Oregon Low Carbon Fuel Standards
Advisory Committee Process and Program Design
January 25, 2011
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I. Executive Summary

Transportation produces over a third of Oregon’s greenhouse gas pollution. If Oregon is to reduce its contribution to climate change, greenhouse gas pollution from transportation must be reduced. There are three essential approaches that must be pursued for a comprehensive strategy: cleaner vehicle technology, reducing the amount of miles traveled, and decreasing the carbon intensity (i.e. greenhouse gas emissions) of the transportation fuel we use. A combination of state and federal initiatives is making vehicle engine technology cleaner, and Oregon continues to develop programs to reduce the number of miles traveled. Oregon’s low carbon fuel standards (LCFS) program will address the “third leg of the stool” by requiring reductions in the average carbon intensity of Oregon’s fuel.

In 2009, the Oregon legislature authorized the Environmental Quality Commission to develop a low carbon fuel standards program for Oregon. The goal of the program is to reduce the average carbon intensity of conventional gasoline and diesel fuel by ten percent over a ten year period. This can be achieved through the increased use of lower carbon, alternative fuels. The low carbon fuel standards program would not mandate the use of any specific fuel; it does not pick “winners” and losers” in the fuels market. Instead, suppliers and distributors of petroleum fuels can use any mix of traditional fuels and lower carbon alternative fuels they desire to meet the standards. As the standards tightens over time, fuel suppliers and distributors will need to increase the use of lower carbon fuels.

Oregon’s low carbon fuel standards would promote the use of lower carbon, alternative fuels such as ethanol and biodiesel; as well as electricity, natural gas, and biogas, all of which can all help Oregon meet the standards. Low carbon fuel standards will also help promote the development of in-state low carbon biofuels production, as well as increased electric vehicle use. DEQ’s economic analysis suggests that low carbon fuel standards will facilitate growth in these low carbon fuel sectors, which in turn is expected to produce significant economic benefits for Oregon, creating new jobs and personal income that stays and circulates within this state.

To design Oregon’s low carbon fuel standards program, DEQ convened an advisory committee of diverse stakeholders to discuss, debate, and offer recommendations for various design elements of Oregon’s low carbon fuel standards. DEQ spent over a year working with the committee to explore many technical and policy issues such as life-cycle carbon intensities of various fuels, flexible compliance approaches, including the use of carbon credits, effects of indirect land use on fuels, and safe guards to protect fuel producers and the public against fuel shortages or price spikes.

The goal of the program is to reduce the average carbon intensity of conventional gasoline and diesel fuel by ten percent over a ten year period.

Low carbon fuel standards will produce significant economic benefits for Oregon, creating new jobs and personal income that stays and circulates within this state.
Over the year, DEQ’s advisory committee reached agreement on some points, and disagreed on others, but always gave DEQ the benefit of their experience and perspective. DEQ wishes to sincerely thank them for their time and service.

This report describes DEQ’s proposed design for an Oregon low carbon fuel standards program, as guided by advice from the committee, and includes several special features required by the Oregon legislature in House Bill 2186 (2009). In designing the program, DEQ carefully considered recommendations from each advisory committee member.

In early 2011, DEQ will discuss this report and program design with the Oregon Legislature. DEQ’s intent is to begin public rulemaking for Oregon’s proposed low carbon fuel standards in the summer of 2011.

Complete information about DEQ’s low carbon fuel standards program design and advisory committee process, including issue papers, presentations, and committee meeting summaries can be found in this report and at the following website.
www.deq.state.or.us/aq/committees/lowcarbon.htm
II. Oregon Low Carbon Fuel Program: At A Glance

This table summarizes the key program elements of DEQ’s proposed low carbon fuel standards program, and alternatives considered by the low carbon fuel standards advisory committee and DEQ. A brief summary of the rationale for DEQ’s proposal is also included. For brevity, this summary does not explain all terminology. For more explanation and a detailed description of DEQ’s proposal and rationale for each issue, please refer to the relevant section in the low carbon fuel standards report (page reference provided). For detailed advisory committee comments please refer to Appendix A: Summary of Advisory Committee Input.

Table 1: Summary of Low Carbon Fuel Standards Proposals and Program Design

<table>
<thead>
<tr>
<th>1) Covered Fuels and Regulated/Opt-in Fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a) Covered Fuels <em>(See page 53 For details)</em></td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
</tr>
<tr>
<td>• Diesel</td>
</tr>
<tr>
<td>• Gasoline</td>
</tr>
<tr>
<td>• Electricity</td>
</tr>
<tr>
<td>Fuels used for transportation includes off-road fuel.</td>
</tr>
<tr>
<td>Not covered: Propane</td>
</tr>
<tr>
<td><strong>Alternatives Considered</strong></td>
</tr>
<tr>
<td><strong>Rationale</strong></td>
</tr>
<tr>
<td>Advisory committee members requested that propane be included as opt-in to the low carbon fuel standard. <em>Arguments in favor — 1) Propane could assist regulated parties in meeting the low carbon fuel standards.</em></td>
</tr>
<tr>
<td>House Bill 2186 specifically authorizes the exemption of propane from the low carbon fuel standards.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>1b) Regulated and Opt-in Fuels <em>(See page 54 for details)</em></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regulated (compulsory participants) under low carbon fuel standards:</strong></td>
</tr>
<tr>
<td>• Gasoline</td>
</tr>
<tr>
<td>• Diesel</td>
</tr>
<tr>
<td>• Ethanol</td>
</tr>
<tr>
<td><strong>Opt-In under low carbon fuel standards</strong> (can choose to opt-in to all requirements to generate credits for sale):</td>
</tr>
<tr>
<td>• Compressed or liquefied hydrogen</td>
</tr>
<tr>
<td>• Biogas LNG</td>
</tr>
</tbody>
</table>
Alternatives Considered

Alternative 1: Allow biofuels providers with a biofuel carbon intensity lower than the 2022 standards to opt-out of the low carbon fuel standards requirements, or make biofuels providers opt-in. *Arguments in favor — 1) Some biofuels have very low carbon intensities.*

Alternative 2: Require all fuels listed as “covered fuels” to meet all reporting and compliance obligations of the low carbon fuel standards. Under this alternative, there would only be regulated parties, and no opt-in parties. *Arguments in favor — 1) Credits from all fuel types will be necessary to meet the low carbon fuel standards.*

Alternative 3: Allow only fossil CNG supplied from North American sources to opt-in, instead of allowing any fossil CNG to be opt-in. *Arguments in favor — 1) N. American natural gas has a low carbon footprint, but non-N. American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.*

Alternative 4: Regulate all fossil LNG to be regulated, instead of allowing LNG made from natural gas supplied from a pipeline to be opt-in. *Arguments in favor — 1) LNG could have a higher carbon intensity than the low carbon fuel standards in 2022, depending on the technology used.*

Alternative 5: Allow all fossil LNG to be opt-in. *Arguments in favor — 1) The low carbon fuel standards should encourage alternative fuels, and allowing opt-in for all LNG would accomplish this.*

Rationale

Credits from biofuels will be needed for the program; biofuels are currently commercialized and used in large volumes, so there is no need to allow them to opt-out.

Requiring all fuels to meet all provisions of the low carbon fuel standards does not provide compliance flexibility for small volume providers. For example, a rural utility that has one household with an electric vehicle would need to meet all of the provisions in the standards. If low carbon fuels used currently in small volumes are opt-in, the fuel provider can consider their current resources, volume of fuel used, and potential for selling credits before opting-in. Allowing lower carbon fuels to opt-in is a flexible implementation approach that reduces compliance cost.

If LNG is imported into Oregon, gasified, distributed by pipeline, and then re-liquefied, the finished LNG is mixed with pipeline natural gas, and maintains a lower than the proposed 2022 low carbon fuel standards carbon intensity. Alternatively, LNG imported to Oregon and used in liquefied form could be high carbon intensity, depending on the technology used. DEQ’s proposal regulates any fuel that will be high carbon intensity, while allowing lower carbon intensity LNG to opt-in.

2) Regulated and Opt-in Parties

2a) Gasoline, diesel, biomass-based diesel and ethanol *(See page 57 for details)*

DEQ Proposal

**Regulated fuels. Regulated party:** Producer, Oregon Large Importer (more than 50,000 gal imported per year, and Oregon Small Importer (less than 50,000 gal imported per year)

**Transfer of compliance obligation with sale of fuel:**

- If fuel is sold to a producer or Oregon Large Importer, the seller decides if the
compliance obligation transfers with the sale of the fuel.

- If the fuel is sold to an Oregon Small Importer or a person that does not import fuel into Oregon, the buyer can refuse the compliance obligation.

**Alternatives Considered**

<table>
<thead>
<tr>
<th>Alternative 1</th>
<th>Regulated party is entity that pays ODOT fuels tax. Arguments in favor — 1) Consistency with fuels tax and greenhouse gas reporting rule. 2) Person who pays ODOT fuels tax knows the fuel will be used in Oregon.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternative 2</td>
<td>No “Oregon Small Importer” designation. This would lump all fuel importers in one category. Arguments in favor — 1) This designation of a small importer is not needed, since most small importers will not own fuel as it is imported into Oregon.</td>
</tr>
</tbody>
</table>

**Rationale**

Consistency with ODOT fuels tax and DEQ’s greenhouse gas reporting rules was an important consideration in choosing regulated parties. DEQ’s research and discussion with stakeholders showed that the entities that must adhere to the standard needs to be different than the entities regulated under ODOT fuels tax and DEQ’s greenhouse gas reporting rules for the following reasons.

Ideally, the point of regulation is upstream to minimize the compliance population. DEQ’s proposal is the only proposal that initially regulates upstream entities (that is, producers and importers responsible for gasoline and diesel transportation fuels), rather than downstream distributors and fueling stations. Downstream regulation would occur if the regulated party was the person paying the ODOT fuels tax. In addition, ODOT fuels taxpayers will not necessarily know the carbon intensity of the biofuels they purchase, but the importer will.

The low carbon fuel standards exemptions do not align with ODOT fuels tax payers. None of the other reporting requirements consider lifecycle emissions. Non-road fuels are not covered under ODOT’s tax program, but are included in the low carbon fuel standards. For greenhouse gas reporting, different reporters and emission quantification methods are involved.

Although DEQ’s proposal allows some transfer of compliance obligation down the chain of owners, it does not always go down to the level of ODOT fuels tax. It is important that the compliance obligation reside with entities that have control over the type and carbon intensity of imported fuel. Allowing the transfer of the compliance obligation also increases flexibility in the regulation and decreases compliance costs.

A stakeholder subgroup explored the option of exempting small gas stations. But some participants felt strongly that small gas stations should not be exempt from the low carbon fuel standard because of fairness issues. Under DEQ’s proposal, small importers would have compliance obligation for fuel they import, but could refuse compliance obligation for fuel bought in Oregon. This flexibility gives small gas stations with limited resources the ability to manage participation in the low carbon fuel standard for all of the fuel they buy. Small gas stations could also avoid becoming a regulated party by only taking possession of fuel when it is delivered to their facility.

**2b) Compressed Natural Gas (CNG) from fossil sources (See page 59 for details)**

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Opt in fuel. Opt-in party: Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Transfer of credits with sale of fuel: Transfer only occurs if seller and buyer agree.</td>
</tr>
</tbody>
</table>
### Alternatives Considered

**Alternative 1:** Do not allow a natural gas utility to participate in program if infrastructure or fuels are subsidized by ratepayers. *Arguments in favor — 1) Using ratepayer funds to subsidize infrastructure or fuel cost creates an anti-competitive environment in which private enterprise would struggle to compete.*

This opt-in choice captures only the transportation use of natural gas, and provides some program flexibility. There is also an incentive for the owner of the fuel dispensing equipment to provide public access to CNG fuel and earn credits from sales to the public. Because any non-North American natural gas would be mixed with North American gas in the pipeline, the carbon intensity will likely remain lower than the 2022 low carbon fuel standards.

It is DEQ’s understanding that natural gas utilities cannot use ratepayer funds to subsidize fuel or infrastructure cost for sales of transportation CNG to the public.

