participants have asked whether electric sector policy, separate from and in addition to a statewide carbon policy, should be considered to influence other sectors, such as transportation, to rely on electricity as a fuel source to reduce overall emissions. They also have suggested a PUC role in decarbonization beyond planning, compliance oversight, and implementation of specific state policy. For this to be a recommendation to the Legislature, particularly if statewide carbon policy is adopted, it would be important for participants to define the parameters and objectives of such a PUC role, including addressing interactions with roles more appropriate for other state agencies.

<u>Customer Choice</u>: How should the Commission balance some customers' desire for greater choice and control with maintaining high quality, affordable service for less engaged customers? What principles should the Commission use to structure available choices?

As technology has evolved, state policies have consistently directed the Commission to give customers more options for energy services. Those options have been available from both utilities and third parties (direct access, net metering, portfolio options, and community solar). However, there is no consensus that maximizing the choices available to individual customers is itself an inherent guiding objective for the Commission.

Customer satisfaction is a consensus goal of participants, but there is no cohesive view of what customers want. In the aggregate, customer desires are reflected in state law and in the Commission guiding principles of safety, reliability, affordability, and universal access. Participants have indicated that customer choice can function as a vehicle to move public policy choices forward and provide customers with more specialized services and choices about generation source. Surrounding customer choice is the question of who provides the services—i.e., what mix of options from the incumbent electric utility or third-party providers is most appealing for customers and best adapted to other policy goals and guiding principles.

Customer choices, depending on how they are designed, can support or be in tension with other guiding principles, such as economically efficient carbon reduction and maintaining a centralized utility system to ensure affordable, universal access for all. This conversation is complicated by how to manage individual choice in a system that was designed around socializing the cost of utility service across classes of customers. Additionally, stakeholders have raised questions about how to manage what could become stranded assets and costs as utility customers self-select out of traditional cost-of-service tariffs. Some participants note that accelerating technology development may offer customers options that outpace or eclipse these regulatory considerations.

To date, the state's approaches to providing customer choice have not included benefits to the utility system as a fundamental criteria or aspect of their design. A guiding principle for services and options offered to customers could be that they provide a benefit to the regulated utility system, even where the service is not provided by the utility.

<u>Economic Efficiency</u>: Does the regulatory system incent the most efficient outcomes? Is there another approach that would result in better outcomes given rapid technology development and changes in policy objectives?

For the purposes of this process, the Commission interprets economic efficiency as designing and operating the regulatory system to meet customer needs and policy requirements, minimizing risks and inefficiency, to achieve the most affordable outcome for all ratepayers over time.[5] In addition, economic efficiency means ensuring that energy system decision makers (e.g. consumers, utilities, innovators, resource providers, etc.) are motivated by tools and conditions to make the most efficient choices.

Economic efficiency is a useful frame for the Commission to consider two areas of inquiry: ratemaking and industry structure. The first area is the incentives that exist in the cost-of-service ratemaking formula for investor-owned utilities as applied in Oregon, and whether the method of regulation produces the most economically efficient way to achieve desired outcomes. The second is whether moving to an industry structure based on wholesale market competition, in areas where natural monopoly conditions are absent or less significant, would better encourage economically efficient achievement of desired outcomes than a vertically integrated monopoly structure.

As to the first area—ratemaking—the traditional cost-of-service approach has worked to encourage utility capital investment by allowing regulated utilities the opportunity to earn a return on capital investments. This has served to encourage development and investment in the utility system, necessary to ensure ratepayers receive safe and reliable service and, historically, to incent utilities to expand the system to reach all customers. Today, some historical incentives may be less necessary; retaining them could obscure economically efficient achievement of today's desired outcomes.

Participants have discussed the possibility of compensating utilities based on their performance in meeting certain metrics rather than based on invested capital—i.e., using Performance Based Ratemaking (PBR). Metrics can be tied to desired outcomes (for example, customer satisfaction, reliability, or carbon reductions). If the opportunity to earn a return is based on achievement of such metrics, the incentive for utilities to invest in capital resources can be reduced. In order to better understand the value of a performance based approach, the Commission would need to begin to collect data on metrics around utility performance against desired outcomes and whether or not economic efficiency and performance against other goals could be improved with a change in the utility incentive structure.

In the second area—wholesale industry structure—participants have generally agreed that aspects of traditional utility service, such as transmission and distribution, are still true monopoly services. However, there are services provided by a utility, such as generation development and ownership, that are widely understood to no longer have the same natural monopoly characteristics as they once did. Some participants emphasize that competition in generation ownership will capture innovation and lead to more economically efficient outcomes. The benefits of competition, they believe, cannot fully be captured through existing procedures to promote competition nor by changing utility ratemaking incentives. Instead, wholesale market restructuring that divests utilities of generation ownership is seen by some as a superior solution. Even assuming agreement with this view, some note that the Commission and/or the

[5] Several participants objected to framing this inquiry around economic efficiency, preferring competition, innovation, and economic development as frames. This framing was intentional. From the Commission's perspective, competition and innovation are two important means to achieve desired outcomes for customers in an economically efficient manner. Economic development and community well-being are indirectly impacted by Commission decisions, but have not been—and are not recommended as—objectives to directly guide Commission decisions.

Legislature would need to consider whether the presence of an organized market to economically dispatch generation must be seen as a precondition to industry restructuring.

Participants do agree that state policy requirements should be applied evenly and met by all market participants. And, regardless of participant views on regulatory incentive alignment and wholesale restructuring, participants agreed that further development of western market functionality beyond the Energy Imbalance Market would improve economic efficiency in resource operations for all.