### Rationale

**2c) Liquefied Natural Gas (LNG) from fossil sources** *(See page 60 for details)*

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Opt-in: Any LNG produced from natural gas supplied through a North American pipeline.</th>
<th>Regulated: all other LNG</th>
<th>Opt-in or Regulated party: Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon</th>
<th>Alternative 1: Do not allow a natural gas utility to participate in program if infrastructure or fuels are subsidized by ratepayers. <em>Arguments in favor — 1) Using ratepayer funds to subsidize infrastructure or fuel cost creates an anti-competitive environment in which private enterprise would struggle to compete.</em></th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternatives Considered</td>
<td></td>
<td></td>
<td></td>
<td>This proposal captures only the transportation use of natural gas. It also provides some flexibility because the regulated or opt-in party could either be a natural gas company who owns the LNG fuel dispensing equipment, or it could be a large fleet owner that decided to put in a fueling station. It is DEQ’s understanding that natural gas utilities cannot use ratepayer funds to subsidize fuel or infrastructure cost for sales of transportation LNG to the public.</td>
</tr>
<tr>
<td><strong>2d) Biogas (CNG or LNG)</strong> <em>(See page 62 for details)</em></td>
<td>Opt-in fuels. Opt-in party: Producer or importer of the biogas, if the producer or importer retains custody in the pipeline. Producer or importer must show that the fuel has been used for transportation. <strong>Transfer of credits with sale of fuel:</strong> Transfer only occurs if seller and buyer agree.</td>
<td>Alternative 1: Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon. <em>Arguments in favor — 1) The entity that owns the fuel dispensing equipment in Oregon will have documentation that the fuel was used for transportation.</em></td>
<td><strong>Alternative 2:</strong> In order to demonstrate that biogas has been used for transportation purposes, a producer or importer could use a “biogas swap” instead of paying for transportation in the pipeline. In a biogas swap, the producer contracts for production and sale of biogas without transfer to that customer. <em>Arguments in favor — 1) This is a common practice in the electricity market and eliminates pipeline transfer fees. Because greenhouse gases are not local pollutants, actually reducing emissions in Oregon is not necessary. 2)</em></td>
<td></td>
</tr>
</tbody>
</table>
### Rationale

Not allowing biogas swaps creates an unfair advantage of electricity over gas.

This choice of an opt-in party will encourage low carbon alternative fuels. If the producer or importer pays the pipeline operator for the transfer of biogas through the pipeline system, this can demonstrate the physical pathway of the biogas from the producer or importer to the transportation use.

### 2e) Hydrogen (See page 63 for details)

**DEQ Proposal**

- **Opt in fuel. Opt-in party:** Person who owns the fuel at the time the finished fuel is made or imported into Oregon.
- **Transfer of credits with sale of fuel:** Transfer only occurs if seller and buyer agree.

**Rationale**

The finished fuel can either be made prior to fuel dispensing, or can be made in a vehicle. This choice for opt-in parties covers both possibilities.

### 2f) Electricity (See page 63 for details)

**DEQ Proposal**

- **Opt in fuel. Opt-in party:** Opt-in priority:
  1. Bundled services provider;
  2. Electricity provider; or
  3. Owner and operator of electric charging equipment (including homeowners).

The electricity opt-in period will be for one year. The opt-in party with the highest priority (above) will maintain opt-in rights for a particular service for the full one-year period.

- **Transfer of compliance obligation with sale of fuel:** None.

**Alternatives Considered**

- **Alternative 1:** Opt-in is for more than one year. *Arguments in favor — 1) This will help ensure that electric vehicles can take advantage of the low carbon fuel standards as a market driver.*

**Rationale**

This choice of an opt-in party captures only the transportation use of electricity and provides flexibility through an opt-in process. As with other fuels, DEQ prefers an opt-in party that is larger and higher up in the chain of fuel distribution (closer to the source). In the case of electricity, DEQ provided the option for owners of charging equipment to opt-in, with the recognition that utilities might not opt-in until the latter part of the program timeline.

### 3) Exemptions

#### 3a) Exemptions for fuel users (See page 66 for details)

**DEQ Proposal**

Low carbon fuel standards do not apply to fuel users. Any fuel user may possess fuel that does not meet the low carbon fuel standard. This includes, but it not limited to the operator or owner of a farm truck, log truck and other on-road and non-road engines.

#### 3b) Exemptions for fuel used in specific applications (See page 66 for details)

**DEQ Proposal**

Fuel used in the following vehicles, equipment or engines:

- **Fuels used in farm vehicles, farm tractors, implements of husbandry, and log trucks as identified by statute.** House Bill 2186 specifically exempts fuels used for
these purposes from the LCFS.

- **Fuels used in engines with special performance needs, including aircraft, racing vehicles, military tactical vehicles and military tactical support vehicles.** This use is exempted due to the engine’s performance characteristics and potential special fuel needs.

- **Fuels used in oceangoing vessels and Class 1 locomotives.** Ocean-going vessels and Class 1 locomotives travel long distances and could avoid regulation simply by changing their purchasing patterns, which would provide no emissions reduction benefit.

- **Fuels used in short line locomotives will be exempt until 2017.** Oregon DEQ lacks sufficient information on the fuel distribution system, the volume of fuel affected, or the degree to which distributors of locomotive engine fuel might depend on credits purchased under a low carbon fuel standard. To allow time to investigate these issues, DEQ proposes to exempt fuel used in short line railroads until at least 2017.

### Alternatives Considered

<table>
<thead>
<tr>
<th>Alternative 1: Exempting harborcraft. <em>Arguments in favor — 1)</em> Interstate rail and Columbia River/Snake River barge freight compete and there might be the perception of a competitive advantage afforded to interstate rail companies if fuel used in interstate rail is exempt.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternative 3: Exemption for off-road construction equipment. <em>Arguments in favor — 1)</em> This would make it more likely that exempt farm uses could obtain fuel that is not impacted by LCFS.</td>
</tr>
<tr>
<td>Alternative 4: Short line rail should not be exempt. <em>Arguments in favor — 1)</em> The switch to cleaner fuels requires a one-time education effort, and a one-time educational effort should not be a barrier to participation in the low carbon fuel standards.</td>
</tr>
<tr>
<td>Alternative 5: No industry exemptions. <em>Arguments in favor — 1)</em> Exemptions perpetuate the myth that biofuels are problematic.</td>
</tr>
</tbody>
</table>

### Rationale

DEQ worked with stakeholders to identify practical methods for documenting and tracking sales to exempt uses such as farm vehicles and log trucks, to set reasonable exemption thresholds for small volume fuel producers, and to address issues associated with fuel used in locomotives.

There is nothing in the low carbon fuel standards that would prohibit any fuel user from obtaining unblended fuels. Because the standards do not provide blending requirements, and because of the deferrals and exemptions for fuel supply and price, these exemptions are not necessary.

DEQ is implementing the exemptions required in statute.

### 3c) Exemptions for specific alternative fuels *(See page 67 for details)*

- **Liquefied petroleum gas (also known as propane).** House Bill 2186 specifically authorizes the exemption of propane from the low carbon fuel standards.

- **Small Volume Fuels Producers.** Producers of alternative fuels in small volumes may choose to be exempt or to opt-in to the low carbon fuel standards to earn credits or
deficits.

- Individual small-scale alternative fuel producers with 10,000–gasoline
gallons equivalent annual production or less may choose to opt-in to, or be
exempt from the low carbon fuel standards.

- Individual small-scale alternative fuel producers with 10,000 to 50,000–
gasoline gallons equivalent annual production that is used entirely by the
fuel producer.

- Research, development or demonstration facilities that meet the definition in
OAR 330-090-0105 62(a) (A-C) can apply for a time-limited exemption.

- **Fuels Used for Transportation in Small Volumes:** Fuel that are used in Oregon in
total aggregate volumes of less than 360,000 gasoline gallon equivalent (gge) per year
can request an exemption. This applies to a fuel/feedstock combination.

### Alternatives Considered

**Alternative 1:** No exemptions for small volume fuel producers.

Exemptions for small volume fuels producers could help small-scale producers by
reducing regulatory burden given their small size and output. DEQ does not want to
discourage new fuel development.

House Bill 2186 allows the Environmental Quality Commission to establish an exemption
threshold for fuels. California’s low carbon fuel standards exempts fuels used for
transportation in volumes less than 3.6 million gge per year. Oregon’s fuel use is
approximately ten percent of California’s.

### 3d) Reporting exempt fuels (See page 68 for details)

#### DEQ Proposal

Compliance reporting for exempt fuels will need evidence to support the exempt use. For
example, delivery documentation (such as avgas delivered to an aircraft fuel tank at an
airport) or an affidavit verifying exempt use of the fuel. (As might be the case for the
owner-operator of a log truck.)

#### Rationale

DEQ worked with stakeholders to identify practical methods for documenting and tracking
sales to exempt uses. DEQ’s proposal provides practical ways that a fuel can be exempted
from the low carbon fuel standards.

### 4) Setting the Baseline Standards (See page 69 for details)

#### DEQ Proposal

Two standards. One for gasoline and its substitutes, and one for diesel and its substitutes.

DEQ used 2007 fuels data from the U.S. Energy Information Administration (EIA) as a
surrogate to estimate 2010 gasoline and diesel volumes and sources of fuel. 2007 EIA data
was the latest, most complete data set available at the time the work was completed.

- Adjust these data with Oregon and City of Portland renewable fuel standards (10
percent ethanol statewide, 2 percent biodiesel statewide, 5 percent biodiesel in
Portland).

- Adjust higher carbon intensity crude volumes with the most recent data available
from Canada (2009)

DEQ proposes to use 2010 as the baseline year, not 2007, because the baseline should
DEQ did not propose including electricity, CNG, LNG, or biofuels used above renewable fuel standards required levels in the baselines. The use of these fuels is not currently tracked, and quantification would be difficult. Additionally, these fuels are used in small volumes compared with other fuels, and the impact on the baseline standards would be small.

### Alternatives Considered

**Alternative 1:** A single baseline standard that averages the carbon intensities for gasoline and diesel and their substitutes together. When switches from gasoline to diesel occur in the light-duty passenger vehicle market, an Energy Economy Ratio (EER) could be applied. *Arguments in favor — 1) A single baseline provides more compliance flexibility. 2) Oregon is a relatively small fuel consumer and we will not drive fuel innovation on our own. 3) Switching more of the light-duty fleet to diesel would have an immediate reduction in carbon emissions due to the EER of diesel as compared to gasoline. Reducing emissions in the short run is more valuable than in the long term. Having two separate standards will delay the reduction in emissions, which makes the reductions worth less. 4) The statute says to reduce the carbon intensity of the whole fuel pool, and therefore one standard is appropriate. 5) This alternative evaluates each fuel for greenhouse gas reductions and is therefore fuel-neutral.*

**Alternative 2:** Use 2007 biofuels volumes in the baseline. *Arguments in favor — 1) Captures Oregon’s biofuels investment and GHG emission reduction since 2006.*

### Rationale

DEQ proposes two baseline standards for several reasons:

- Promotes development of lower carbon intensity fuels for both gasoline and diesel fuels;
- Provides some flexibility for regulated parties, since credits earned on the diesel side can be used on the gasoline side, and vice versa;
- Eliminates the need for a complex (and possibly infeasible) mechanism to identify and allocate carbon credits due to fuel switching from gasoline to diesel when applying a diesel EER to light-duty diesel use (as would be needed if there were a single baseline.);
- Prevents diesel used in light-duty applications from becoming a “low carbon fuel.” This could result in less incentive for fuel producers to reduce the carbon intensity of alternative diesel fuel since diesel fuel used in light-duty applications would be below that of the 2022 standard;
- The one-pool option achieves less carbon reductions;
- The economic analysis showed little additional economic benefit from a “one pool” compliance scenario; and
- Petroleum diesel is a baseline fuel, in widespread use at the time the low carbon fuel standards were authorized. The statute directs the Environmental Quality Commission to achieve reductions from baseline.

### 5) Low Carbon Fuel Standards Compliance Schedule *(See page 72 for details)*
### DEQ Proposal

**Proposed program timeline:**
- 2012: Reporting only
- 2013: First compliance year
- 2022: 10 percent reduction achieved

DEQ may provide an additional reporting year to address implementation issues discovered in the 2012 reporting year. This would move the first compliance year from 2013 to 2014 and the horizon year to 2023.

The compliance schedule is back-loaded so that small carbon intensity reductions are required in early years and larger reductions toward the end of the program.

### Alternatives Considered

**Alternative 1:** 2010-2020 program timeline. *Arguments in favor — 1) It makes sense to be on the same timeline as California. 2) There is public support for reducing pollution and breaking oil dependence. 2020 is a workable horizon year and brings greenhouse gas emission reductions sooner. 3) A delay in program implementation means a delay in investment opportunities and greenhouse gas emission reductions for Oregon.*

**Alternative 2:** If timeline is delayed from 2010 through 2020 to a later year, the projected greenhouse gas emission reductions lost due to the delay should be made up in subsequent years. *Arguments in favor — 1) This would assure that the low carbon fuel standards achieve desired impact.*

**Alternative 3:** 2014-2024 program timeline. *Arguments in favor — 1) It makes sense to be on the same timeline as Washington (note: Washington is still considering a timeline)*

### Rationale

DEQ chose a 2012-2022 program timeline because House Bill 2186 approximated a ten-year program phase-in period. Between now and 2012, DEQ must complete draft rules; vet these materials with the public, stakeholders and legislature; and conduct a public rulemaking process. Given that schedule, it is likely that the Environmental Quality Commission would not adopt a final rule for low carbon fuel standards until December 2011. A 2022 horizon year allows time to successfully launch the program and meet the ten percent emission reduction requirement over roughly a ten-year period.

The proposed back-loaded compliance schedule allows more time to develop lower carbon intensity fuels, and more widespread use of alternatively fueled vehicles and infrastructure.

### 6) Carbon Intensity

#### 6a) Calculation Methodology for Carbon Intensity of Oregon’s Fuels *(See page 124 for details)*

**DEQ Proposal**

**Statewide average:** Gasoline, diesel, electricity, and compressed fossil natural gas derived from natural gas that is not imported to Oregon in liquefied form.

- **EXCEPTION:** An electricity provider who only provides electricity for transportation and is exempt from Oregon Public Utility Regulation by ORS 757.005 (1)(b)(G) can obtain a carbon intensity number that is different than the statewide average carbon intensity for electricity and specific to the electricity they supply.

**Individual Carbon Intensity for each fuel producer:** Ethanol, biomass-based diesel, LNG, Biogas (CNG and LNG), hydrogen, any fossil CNG produced from natural gas arrives in Oregon in liquefied form, and any new fuel.
<table>
<thead>
<tr>
<th>Alternatives Considered</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gasoline and Diesel</strong></td>
<td>DEQ’s proposal maintains a balance between workload and detail.</td>
</tr>
<tr>
<td>Alternative 1: Individual carbon intensities for each gasoline or diesel producer, instead of a statewide average for all producers. <em>Arguments in favor — 1)</em> Consistency with biofuels. 2) Individual carbon intensities are a better way to incent lower carbon petroleum.</td>
<td>Because House Bill 2186 authorizes reduction in the statewide carbon intensity of Oregon’s fuels, it is consistent with the statute to use statewide averages of carbon intensity for some fuels.</td>
</tr>
<tr>
<td>Alternative 2: Gasoline and diesel producers could obtain individual carbon intensity if refinery efficiency improves by 5 gCO2e/MJ or 10 percent, whichever is less. <em>Arguments in favor — 1)</em> If an individual refinery makes efficiency improvements to their production process, it should be reflected in their carbon intensity.</td>
<td>Electricity: DEQ, supported by the advisory committee, chose to propose statewide average carbon intensity for several reasons: it creates a level playing field between geographic areas, the carbon intensity is expected to decrease due to the Renewable Portfolio Standard, and an average would equitably represent the carbon intensity of Oregon’s electricity as a whole. Does not create a geographical bias for electric vehicle investment based on the carbon intensity of local electricity. A statewide average is easier and provides more regulatory certainty. Based on DEQ’s conversations with utilities, the use of individual carbon intensities is unlikely to motivate utilities to reduce the carbon intensity of their electricity or affect their decision to opt-into the low carbon fuel standards.</td>
</tr>
<tr>
<td>Alternative 3: Individual carbon intensities for each electric utility and electricity provider. <em>Arguments in favor — 1)</em> The carbon intensity of electric utilities varies greatly, and utilities with lower carbon intensity should earn more credits.</td>
<td>For electricity used in fuel production, DEQ proposes to use statewide or regional average carbon intensities, due to workload issues. Ideally, DEQ could accommodate requests to individualized carbon intensities for production electricity. This would require substantial staff to accommodate requests from fuel producers.</td>
</tr>
<tr>
<td>Alternative 4: Electricity uses new resource electricity carbon intensity. <em>Arguments in favor — 1)</em> The carbon intensity for electricity should reflect only new generation power added to meet increased transportation electricity demand.</td>
<td>Gasoline and Diesel: Tracking the carbon intensity of individual fuel producers would be overly burdensome on regulated parties.</td>
</tr>
<tr>
<td>Alternative 5: For production of fuels, production facilities can use a carbon intensity which represents the actual electricity used in fuel production, rather than a state or regional average. <em>Arguments in favor — 1)</em> The electricity used by some fuel production facilities is lower in carbon intensity than the statewide average. This affects the carbon intensity of the finished fuel, which could be lower the carbon intensity of electricity used in fuel production is individual, rather than an average.</td>
<td></td>
</tr>
</tbody>
</table>
### 6b) Co-product credits *(See page 123 for details)*

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Refining biomass into fuels can produce economically viable co-products that can substitute for products that would otherwise have generated greenhouse gas emissions. The foregone greenhouse gas emissions from co-product use are subtracted from a fuel’s carbon intensity.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternatives Considered</td>
<td>Alternative 1: Ensure that if the carbon emission reductions of the co-product are attributed to the fuel carbon intensity, then there is no other way that they can market those reductions in the channels for the co-products. <em>Arguments in favor — 1) This would reduce double counting.</em></td>
</tr>
<tr>
<td>Rationale</td>
<td>Co-products produced with biofuels have economic value and displace greenhouse gas emissions that would have been generated from growing other crops, it is therefore appropriate to adjust carbon intensity values to account for co-products.</td>
</tr>
</tbody>
</table>

### 6c) Lifecycle analysis for fuel made from waste *(See page 128 for details)*

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Lifecycle assessment of the carbon intensity begins when the original product becomes waste. The lifecycle assessment of waste begins with its collection for use as a fuel, through refining, storage, transport, and use of the fuel. Nothing in the materials life prior to it becoming waste is included in the carbon intensity calculation.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rationale</td>
<td>This is consistent with how DEQ’s Solid Waste program views waste versus a feedstock.</td>
</tr>
</tbody>
</table>

### 6d) Lifecycle analysis for fuels made from biomass versus fuels made from petroleum products *(See page 129 for details)*

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Combustion of fuel made from biomass is assumed to have net zero carbon dioxide emissions. Combustion of fuel made from petroleum (including waste petroleum) is included in the lifecycle analysis.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternatives Considered</td>
<td>Alternative 1: This method of calculating emissions from biomass should include short life and waste biomass only. Biomass sources that grow on a short cycle are very different from trees grown on a 40-year or more cycle. <em>Arguments in favor — 1) This will alleviate the concern about “whole logs” as feedstock to fuels.</em></td>
</tr>
<tr>
<td>Rationale</td>
<td>Biomass fuel emissions: CO2 is pulled from the atmosphere as the plant grows. When the fuel is combusted, it returns the CO2 to the atmosphere, resulting in a net zero for CO2 emissions. When petroleum is combusted, it introduces new CO2 into the atmosphere, and these emissions are included in the carbon intensity.</td>
</tr>
</tbody>
</table>

### 6e) Models used on lifecycle analysis *(See page 129 for details)*

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>OR-GREET must be used to calculate carbon intensities used in the low carbon fuel standards. GREET was developed by Argonne National Lab, and calculates direct carbon intensity, including co-products. OR-GREET was adjusted using Oregon-specific inputs such as our electricity profile. GREET does not account for energy economy ratios.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternatives Considered</td>
<td>Alternative 1: Advisory committee members asked about using other transportation emission models. Alternative 2: Include a model that addresses the energy returned on energy-invested ratio.</td>
</tr>
</tbody>
</table>
### Arguments in favor — 1) Energy should not be wasted for lower emissions.

DEQ used GREET because it is a well-developed, publicly accessible model. Other models do not account for lifecycle greenhouse gas emissions.

### 6f) Indirect Land Use Change (See page 135 for details)

| DEQ Proposal | None included now. DEQ recognizes that indirect land use change effect is real, but that the calculation methodologies are still in development. DEQ intends to adjust the carbon intensity to include indirect land use change in the future as calculation methods improve. DEQ will review available calculation methods in 2014, and again in 2016 if necessary. When indirect land use change is included, DEQ will recalculate the 2010 baseline using carbon intensities adjusted for indirect land use change. At that time, DEQ will adjust any banked credits to account for indirect land use change. The result would be that a banked credit might be reduced some percentage, and a regulated or opt-in party would have less banked credits as a result. (See discussion on banked credits on page 87). Past compliance would not be affected. There would be some time period before the credits were adjusted. |
| Alternatives Considered | Alternative 1: Adjust carbon intensity with California Air Resources Board or EPA indirect land use change values. *Arguments in favor — 1) California Air Resources Board’s indirect land use change values are the most vetted.*

Alternative 2: Adjust carbon intensity with an average of carbon intensity values available.

*Arguments in favor — 1) It will be less of a change for participants in the low carbon fuel standards program to adjust an existing indirect land use change value than to add one in. Therefore, the average is a good choice.*

*Arguments in favor of both Alternatives 1 and 2: 1) Indirect land use change is real. Including it is the only way to accurately reflect the carbon intensity of fuels, 2) including some indirect land use change now would provide a correct signal to the market, and provide regulatory certainty 3) Not including indirect land use change is just as much of a decision as choosing one of the current methodologies. 4) Having indirect land use change in the rule from the beginning would favor lower carbon fuels faster. 5) The way California addressed indirect land use change allows for a smaller adjustment later. There is enough evidence that indirect land use change should be included. 6) There are real unintended consequences – it is not fair. 7) Fuels vulnerable to indirect land use change may oversell their product with fewer benefits while truly low carbon fuels that provide greater benefits are harmed. 8) Adding an indirect land use change value later on will disrupt the market.*

Alternative 3: Do not add indirect land use change values for biofuels without a corresponding indirect effect analysis and number for all fuels. *Arguments in favor — 1) All fuels have indirect effects 2) For fairness, it is important for indirect numbers for all fuels (including indirect land use change) to be added at the same time. 3) including indirect land use change and not other indirect effects disadvantages some fuels.*

Alternative 4: Include in rule that indirect land use change will be included in 2014.

*Arguments in favor — 1) If a firm date is not in rule, this could be delayed.*

| Rationale | Calculating indirect land use change is a nascent field with data acquisition and analysis rapidly advancing. DEQ’s contractor recommended adjusting carbon intensity values for indirect land use change later when the field has matured. Reference TIAZ analysis on variation in numbers. |
### 6g) Other indirect effects

*(See page 138 for details)*

| **DEQ Proposal** | None included now. Review science in 2014, and in 2016. Recalculate baseline as above when any new indirect effects are added to the low carbon fuel standards program. Indirect effects occur as a result of fuel production. Examples include impacts on water quality or quantity, habitat, and military emissions. When indirect effects are included, DEQ will recalculate the 2010 baseline using carbon intensities adjusted for indirect effects. At that time, DEQ will adjust any banked credits to account for indirect effects. The result would be that a banked credit might be reduced some percentage, and a regulated or opt-in party would have less banked credits as a result. (See discussion on banked credits on page 87). Past compliance would not be affected. There would be some time period before the credits were adjusted. |
| **Alternatives Considered** | Alternative 1: Do not consider adjusting carbon intensity values to account for any indirect effects. *Arguments in favor — 1) Indirect effects other than indirect land use change are too difficult to quantify.*  
Alternative 2: Adjust carbon intensity values to account for indirect effects now. *Arguments in favor — 1) all fuels have indirect effects. The indirect effects of petroleum fuels should be considered. 2) It is unwise and scientifically unjustified to burden one fuel with an indirect impact (indirect land use change) if we are not burdening other fuels with their specific market mediated impact.*  
Alternative 3: Include the emissions from the military’s equipment to protect the transport of oil from the Middle East. *Arguments in favor – 1) Indirect effects should apply to petroleum fuels consistently with biomass-based fuels.* |
| **Rationale** | DEQ is not adjusting carbon intensity values to account for indirect effects at this time because the science of quantifying indirect effects is still in development. After receiving many advisory committee comments on this issue, DEQ will consider including indirect effects when the calculation methodologies are sufficient. Indirect effects could be added separately from indirect land use change, depending on the adequacy of the science. |

### 6h) Energy Economy Ratios (Drive Train Efficiencies)

*(See page 139 for details)*

| **DEQ Proposal** | *Energy Economy Ratio (EER) for light duty:* based on CA vehicle fuel economy research (but uses different methodology to account for future fuel economy). The EERs for electric and hydrogen vehicles are adjusted in future years to account for the required fuel economy improvements in gasoline passenger light-duty vehicles.  
- Electricity: 4.1 declining to 3.1 in 2022  
- Hydrogen: 3.0 declining to 2.3 in 2022  
- CNG: 1.0  

*EER for heavy duty:* (OR vehicle definitions in rule only include light and heavy duty) based on CA vehicle fuel economy research, although the CNG/LNG EER has been adjusted from CA’s.  
- Electricity: 2.7  
- Hydrogen: 1.9  
- CNG/LNG: 0.94. |
Since EPA’s new fuel economy requirements will start with model year 2014 for heavy-duty vehicles, DEQ proposes to update the EERs in 2014. At that time, DEQ will also review the EER for heavy-duty LNG based on new vehicle technology, as well as the EER for all alternative vehicle types, and will look at improvements in the fuel economy for conventional as well as alternative vehicles.

**Alternatives Considered**

**Alternative 1:** Use California Air Resources Board (CARB) method for electricity and hydrogen light-duty EER. *Arguments in favor — 1) Consistency with California low carbon fuel standards. 2) The EER for the next new vehicles will be California Air Resources Board’s EERs.*

**Alternative 2:** Use California Air Resources Board (CARB) EER for CNG/LNG. *Arguments in favor — 1) Consistency with California*

DEQ staff propose to base EERs for Oregon on California Air Resources Board research with two exceptions:

- **Light duty gasoline vehicles.** Because the EER of an electric vehicle today is 4.1 compared to a gasoline vehicle, 4.1 are the EER we will use today. But as light duty vehicles become more fuel efficient, the EER will decline to 3.1, and DEQ proposes to use that value in 2022.
- **CNG/LNG heavy-duty.** Oregon does not have as large a legacy fleet as CA does.

DEQ also added in a 2014 update to EERs based on EPA’s proposed heavy-duty fuel economy improvements. Light duty EERs will also be reviewed at that time.

### 7) Updating or Adding to the Carbon Intensity Lookup Table

#### 7a) Updating Existing Carbon Intensity in Lookup Table (See page 79 for details)

**DEQ Proposal**

For gasoline, diesel, electricity, and fossil CNG from a pipeline from North American sources:

Update the carbon intensity of all fuels with statewide average carbon intensities every 3 years at a minimum. If the statewide average changes by more than 5gCO2e/MJ or 10 percent, DEQ will update the statewide average carbon intensity.

Individual producers of these fuels must use the statewide average listed in the carbon intensity lookup table (i.e. no individual carbon intensity numbers.)

**Alternatives Considered**

**Alternative 1:** Update carbon intensities more often than every three years. *Arguments in favor — 1) Keeps the carbon intensity lookup table more accurate. In addition, if a carbon intensity changes, emission reductions could be lost.*

**Rationale**

Statewide carbon intensities are not expected to change drastically each year. However, if there is a significant change, DEQ is not precluded from updating carbon intensities more frequently. Therefore, updating statewide carbon intensities at a minimum every three years will keep the carbon intensity lookup table up to date.

#### 7b) Adding a New Carbon Intensity to the Lookup Table (New Fuel Pathway Process) (See page 79 for details)

**DEQ Proposal**

For ethanol, biomass-based diesel, LNG, Biogas (CNG and LNG), hydrogen, or any new fuel:
There are two situations in which a new carbon intensity can be added to the carbon intensity lookup table:

1) Any new fuel or new feedstock must obtain a new carbon intensity using OR GREET.

2) For a new and improved process, both of the following two thresholds must be met to get a new carbon intensity number:
   a) **Minimum Thresholds for Changes in Carbon Intensity:** The carbon intensity of the new process, compared to the existing process for the same fuel-feedstock combination in the lookup table, changes more than 5.0 g CO2E/MJ or 10 percent of the carbon intensity in the lookup table, whichever is less; **AND**
   b) **Minimum Fuel Volume Thresholds:** The regulated party is able and intends to provide more than one million gasoline gallon equivalents per year of the fuel in Oregon. (The second criterion does not apply if all providers of that fuel supply less than one million gasoline gallon equivalents per year in total.)

If a fuel producer’s process changes so that the carbon intensity increases by more than 5.0 g CO2E/MJ or 10 percent, the fuel producer must notify DEQ and obtain a new carbon intensity.

**Alternatives Considered**

- **Alternative 1:** If the carbon intensity improves more than 5.0 g CO2E/MJ, allow a carbon intensity to be added to table. *Arguments in favor — 1) Consistency with California.*

- **Alternative 2:** Adding a carbon intensity at a producer’s request. *An argument in favor — 1) For funding purposes, a pilot-scale producer needs to be able to get a carbon intensity number for their commercial-scale facility.*

**Rationale**

DEQ proposal for adding new carbon intensities to the lookup table will encourage and reward innovation and ensure that the carbon intensity lookup table accurately reflects current fuels sold in Oregon.

In order to manage the workload for evaluating and approving applications, DEQ set minimum thresholds to ensure that the new carbon intensity to be added to the table is significantly different, and to ensure that commercial quantities of fuel will be supplied in Oregon to make the effort worthwhile.

DEQ believes that the hybrid approach of allowing a new carbon intensity to be added with either a 5.0 g CO2E/MJ or 10 percent change in carbon intensity (whichever is less) is fairer than either setting a single value threshold or setting a straight percentage threshold.

After advisory committee comment, DEQ added a provision that if carbon intensity increases a certain amount a fuel producer needs to notify DEQ and get a new carbon intensity.

**7c) High Carbon Intensity Crudes** *(See page 82 for details)*

**DEQ Proposal**

DEQ proposes to update the carbon intensity values lookup table for gasoline and diesel a minimum of every 3 years to reflect the “current” state of petroleum crudes. This will account for any increased amounts of high carbon intensity crudes from existing areas as well as any new high carbon intensity crude sources.

**Alternatives Considered**

- **Alternative 1:** Always use carbon intensity in lookup table for petroleum crudes. *Arguments in favor — 1) This alternative is the least administratively burdensome, and provides the most regulatory certainty. 2) All crude should be treated equally. 3) This
alternative does not cause crude shuffling.

Alternative 2: Fuel producer adds a new carbon intensity to lookup table for any fuel produced from high carbon intensity crude oils. Arguments in favor — 1) Fair method of accounting for increase in carbon intensity due to crude sources used in fuel production. 2) Provides more regulatory certainty. 3) Other alternatives do not have any incentive for an individual company to avoid new use of high carbon intensity crudes. 4) Crude shuffling is not likely in Oregon because we are a small part of the market.

Alternative 3: Use California Air Resources Board’s method. [Note: DEQ considered this alternative, but did not present it to the advisory committee because it is extremely complex and administratively resource intensive] Arguments in favor — 1) This accounts for carbon intensity as accurately as DEQ’s proposal does, but holds individual fuel producers responsible for use of high carbon intensity crudes instead of accounting for high carbon intensity crudes with a statewide average. 2) Consistency with California. 3) Crude shuffling is not a likely result of Oregon’s low carbon fuel standards because Oregon is a small part of the regional petroleum market. 4) Environmental integrity and efficacy of program. 5) This alternative treats petroleum the way the biofuels are treated in requiring a new carbon intensity for fuels that are significantly different; fuels should be treated consistently.

Alternative 4: Update carbon intensity for gasoline and diesel more frequently than every 3 years. Arguments in favor — 1) This would keep the table more accurate and ensure that carbon intensity reductions are obtained. 2) Reports suggest that tar sand production might ramp up quickly. 3) Environmental integrity and efficacy of program. 4) Low carbon fuel producers need to know how large the market will be from year to year. 4) If high carbon intensity crudes are not tracked carefully, there is a potential that low carbon fuel standards will lose ground in meeting carbon intensity goals.

Rationale

Accurately accounts for increases (or decreases) in carbon intensity in gasoline and diesel fuels with a minimum of administrative burden. If carbon intensities change drastically, DEQ could update them more frequently, but would not be bound to make updates more frequently for small changes in carbon intensity. Ideally, DEQ would update more frequently than every three years if needed, DEQ’s proposal will not encourage crude shuffling as much as alternatives 2 or 3 would.

8) Credits and Deficits *(See page 83 for details)*

- Credits are not personal property, they are a regulatory implement.
- Credits cannot be “borrowed” against future emission reductions. Rationale: DEQ does not have a reliable way to ensure that reductions from borrowed credits will be achieved.
- Only regulated or opt-in parties can buy credits. Rationale: Avoids third party speculation in the credit market.
- No carbon credits from other programs can be used for the low carbon fuel program. Rationale: This is intended to ensure that greenhouse gas reductions are achieved within the transportation sector and to stimulate the use of low-carbon intensity fuels.
- Deficits are generated when a high carbon intensity fuel is first produced or imported into Oregon. Fuel volumes sold to out of state users will be deducted from the regulated party’s compliance obligation for the imported fuel. The deduction relies on
appropriate documentation of the fuel export. Rationale: This will include all appropriate fuel in the low carbon fuel standards.

- Credits can be sold once the fuel is supplied to a retail facility or end user in Oregon. The opt-in or regulated party reporting a credit would need to possess documentation that the fuel was supplied to a retail facility or end user in Oregon. Rationale: DEQ proposes this is the best way to ensure that credits sold or banked are actually valid.
- Alternatives considered: Same methodology as CA. Arguments in favor — 1) easier for regulated and opt-in parties to report the same way in both CA and OR.

### 8a) Low carbon fuel credit banking

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Credits can be banked indefinitely without expiration. At a future date, DEQ will adjust the carbon intensity to account for indirect land use change for biofuels produced from crops. At that time, DEQ will adjust any banked credits generated using biofuels made from crops accordingly.</th>
</tr>
</thead>
</table>
| Alternatives Considered | **Alternative 1:** No banking of credits.  
**Alternative 2:** Credits expire after a certain number of years.  
Arguments in favor of alternatives 1 and 2: 1) Credit banking could dilute the program in later years if a big credit surplus builds up. 2) With unlimited credit banking, a regulated party could hoard credits.  
**Alternative 3:** No banked credits until indirect land use change is added. |
| Rationale | Credit banking will permit fuel providers to achieve early reductions under the program and allow greater flexibility in managing compliance in coming years. The ability to carry credits forward should also improve the stability of the credit market, as the value of credits would not expire within the year. |

### 8b) Small low carbon fuel deficits

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
<th>Small deficits can be carried over to the following year. “Small” deficit is a deficit remaining at the end of a compliance year that is 10 percent or less than the total deficits generated by that regulated party during the compliance year. Small deficits must be reconciled the following compliance year. During the last year of the program, no credit carryover would be allowed.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rationale</td>
<td>Allows some flexibility for regulated parties without compromising the integrity of the program, and this flexibility could contribute toward minimizing compliance costs for regulated parties.</td>
</tr>
</tbody>
</table>

### 8c) How would fuel sold to exempt users be excluded from credit and deficit calculations?

| DEQ Proposal | If a regulated party sells a delivery (e.g., a quantity of fuel on a single invoice or bill of lading, etc., or a delivery of blended fuel, regardless of how many invoices there are for that delivery) of fuels to an exempt user, the regulated party has two options for calculating credits and deficits for that delivery of fuel during the compliance period:  
- Exclude that entire delivery of fuel from credit and deficit calculations. |

### Alternatives Considered

**Alternative 1: Do not allow credit for any fuel sold to exempt fuel uses.** *Arguments in favor — 1) Some exempt users are worried about blended biofuels.*

### Rationale

Some exempt fuel users already use biofuels. The low carbon fuel standards need to remain neutral as far as low carbon fuels and exempt uses, and make sure there is not an incentive created to sell more or less low carbon fuel to exempt uses. In addition, the low carbon fuel standard is not a requirement for fuel blending.

### 8d) Can low carbon fuel credits still accrue during exemptions or deferrals? *(See page 91 for details)*

<table>
<thead>
<tr>
<th><strong>DEQ Proposal</strong></th>
<th>Yes. Credits can accrue during exemption or deferral periods.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Alternatives Considered</strong></td>
<td>Alternative 1: Credits cannot accrue during deferral periods.</td>
</tr>
<tr>
<td><strong>Rationale</strong></td>
<td>The use of exemptions or deferrals most likely indicates a limited supply of low carbon fuels to meet the demand. Allowing credits to accrue during times of exemptions and deferrals may be helpful to address a scarcity of low carbon fuels and provide additional ways to comply with the low carbon fuel standards.</td>
</tr>
<tr>
<td><strong>Rationale</strong></td>
<td>Allowing credits to accrue during times of exemptions or deferrals provides more regulatory certainty for investors in low carbon fuels.</td>
</tr>
</tbody>
</table>

### 8e) Buying and Selling Credits *(See page 91 for details)*

<table>
<thead>
<tr>
<th><strong>DEQ Proposal</strong></th>
<th>At the end of the compliance year, DEQ will compare credits bought with credits sold based on annual compliance reports, and at that time, could make aggregated information on credits available to regulated and opt-in parties.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>DEQ will maintain a list of regulated and opt-in parties, and for fuel producers, the total credit generation capacity of each production plant.</td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>If a regulated or opt-in party sells a credit that is invalid, the credit seller will need to provide valid credit to make up for the invalid one, and will be subject to enforcement.</td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>DEQ will not take enforcement action against the credit buyer, provided they had verified:</td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>1. That the credit seller was on DEQ’s regulated/opt-in party list,</td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>2. The carbon intensity of the fuel from that producer matches the carbon intensity for that fuel producer on DEQ’s website; and</td>
</tr>
<tr>
<td><strong>DEQ Proposal</strong></td>
<td>3. For credits bought from biofuels producers, the number of credits purchased did not exceed the credit generation capacity of each the seller’s production plant, as reported.</td>
</tr>
<tr>
<td><strong>Alternatives Considered</strong></td>
<td>Credits would not be verified by DEQ prior to sale.</td>
</tr>
<tr>
<td><strong>Alternative 1:</strong></td>
<td>DEQ verifies credits prior to sale (voluntary or mandatory). <em>Arguments in favor — 1) Provides more certainty to a buyer of a credit. 2) Regulated parties will not purchase unverified credits.</em></td>
</tr>
</tbody>
</table>
| **Alternative 2:** | DEQ provides more information during the year to increase the transparency of the credit market. *Arguments in favor — 1) A more transparent reporting system could lead to a better functioning, more responsive market, and regulated and
opt-in parties would have information on current low carbon fuel credit prices and parties with available credits for sale.

Alternative 3: DEQ facilitates credit sales. *Arguments in favor — 1) More transparency for credit market.*

Alternative 4: Place a price cap on credits. *Arguments in favor — 1) This would take away the incentive to horde credits.*

DEQ’s proposal for buying and selling credits ensures that credit sellers are held responsible for invalid credits, which should provide certainty for credit purchasers. Verification of credits prior to sale could be time consuming and hinder the sale of credits.

This structure for a credit market has the least amount of administrative burden on DEQ and regulated and opt-in parties compared to other options that the advisory committee discussed. This is the least complex of the options, and the easiest to implement. Under this proposal, there will be fewer barriers to buying and selling credits because DEQ will not need to participate in the sale or purchase of credits. DEQ’s proposal could decrease compliance costs compared to the alternatives.

### 9) Temporary Fuel Supply Deferrals

#### 9a) Process for Determining whether to issue a Temporary Fuel Supply Deferral *(See page 94 for details)*

**DEQ Proposal**

When notified of a disruption, DEQ will use the volume, carbon intensity, and expected duration of the disruption to calculate lost credits. When more than five percent (5 percent) of the total aggregate number of credits used to meet the low carbon fuel standards in the previous calendar year are lost, DEQ will investigate whether a deferral is needed, considering:

- Availability and carbon intensity of low carbon fuels from other sources;
- Availability of banked low carbon fuel credits;
- Range of impact: Broad impact on a number of regulated parties or narrow impact on just a few regulated parties?
- Magnitude of impact on individual and collective regulated parties.

When enacted, deferrals apply to either gasoline or diesel (or their respective substitutes), not a particular regulated party. If the disruption ends, or if other low carbon fuels become available, DEQ will end the deferral period.

**Alternatives Considered**

**Alternative 1:** The advisory committee discussed credit disruptions in the range of 5-25 percent.

**Alternative 2:** A threshold, below which DEQ would not be able to issue deferrals.

**Alternative 3:** No temporary deferrals included. *Arguments in favor — 1) Having provisions for fuel supply deferrals creates uncertainty and risk for low carbon fuel providers and favors regulated parties.*
### Rationale

The authorizing statute requires deferrals for adequate fuel supply.

5 percent of credits lost is a conservative early warning threshold because regulated parties will be able to carry over 10 percent of deficits as a “small deficit” (see page 88). DEQ determined that a threshold below which DEQ would not be able to issue deferrals was arbitrary and unnecessary.

A conservative warning level is important for two reasons: 1) fuel supply deferrals protect regulated parties from fuel supply shortages beyond their control and 2) even a 5 percent credit shortage can seriously impact some regulated parties.

Although the threshold for investigation needs to be low, DEQ needs to be careful not to issue unnecessary deferrals. Excessive use of deferrals could penalize early actors, act as a disincentive to investments in low carbon fuels, and may inhibit or prolong the growth of alternative fuels production and use.

### 9b) Compliance Adjustments for Temporary Fuel Supply Deferral

*(See page 98 for details)*

**DEQ Proposal**

DEQ can make compliance adjustments for administratively-issued temporary fuel supply deferrals in two ways:

- **Temporary Fuel Supply Deferral Type 1**: Deficits generated during a temporary deferral period can be carried over and paid back within one to three years from the year in which the deferral period occurred.
- **Temporary Fuel Supply Deferral Type 2**: During the deferral period, no deficits would accrue for the fuel type for which the deferral has been issued.

**Alternatives Considered**

- *Alternative 1*: DEQ also considered “long-term deferrals”, but has abandoned this idea since extended fuel supply shortages are better covered under “forecasted fuel supply deferrals.”
- *Alternative 2*: DEQ considered setting an “alternate standard” but has abandoned this idea as overly complex.
- *Alternative 3*: Fuel price should be considered in fuel supply deferrals.

**Rationale**

Because the magnitude, effect, and consequences of fuel supply shortages could vary, it is important to have a variety of options available to allow DEQ to address different situations.

### 10) Forecasted Fuel Supply Deferrals

**10a) Process for Determining whether to issue a Forecasted Fuel Supply Deferral** *(See page 96 for details)*

**DEQ Proposal**

DEQ, in consultation with Oregon Dept. of Energy (ODOE), will annually project low carbon fuel volumes for the following year considering:

- Trends in alternative fuel transportation use;
- The status of existing and planned alternative fuel production facilities;
- Planned projects such as electric vehicle charging or CNG fuel stations;
- RFS2 volumes for advanced biofuels and biomass-based diesel;
- Updates to the carbon intensities of fuels (if applicable);
• Banked credits; and
• Projected total fuel consumption volumes, including gasoline and diesel.

DEQ will use fuel volume projections to calculate the carbon intensity of Oregon’s fuel supply for the following year, and compare total credits available with credits needed for that year. If the credits available are 5 percent less than the credits needed for that year, DEQ and ODOE may begin an investigation to evaluate whether or not sufficient volumes and carbon intensities of low carbon fuels will be available in the future to assure compliance with the standard.

DEQ might also forecast more than one year out, particularly for years where the reduction is larger.

<table>
<thead>
<tr>
<th>Alternatives Considered</th>
</tr>
</thead>
</table>
| **Alternative 1:** If the projected volume and carbon intensity of transportation fuel in Oregon for a future year exceeds the low carbon fuel standards for that future year by 0.1 percent or more, DEQ and ODOE may begin an investigation to evaluate whether or not sufficient volumes and carbon intensities of low carbon fuels will be available in the future to assure compliance with the standard. *Arguments in favor — 1) A 0.1 percent significance threshold, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5 percent confidence interval.*

| **Alternative 2:** Account for the 10 percent small deficit carryover needs to be accounted for in this calculation. *Arguments in favor — 1) Because regulated parties will be able to carry over 10 percent of deficits, a 5 percent significance threshold is too low.*

<table>
<thead>
<tr>
<th>Rationale</th>
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</thead>
<tbody>
<tr>
<td>Forecasting available supplies of low carbon fuels can assist DEQ to evaluate the feasibility of the low carbon fuel standard in the following year. It is important to have a conservative investigation level to protect regulated parties from fuel supply shortages beyond their control. If the difference between the forecasted and required credits is greater than the significance threshold, that does not guarantee a deferral, but will initiate an investigation to determine if deferrals are needed. The 10 percent small deficit carryover is intended to provide flexibility for regulated parties and should not be included in the calculation of the significance threshold.</td>
</tr>
</tbody>
</table>

**10b) Compliance Adjustments for Forecasted Fuel Supply Deferral (See page 99 for details)**

<table>
<thead>
<tr>
<th>DEQ Proposal</th>
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</thead>
<tbody>
<tr>
<td>When issuing a forecasted deferral, DEQ will have two deferral types to choose from: <strong>Forecasts Fuel Supply Deferral Type 1:</strong> Administratively defer the standard for one week to a year (no rulemaking, administrative only, no lasting change to compliance curve or horizon year). <strong>Forecasts Fuel Supply Deferral Type 2:</strong> Revise the low carbon fuel standard for subsequent years; rulemaking required. Either: • Revise the low carbon fuel standards; OR • Revise the low carbon fuel standards and extend the program beyond the horizon year (2022). For Type 2 Forecasted Fuel Supply Deferrals, DEQ proposes to use a temporary rulemaking process to revise the standard for the following year expeditiously, followed by a traditional rulemaking process to permanently revise the overall compliance schedule.</td>
</tr>
</tbody>
</table>
Considered Alternative 1: Include another alternative where reductions could be made up in future years. *Arguments in favor — 1) Whenever possible, DEQ should make up for reductions lost in deferrals.*

Because the magnitude, effect, and consequences of fuel supply shortages could vary, it is important to have a variety of options available to allow DEQ to address different situations. Allowing an administrative fix that does not have lasting change on the compliance curve or horizon year is an important option.

### 11) Consumer Cost Safety Net

#### 11a) Process for determining whether exemptions or deferrals are necessary for price *(See page 101 for details)*

When the 12-month rolling average price of gasoline or diesel is more than 5 percent above the 12-month rolling average price of gasoline or diesel in the statutory PADD-5, an investigation leading to an Environmental Quality Commission determination of whether or not exemptions and deferrals are necessary is triggered. DEQ proposes to use U.S. Energy Information Administration (EIA) data on the statutory PADD-5 for gasoline, and on the actual PADD-5 for diesel to track this issue.

Any outside entity can let DEQ know an investigation is needed, based on EIA data, or credible data from some other source.

In order to trigger an exemption or deferral, the Environmental Quality Commission would have to find that the cause of the non-competitive Oregon gasoline or diesel price is attributable to the low carbon fuel standards, and not some other factor, and that action is necessary to mitigate the non-competitive price.

**DEQ Proposal**

Other causal factors:
- Faulty or incomplete fuel volume and price data;
- Natural or manmade disasters affecting the fuel supply to Oregon, but not one of the other states (Washington, Arizona or Nevada);
- Crude oil prices in Alaska and sources of Oregon’s crude vs. crude prices for fuel supplied to Arizona and Nevada;
- Seasonal demands or unusual demands (for example, the Olympic games);
- A change in environmental regulations that affects Oregon, but not Washington, Arizona or Nevada;
- Arizona discontinues its use of reformulated gasoline;
- An increase in population or demand for fuel; and
- A decrease in retail outlets for fuel.

#### Alternatives Considered

**Alternative 1**: Using Oil Price Information Service or other data. *Arguments in favor — 1) No time lag.*

**Alternative 2**: Define a non-competitive price as 1 percent - 4.9 percent. *Arguments in*  

---

\(i\) Please note that the actual PADD-5 is different from the HB 2186-defined statutory PADD-5. For the purposes of Oregon low carbon fuel standards, the legislature has defined PADD-5 as only including the states of Oregon, Washington, Nevada and Arizona.
favor — 1) We need to protect consumers from any price increases due to the low carbon fuel standards.

Alternative 3 Define a non-competitive price as 10 percent. Arguments in favor — 1) A low threshold for price variability does not encourage substitution. A higher range of allowed price impact would encourage substitution at a higher rate, potentially resulting in stabilization at a lower price later on. A 10 percent difference might be more appropriate for a trigger than 5 percent. 2) It is important not to mask the effect of the low carbon fuel standards.

Alternative 4: Issue exemptions and deferrals administratively, instead of waiting for the Environmental Quality Commission to make a finding. Arguments in favor — 1) Time will be critical in addressing any non-competitive price.

Alternative 5: No price deferrals included. Arguments in favor — 1) Having provisions for fuel supply deferrals creates uncertainty and risk for low carbon fuel providers and favors regulated parties.

Rationale

EIA is the most accurate volume-weighted price data. EIA data does not contain taxes, which some committee members felt was important. DEQ will accept other data if EIA data is not available.

The authorizing statute requires the inclusion of deferrals when the low carbon fuel standard causes a non-competitive 12-month rolling average price of gasoline or diesel in Oregon as compared to other states. With regard to the non-competitive price, the trigger needs to be high enough to account for normal fluctuation in gasoline and diesel prices, so that an investigation would not be triggered unnecessarily. It also needs to be low enough so that it would capture any impacts from a low carbon fuel standards early on. Because Oregon’s 12-month rolling average weighted price of gasoline has not gone over 5 percent above the 12-month rolling weighted average price of gasoline in the statutory PADD-5 during the past 10 years, 5 percent is deemed to be adequate for satisfying the above criteria.

Because the statute requires the Environmental Quality Commission to make a finding, it is unlikely that authority will be delegated to DEQ. In addition, because the exemptions and deferrals are for 12-month rolling weighted average, the problem will be building for several months, and DEQ can track it and be prepared with a response.

11b) Compliance Adjustment for Consumer Cost Safety Net (Price of fuel) (See page 101 for details)

DEQ Proposal

The exemptions or deferrals would apply to either:

- Gasoline and any gasoline substitutes with a carbon intensity equal to or higher than gasoline; OR
- Diesel and any diesel substitutes with a carbon intensity equal to or higher than diesel

Compliance adjustments include:

1. Allow regulated parties to carry over large deficits and pay them back over the following one to three years; OR
2. Exempt a fuel type from the low carbon fuel standard for up to one year (no deficits accrue during exemption), OR
3. Defer the low carbon fuel standard for up to one year, OR
4. Exempt a percentage of either gasoline or diesel fuels from the low carbon fuel standard for up to one year

Credits can still accrue for during exemptions.

If Oregon’s 12-month rolling weighted average price goes over 5 percent, and the Environmental Quality Commission finds that the cause is not the low carbon fuel standards, then DEQ reserves the right to re-investigate whether exemptions and deferrals are warranted when one of the causal factors listed above changes.

The statute requires the Environmental Quality Commission to issue a finding of the cause of non-competitive price. Because the cause could vary, it is important to have a variety of options available to allow the Environmental Quality Commission to address different situations.

12) Recordkeeping and Reporting *(See page 109 for details)*

For alternative fuel volumes such as CNG, LNG, hydrogen, or electricity, if there is a sub-meter on the fuel dispenser, the opt-in or regulated party must use that for fuel volume reporting. If there is no sub-meter on the fuel dispensing equipment, the regulated or opt-in party may report the amount of fuel dispensed using any other method that is substantially similar to or better than the use of sub-meters (as determined by DEQ). DEQ will consider requiring sub-metering in the 2014 and 2016 reviews.

**Recordkeeping** – to be maintained by the regulated party at its facility:

Each delivery:
- Volume of each fuel provided;
- Volume of each fuel provided to an exempt user; and
- Carbon intensity of each fuel provided that is not exempt.

Credits sold or bought: seller, buyer, price, number of credits, and date of transaction.

Where the compliance obligation is transferred or retained via written contract, copy of the contract.

**DEQ Proposal**

Quarterly carbon intensity calculation:
- The volume of each fuel provided;
- The calculated carbon intensity of each fuel provided;
- Emission credits that are acquired, sold, or banked for future use; and
- The volume of fuel that is exempt from the low carbon fuel standard.

**Reporting** – to be submitted to the agency

Initial physical fuel route report:
- Country of origin
- The physical routes (truck, rail, pipeline, etc.) by which a fuel is transported or distributed from its point of production through any intermediaries to the fuel blender, producer, importer or provider;
- Carbon intensity of the pathway using OR-GREET;
- Evidence of fuel entering a physical route;
- Total amount of fuel available from route; and
- Evidence of an equal amount of fuel being removed from a fuel route. (i.e. bought by a regulated party)
## Alternatives Considered

<table>
<thead>
<tr>
<th>Alternative</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revision to physical fuel route report</strong> (as needed)</td>
<td>Revisions to physical fuel route report when conditions change.</td>
</tr>
<tr>
<td><strong>Annual report</strong></td>
<td>Total credits carried over from the previous year; Total deficits carried over from the previous year; All credits acquired or sold for each credit transaction; Total credits generated in the current year; Total deficits generated in the current year; Total credits to be carried over to the next year; and Total deficits to be carried over to the next year.</td>
</tr>
</tbody>
</table>

Regulated or opt-in parties submitting reports might request information be exempt from disclosure under ORS 192.410-505.

| **Alternative 1:** Quarterly reporting | *Arguments in favor — 1)* Quarterly reporting would help regulated parties know their status with the low carbon fuel standards and whether they needed more credits to meet the standards. |
| **Alternative 2:** Quarterly compliance with low carbon fuel standards | *Arguments in favor — 1)* Quarterly compliance for the low carbon fuel standards would ensure credits are sold throughout the year, instead of mostly toward the end of the year. |

**Align low carbon fuel standards reporting with one of the following existing programs:**

- **Alternative 3:** Oregon Department of Transportation’s fuel tax reporting.
- **Alternative 4:** DEQ’s greenhouse gas reporting rule Phase II.
- **Alternative 5:** DEQ’s air quality permitting program for industrial emissions, which includes DEQ’s reporting requirements for bulk gasoline plants and gasoline dispensing facilities.
- **Alternative 6:** CA reporting 1) consistency with CA and ease for regulated parties in both states 2) could use their web tool 3) |

**Arguments in favor of alternatives 3-6 — 1)* Streamlining reporting requirements.**

## Rationale

It is necessary to track the carbon intensity of specific fuels in order to determine whether a regulated facility has met their compliance obligation.

DEQ originally proposed quarterly reporting. DEQ’s proposal has been modified to include a combination of recordkeeping and reporting requirements to provide the documentation needs of this regulatory program while attempting to minimize the amount of oversight needed by DEQ. In addition, keeping reporting simple will encourage opt-in parties to participate. See credit selling and buying section for discussion of transparency of market.

The first year of the program requires reporting only; compliance with carbon intensity standards begins with the second year of the program. This approach provides a transitional period in which affected parties can become familiar with the reporting systems.

Consistency with ODOT fuels tax and DEQ greenhouse gas reporting rules was an important consideration in choosing regulated parties. DEQ’s research and discussion with stakeholders showed that the regulated party for the low carbon fuel standards needs
to be different from the entities regulated under ODOT fuels tax, DEQ greenhouse gas reporting rules, or DEQ permits. For a discussion, please see section on regulated parties for gasoline, diesel and biofuels on page 57.

Several committee members expressed their support for using an adapted version of California’s web-based reporting tool.

### 13) Enforcement (See page 112 for details)

| **DEQ Proposal** | Regulated or Opt-In parties could have the following kinds of violations:  
| o Failure to submit a report  
| o Failure to maintain records  
| o Falsification of information on a report  
| o Failure to apply for a new fuel pathway when the carbon intensity increases  
| o Failure to comply with the low carbon fuel standard  
| o Selling an invalid credit |

DEQ’s enforcement rules are in Oregon Administrative Rules Division 12 and is periodically updated. Initially, DEQ is not proposing any changes to Division 12 specific to implementing a LCFS. Existing guidance on enforcement of general air quality violations will apply. When the next update occurs, DEQ intends to incorporate LCFS-specific enforcement actions.

| **Alternatives Considered** | Alternative 1: Develop draft rules and guidance for Division 12 with the development of the LCFS draft rules. *Arguments in favor* — Since not all violations listed above are considered in existing enforcement rules, there can be unintended inconsistencies in how the general enforcement guidance would apply to specific violations. |

As proposed, 2012 is a reporting-only year for the LCFS. Any regulated or opt-in party failing to submit a report in this year will be addressed through additional technical assistance rather than enforcement. 2013 will be the first compliance year, making the first annual report due in Spring 2014. By then, DEQ will update the Division 12 rule to incorporate LCFS-specific language.

| **Rationale** |

### 14) Review of Rule (See page 117 for details)

- **As needed:** Exemptions and deferrals, consumer cost safety net, implementation of the rule, fuel quality and reliability, compliance issues.

- **Annual:** LCFS targets, availability of low carbon fuels, rates of commercialization of fuels and vehicles. (DEQ reports any significant issues to the Environmental Quality Commission.)

- **2014 Review (late 2013 or early 2014):** Incorporate any advances in indirect land use change or other indirect effects, explore consistency with Washington State if Washington pursues a low carbon fuel standard, update energy economy ratios (EERs), explore the possibility of allowing credit trades with other states, and to review California Air Resources Board updates for relevancy. (DEQ reports any significant issues to the Environmental Quality Commission.)

- **Comprehensive 2016 Program Review:** All above, plus requirements for measuring electricity use by vehicles, review of which electrification activities qualify for credits, adjustments to compliance schedule, identification of hurdles or barriers to increasing use and supplies of low carbon fuels. DEQ proposes to evaluate...
Any proposed changes to the LCFS rule would require formal rulemaking, including a public review and comment period and adoption by the Environmental Quality Commission.

If a federal LCFS were adopted, DEQ would need to revisit the Oregon LCFS.

### Alternatives Considered

<table>
<thead>
<tr>
<th>Alternative 1: No 2014 review. Arguments in favor — 1) DEQ initially did not propose a 2014 review. But after advisory committee members commented that a review prior to 2016 is necessary to address indirect land use change and other indirect effects, energy economy ratios, LCFS in neighboring states, as well as other issues, DEQ added in a 2014 review.</th>
</tr>
</thead>
</table>

### Rationale

DEQ investigated administrative updates to the rule at the advisory committee’s request. However, due to Oregon’s rulemaking laws, any changes to the rule could not be done administratively, and would need to involve rulemaking.

The advisory committee requested, and DEQ agrees that if federal low carbon fuel standards were adopted, DEQ would need to revisit Oregon’s standards.
III. House Bill 2186 Roadmap

Key Aspects of House Bill 2186 and corresponding low carbon fuel standards element

<table>
<thead>
<tr>
<th>House Bill 2186 reference</th>
<th>Program element required by statute</th>
<th>Relevant Report Section</th>
<th>Page Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Section 6 (2)(b)(A)</td>
<td>A schedule to phase in implementation of the standards in a manner that reduces the average amount of greenhouse gas emissions per unit of fuel energy of the fuels by 10 percent below 2010 levels by the year 2020</td>
<td>VI. 5. Low Carbon Fuel Standards Compliance Schedule</td>
<td>Page 72</td>
</tr>
<tr>
<td>Section 6 (2)(b)(B)</td>
<td>Standards for greenhouse gas emissions attributable to the fuels throughout their lifecycles, including but not limited to emissions from the production, storage, transportation and combustion of the fuels and from changes in land use associated with the fuels</td>
<td>VI. 5. Low Carbon Fuel Standards Compliance Schedule VII. Calculating Carbon Intensities for Oregon Transportation Fuels</td>
<td>Page 72 Page 122</td>
</tr>
<tr>
<td>Section 6 (2)(b)(C)</td>
<td>Provisions allowing the use of all types of low carbon fuels to meet the low carbon fuel standards, including but not limited to biofuels, biogas, compressed natural gas, gasoline, diesel, hydrogen and electricity;</td>
<td>VI. 1. Covered Fuels</td>
<td>Page 53</td>
</tr>
<tr>
<td>Section 6 (2)(b)(D)</td>
<td>Standards for the issuance of deferrals, established with adequate lead time, as necessary to ensure adequate fuel supplies</td>
<td>VI. 9. Fuel Supply Deferrals</td>
<td>Page 93</td>
</tr>
<tr>
<td>Section 6 (2)(b)(E)</td>
<td>Exemptions for liquefied petroleum gas and other alternative fuels that are used in volumes below thresholds established by the Environmental Quality Commission;</td>
<td>VI. 3. Exemptions</td>
<td>Page 66</td>
</tr>
<tr>
<td>Section 6 (2)(b)(F)</td>
<td>Standards, specifications, testing requirements and other measures as needed to ensure the quality of fuels produced in accordance with the low carbon fuel standards, including but not limited to the requirements of ORS 646.910 to 646.923 and administrative rules adopted by the State Department of Agriculture for motor fuel quality</td>
<td>VI. 11. E. Standards, Specifications, Testing Requirements to Ensure Quality of Fuels</td>
<td>Page 113</td>
</tr>
<tr>
<td>House Bill 2186 reference</td>
<td>Program element required by statute</td>
<td>Relevant Report Section</td>
<td>Page Number</td>
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<tr>
<td>Section 6 (2)(b)(G)</td>
<td>Adjustments to the amounts of greenhouse gas emissions per unit of fuel energy assigned to fuels for combustion and drive train efficiency</td>
<td>VII. 3. Energy Economy Ratios (EERs) and Drive Train Efficiencies</td>
<td>Page 139</td>
</tr>
<tr>
<td>Section 6 (2)(c)</td>
<td>Before adopting standards under this section, the Environmental Quality Commission shall consider the low carbon fuel standards of other states, including but not limited to Washington, for the purpose of determining schedules and goals for the reduction of the average amount of greenhouse gas emissions per unit of fuel energy and the default values for these reductions for applicable fuels</td>
<td>IV. 3. Low Carbon Fuel Standards in Other Areas and Other Related Programs</td>
<td>Page 44</td>
</tr>
<tr>
<td>Section 6 (2)(d)</td>
<td>The Environmental Quality Commission shall provide exemptions and deferrals as necessary to mitigate the costs of complying with the low carbon fuel standards upon a finding by the Environmental Quality Commission that the 12-month rolling weighted average price of gasoline or diesel in Oregon is not competitive with the 12-month rolling weighted average price in the PADD 5 region</td>
<td>VI. 10. Consumer Cost Safety Net</td>
<td>Page 101</td>
</tr>
<tr>
<td>Section 6 (3)(a)</td>
<td>Safety</td>
<td>VI. 11. F. Safety</td>
<td>Page 113</td>
</tr>
<tr>
<td>Section 6 (3)(a)</td>
<td>Feasibility</td>
<td>VIII. Compliance Scenarios and Economic Analysis</td>
<td>Page 145</td>
</tr>
<tr>
<td>Section 6 (3)(b)</td>
<td>Potential adverse impacts to public health and the environment, including but not limited to air quality, water quality and the generation and disposal of waste in this state</td>
<td>IX. Potential Impacts to Public Health and the Environment</td>
<td>Page 155</td>
</tr>
<tr>
<td>House Bill 2186 reference</td>
<td>Program element required by statute</td>
<td>Relevant Report Section</td>
<td>Page Number</td>
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<tr>
<td>Section 6 (3)(c)</td>
<td>Flexible implementation approaches to minimize compliance costs</td>
<td>VI. 13. Flexible Implementation Approaches to Minimize Compliance Cost</td>
<td>Page 119</td>
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<tr>
<td>Section 6 (3)(d)</td>
<td>Technical and economic studies of comparable greenhouse gas emissions reduction measures implemented in other states and any other studies as determined by the Environmental Quality Commission</td>
<td>Appendix D: Economic Analysis Appendix E: Comparable Economic Studies in Other States</td>
<td>Appendix D Appendix E</td>
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<td>Section 6 (4)</td>
<td>The provisions of this section do not apply to: (a) Motor vehicles registered as farm vehicles under the provisions of ORS 805.300. (b) Farm tractors, as defined in ORS 801.265. (c) Implements of husbandry, as defined in ORS 801.310. (d) Motor trucks, as defined in ORS 801.355, used primarily to transport logs</td>
<td>VI. 3. Exemptions</td>
<td>Page 66</td>
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</table>
IV. Background

1. **Overview of the Oregon Low Carbon Fuel Standards**

The 2009 Oregon Legislature authorized Oregon low carbon fuel standards. The proposed rules regulate fuel producers and importers. These are known in Oregon’s low carbon fuel standards program as regulated and opt-in parties. Fuel users, such as the public, construction companies, railroads, and trucking companies, etc. are not regulated under this rule (as required by House Bill 2186).

The proposed rules for Oregon’s low carbon fuel standards require regulated and opt-in parties to reduce the average carbon intensity of gasoline and diesel fuel 10 percent over a 10-year period. It does not limit the amount of fuel sold or imported. DEQ uses the period from 2012-2022 to calculate the required carbon intensity reductions.

The low carbon fuel standards establish average carbon intensity values for various fuels such as gasoline, diesel, biofuels, natural gas, and electricity. Carbon intensity values are calculated using a life-cycle analysis. This accounts for all greenhouse gas emissions associated with a fuel’s production, distribution, and use—as opposed to a simple measure of carbon emissions when a fuel is burned.

Fuel combustion causes greenhouse gases which in turn cause the temperature of the atmosphere to rise—global warming. The amount of greenhouse gases created by combustion varies depending on the fuel being combusted. Therefore, the degree of global warming caused by the greenhouse gases is best expressed as the carbon dioxide equivalent per unit of fuel energy, or CO2e/Megajoule. This standard of measurement allows a comparison between liquid fuels with different energy content per gallon (for example, gasoline vs. ethanol) as well as a comparison liquid and alternative fuels that are delivered in different forms (for example, gasoline vs. compressed natural gas vs. electricity).

The overarching principles in the development of the low carbon fuel standards are to provide flexibility for compliance and to keep the program market-based. Regulated parties have several options to reduce carbon intensity. They can reduce the average carbon intensity of the mix of fuels they supply by increasing their use of low carbon ethanol, low carbon biodiesel, or low carbon renewable diesel, or by acquiring credits from providers of low carbon fuel alternatives including electricity and compressed natural gas. The rules also allow fuel providers of biofuels, biogas, hydrogen, or liquefied natural gas to establish custom carbon intensity values for their fuels if they can demonstrate that the carbon intensity of their feedstock, production process, and transportation system is significantly lower than the industry average.

**Deferrals, Exemptions and Adjustments**

Oregon rules protect businesses and consumers by providing deferrals if there is an inadequate supply of low carbon fuels or if the price of gasoline or diesel in Oregon becomes non-competitive with other states.

The rules also exempt fuel used in farm tractors, registered farm vehicles, implements of husbandry, and log trucks from the rule (as required by House Bill 2186). The rules also exempt fuels used in engines that have special performance needs like aircraft, racing vehicles, military tactical vehicles, oceangoing vessels, and interstate locomotives.
Indirect land use change occurs when greenhouse gases are released when crops are grown to produce biofuels and indirectly lead to changes like deforestation that bring new land into cultivation or more intensive cultivation on existing agricultural land. At this time, Oregon’s rules do not adjust the carbon intensity values of biofuels to compensate for the greenhouse gases generated by indirect land use changes because the science of quantifying indirect land use change is still in development. DEQ intends to adjust the carbon intensity in the future to account for indirect land use change. Other indirect effects like the cost of protecting our foreign oil supply will also be considered for adjustment at a later date as the science develops. Indirect effects, including indirect land use issues are discussed beginning on page 135.

The rules also make adjustments for drive train efficiencies of alternative vehicles through the use of Energy Economy Ratios (EER). This adjustment allows the rules to reflect the differences between drive train technologies including the four-fold greater efficiency that electric motors have compared to internal combustion engines, and the current decreased efficiency of heavy-duty natural gas vehicles compared to diesel fuel use.

The new regulations are fuel-neutral in that all fuels are rated according to their effect on greenhouse gas emissions. Oregon’s low carbon fuel standards do not mandate any particular fuel. Regulated parties are simply required to reduce the overall average carbon content of the mix of fuels they sell by ten percent over ten years. There are many ways in which a regulated party can choose to accomplish this.

**Implementation**

The low carbon fuel standards phase in over time, with small carbon intensity reductions required in the early years of the program, and larger reductions required towards the end of the program. The compliance schedule is back-loaded to allow more time for the development of lower carbon intensity fuels, and for the development and more widespread use of alternatively fueled vehicles and infrastructure.

Oregon’s low carbon fuel standards will be reviewed regularly. Some program elements will be reviewed on an as-needed basis, some annually, some in 2014, and some in 2016 as part of a comprehensive program review. These reviews will keep the program current and allow adjustments for evolving science and technology, implementation needs, and developments in other related programs or a federal low carbon fuel standard.

### 2. Oregon’s Fuels

**Petroleum Production and Transport**

The majority of the petroleum (gasoline and diesel) used in Oregon is imported from four refineries in Washington (90 percent) and one in Utah (10 percent). A small volume of petroleum comes from other sources, and was not included in this analysis. Historically, much of the crude supplying these refineries came from the Alaskan North Slope transferred south by the Trans Alaskan Pipeline and then by tankers to west coast refineries. Today, approximately 65 percent of the petroleum delivered to Oregon from Washington refineries is transported along the Olympic Pipeline, and roughly 35 percent is transported by ocean tanker.
The refineries supplying Oregon also use Canadian crude, a portion of which comes from tar sands and is considered high carbon intensity crude due to the extraction techniques used. Product delivered from Washington contains approximately 8 percent by volume petroleum extracted from oil sands. Product from Utah contains roughly 12 percent. Canadian crude is transported directly to the four Washington refineries via the Trans Mountain Pipeline. A smaller portion of petroleum product is trucked into Southern Oregon from pipeline terminals in Nevada that originate from the Bay Area in California. Product is also delivered into Eastern Oregon from pipeline terminals in Idaho that transport petroleum from a refinery in Utah. Figure 1 on page 42 illustrates how petroleum products are imported into Oregon.

Figure 1: Oregon’s Petroleum Imports

[Map showing petroleum imports into Oregon, with legend indicating refineries, product terminals, and pipeline routes.]

Source: ICF International
Petroleum Consumption

Over 1.58 billion gallons of gasoline were consumed in Oregon in 2007. In 2007, approximately 773 million gallons of distillate (includes diesel) were used in Oregon, and of that total, over 580 million gallons were used in on-highway and off-highway vehicle transportation. (Oregon DEQ website 2009, "Motor Fuel & Distillate In Oregon Quantity, Sources & Distribution", 1) The table below shows 2007 diesel volumes in Oregon for all uses, however, not all will be covered by the Oregon’s low carbon fuel standards. For more information on which fuels the low carbon fuel standards apply to, please see the section on “Covered Fuels” on page 53 of this report.

Table 3: Oregon Distillate Consumption

<table>
<thead>
<tr>
<th>Oregon Distillate Consumption (773 Million Gallons Distillate Total 2007 (EIA))</th>
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<tr>
<td>Residential</td>
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<td>Commercial</td>
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<td>Military</td>
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<td>Off-Highway</td>
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Table from Nov. 3, 2009 Low Carbon Fuel Standards Presentation: Motor Fuel & Distillate In Oregon Quantity, Sources & Distribution. Rick Wallace Oregon Department of Energy

Blending Oregon’s renewable fuels standard (see page 45) requires 10 percent ethanol in all regular and mid-grade use gasoline. Retailers have the option of offering premium gasoline that has no ethanol blended in. It is estimated that 151 million gallons of ethanol are blended with gasoline each year in Oregon. Sales of higher blends of ethanol (E85) are not currently tracked, but those gallons are included in the 2008 gasoline volume estimates from the Oregon Department of Transportation. Oregon’s renewable fuels standard also requires a 2 percent biodiesel blend in all diesel products sold, except fuel used in locomotives and marine applications. Use of blended biodiesel is estimated at 11.7 million gallons per year. Sales of higher blends of biodiesel are not currently tracked, but those gallons are included into the 2007 distillate numbers in Table 3 above.

Alternative Fuels

Currently, there are five known vehicle fleets in Oregon fueled by compressed natural gas, two fleets using liquefied petroleum gas (propane), and none that use liquefied natural gas or hydrogen. There are over 400 electric vehicles currently registered with ODOT’s Driver’s and Motor Vehicles
Division. (Oregon DEQ website 2009, "Motor Fuel & Distillate in Oregon Quantity, Sources & Distribution") There are 400 registered highway CNG vehicles in Oregon. According to the Energy Information Administration, in 2007 there were 1,500 CNG vehicles and equipment in Oregon. (U.S. DOE EIA website 2010, "Alternatives to Traditional Transportation Fuels")

Currently in Oregon there are three facilities producing starch and sugar-based ethanol and seven facilities producing Biodiesel (FAME) at a commercial scale. Renewable diesel, Fischer-Tropsch and other synthetic fuels, butanol and biofuels from algae are not being commercially produced in Oregon at present.

3. **Low Carbon Fuel Standards in Other Areas and Other Related Programs**

A. Low Carbon Fuel Standards

**California**

In 2009, California became the first state in the nation to adopt a low carbon fuel standard. Its goal is to achieve a 10 percent carbon intensity reduction in transportation fuels by 2020. Low carbon fuel standards regulation was approved by the Air Resources Board on April 23, 2009 and became law on January 12, 2010. An ensuing resolution directed the Air Resources Board to establish several workgroups to address the issues raised by stakeholders during the rulemaking process. They include: the expert workgroup (indirect land use change and other indirect effects), the high carbon crude oil workgroup, the sustainability workgroup, the lifecycle analysis workgroup, the policy and regulatory workgroup, the environmental and economic workgroup, and the reporting tool workgroup. These workgroups are currently meeting and their findings will be presented to the Air Resources Board as part of the comprehensive program review due by January 1, 2012.

For California, 2010 was a “reporting only” year, and compliance is scheduled to begin in 2011. For more information on California’s low carbon fuel standard program, please visit [www.arb.ca.gov/fuels/lcfs/lcfs.htm](http://www.arb.ca.gov/fuels/lcfs/lcfs.htm).

**Northeast and Mid-Atlantic States**

Northeast and Mid-Atlantic States are developing low carbon fuel standards for transportation fuels to be applied throughout the region. Participating states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island and Vermont. Participants have signed a Memorandum of Understanding in which they commit to finalize a proposed low carbon fuel standards program framework in 2011.

Information on the Northeast and Mid-Atlantic States’ development of a low carbon fuel standard is available at: [www.nescaum.org/topics/low-carbon-fuels](http://www.nescaum.org/topics/low-carbon-fuels)
Washington State

Under Executive Order 09-05, the Washington Department of Ecology is assessing what low carbon fuel standard provisions, including low carbon fuel standards currently under consideration in other states, would best help Washington State meet its greenhouse gas emissions reduction goals. To that end, Washington conducted a series of public workshops from October, 2009 through September 2010 to discuss low carbon fuel issues with knowledgeable or potentially regulated parties. The Department of Ecology will submit final recommendations and a report to the Governor on whether to pursue adoption of a Washington low carbon fuel standard, what low carbon fuel standard provisions would best fit, and how to implement a program if recommended. Additional information is available at: www.ecy.wa.gov/climatechange/fuelstandards.htm.

British Columbia

In 2008, the province of British Columbia adopted the Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act, which requires a 10 percent reduction in carbon intensity from 2010 to 2020. For more information, please visit www.empr.gov.bc.ca/RET/RLCFRR/Pages/default.aspx.

European Union

European nations adopted changes to Fuel Quality Directive 98/70/EC in December 2008. The non-binding modifications aim to reduce the life-cycle greenhouse gas emissions per unit of fuel energy of transportation fuels by 10 percent from 2011 to 2020. At least six percent of the reduction should come from wider use of biofuels and alternative fuels, along with reductions in venting and flaring during petroleum production. An additional 2 percent reduction may be achieved through Carbon Capture and Sequestration, while a further 2 percent may come from offset purchases under the Clean Development Mechanism. The European Union is studying the potential effects of indirect land use changes and will report their findings to the European Parliament.

Western and Midwest States

States participating in the Western Climate Initiative and the Midwestern Greenhouse Gas Accord are considering low carbon fuel standards regulations as a complement to their proposed cap and trade programs, and have initiated conversations to explore the possible benefits from both intra-regional and multi-regional cooperation (along with the Northeastern and Mid-Atlantic states, mentioned above). For more information, please visit www.midwesterngovernors.org/LCFS.htm.

B. Other Related Programs

US Renewable Fuel Standard 2 (RFS2)

While not a low carbon fuel standard, the US EPA has proposed modifications to their existing renewable fuels program that would add greenhouse gas considerations to the regulation’s requirements. The rule changes are mandated by the Energy Independence and Security Act of 2007 and would require fuel providers to increase the use of renewable fuels from 9 billion gallons in
2008 to 36 billion gallons in 2022. Of the 36 billion gallon total, 21 billion must be advanced biofuels that have life-cycle greenhouse gas emissions that are less than half the greenhouse gas emissions of gasoline or diesel fuel. 16 billion gallons of the 21 billion gallons of advanced fuels must be cellulosic (ethanol or diesel derived from cellulosic sources). The 16 billion gallons of cellulosic fuel must meet a 60 percent greenhouse gas reduction requirement. The proposal would also make adjustments to the carbon intensity of renewable fuels for the increased greenhouse gas emissions caused by indirect land use changes.

This regulation differs from low carbon fuel standards regulations because it applies only to fuels from renewable sources. It does not affect or stimulate the development of other promising new alternatives including electricity, compressed natural gas, liquid natural gas or hydrogen. It also does not specify where these fuels are to be used. Information on EPA’s Renewable Fuel Standard is available at: http://epa.gov/otaq/fuels/renewablefuels/index.htm.

Oregon Renewable Fuel Standard

In 2007, the Oregon Legislative Assembly passed Oregon’s renewable fuel standard mandate for blending biodiesel and ethanol with Oregon’s motor fuels. (Oregon Department of Agriculture website, "Biofuel Renewable Fuel Standard", 4) The mandate requires that diesel sold statewide contain a minimum of 2 percent biodiesel by volume as of October 1, 2009. Exceptions to the blend requirement were made for fuels sold for use by railroad locomotives, marine engines, and home heating applications. When the biodiesel production capacity in Oregon reaches 15 million gallons per year, the percent blend of biodiesel required will increase to 5 percent.

The Oregon renewable fuel standard also requires that gasoline sold statewide contain 10 percent ethanol. Exceptions to this include premium unleaded gasoline of 91 octane or higher, aircraft, antique vehicles, all-terrain vehicles, racing activity vehicles, snowmobiles, tools including but not limited to lawn mowers, leaf blowers, and chain saws, or watercraft. Locations are not required to offer a non-ethanol blended fuel, but they have the ability to make a business decision to provide it based upon customer demand. The Oregon State Marine Board has a list of locations on their website offering non-ethanol blended gasoline. Information on Oregon’s renewable fuel standard is available at: www.oregon.gov/ODA/MSD/renewable_fuel_standard.shtml.

Portland Renewable Fuel Standard

In July 2006, the City of Portland adopted a renewable fuel standard for all motor vehicle fuels sold inside the city limits. The standard requires that all diesel fuel sold in the city contain a minimum of 5 percent biodiesel. The standard generally applies to retail vendors selling diesel to the public within the city limits, card lock operations and to fleet operators who purchase fuels wholesale. A requirement that all diesel sold in the City of Portland contain at least 10 percent biodiesel by volume by July 1, 2010 was temporarily suspended due to economic and technical circumstances. The 5 percent blending requirement still exists for all diesel fuel sold within city limits. Information on Portland’s renewable fuel standard is available at: www.portlandonline.com/bds/index.cfm?c=43886.
V. Oregon Low Carbon Fuel Standards Development Process

1. Advisory Committee Process

A. Introduction
The 2009 Legislature authorized the Environmental Quality Commission to adopt low carbon fuel standards in order to reduce greenhouse gas emissions from gasoline, diesel, or any fuel that substitutes for gasoline or diesel.

In order to get input on the structure of the low carbon fuel standards program, and on a variety of policy issues with setting low carbon fuel standards, DEQ formed a 29-member advisory committee representing petroleum fuel producers, alternative fuel producers, environmental interests, businesses, citizens, local government, labor unions, and fuel users such as truckers, the driving public (represented by AAA), railroads, construction industry, the farming industry, and marine users. The low carbon fuel advisory committee, chaired by Mark Reeve, is an extremely diverse group. For a list of advisory committee members, please refer to the list of advisory committee members on page 165.

B. Rulemaking process
Based on comments and recommendations from the advisory committee, DEQ staff will develop draft rules for Oregon’s low carbon fuel standards, which will eventually be proposed to the Environmental Quality Commission for adoption. DEQ uses a formal rule adoption process governed by state administrative law. Input from an advisory committee was a key first part of the rulemaking process, and discussions at the advisory committee have informed DEQ’s development of the low carbon fuel standards program design, and will continue with a draft rule. After the advisory committee process is completed, DEQ will continue the rulemaking with a formal public comment period. DEQ considers all public comments, and if warranted, alters the draft rule based on those comments. Finally, DEQ will propose a rule to the Environmental Quality Commission for adoption.

C. Advisory Committee Process
DEQ has vetted policy issues and program details with the advisory committee in order to ensure that a wide variety of stakeholder perspectives have formed DEQ’s initial low carbon fuel standards program design. DEQ has conducted an open and transparent process with diverse stakeholder input. The Low Carbon Fuel Advisory Committee was formed in November 2009 and met regularly through December 2010. The committee was asked to discuss and give input on key program policy and technical issues influencing the design and implementation of low carbon fuel standards in Oregon. Discussions at the advisory committee meetings were productive and involved, and DEQ received input that has improved the proposed low carbon fuel standards substantially. The committee’s discussions were used by DEQ in forming its draft low carbon fuel standards rules, which will later be proposed for broader public review and comments as part of DEQ’s rulemaking process. Recognizing the complexity of a low carbon fuel standards program, DEQ did not seek consensus positions from the committee, nor was the committee asked to vote on specific issues. However, DEQ gave great weight to any committee recommendation for which there was
A summary of advisory committee comments in Appendix A: Advisory Committee Input documents the different perspectives and recommendations of committee members.

**Briefing Materials:** Generally, DEQ staff emailed briefing materials such as a discussion paper or presentation at least one week prior to each meeting. At meetings, DEQ presented the issues described in the discussion paper or presentation, addressing each policy issue to solicit discussion among the group and recommendations from individual advisory committee members. Often, there were several options to discuss, and DEQ outlined considerations, pros, and cons of the options. Sometimes advisory committee members came up with new options, or altered the DEQ proposal substantially.

For complicated technical analyses, such as the lifecycle analysis or economic analysis, DEQ presented a proposal outlining the scope and methodology of the work to be done, solicited input from the advisory committee, and then completed the work and returned to the committee for input on resulting policy decisions.

**Public Comment:** All advisory committee meetings were open to the public and had a limited time set-aside for the public to speak. All public comments made at the advisory committee meetings are included in Appendix A: Advisory Committee Input. Additionally, citizens who wished to submit comments were encouraged to communicate directly with a Low Carbon Fuel Advisory Committee member or to communicate by submitting written comments to the DEQ staff.

**Meeting Notes:** DEQ staff prepared Low Carbon Fuel Advisory Committee meeting notes. Meeting notes summarized advisory committee comments and questions raised during the discussion, whether and how issues were resolved, and committee member recommendations regarding program elements, implementation, and other action items. The meeting summaries were posted on the Project website at: www.deq.state.or.us/committees/advcomLowCarbonFuel.htm. Summarized comments on policy issues are also included in Appendix A: Advisory Committee Input.

**Advisory Committee Comments:** DEQ often allowed for time after a meeting for the advisory committee to comment on a policy issue. DEQ carefully considered each comment made at an advisory committee meeting or submitted in writing after the meeting. All comments received were compiled, summarized, considered, and included as Appendix A: Advisory Committee Input.

**Advisory Committee Process and Program Design Report:** This final report documents DEQ’s proposed program design and the different perspectives and recommendations of advisory committee members. Where the advisory committee achieved consensus on any issue, the meeting summaries reflect that. This report, after review by the advisory committee, will be submitted to the DEQ Director.

Through this open and transparent advisory committee process, citizens and groups potentially affected by the rule have had ample opportunity for input to date, and will continue to have opportunity for input as DEQ moves forward with the rulemaking process. It was extremely
important that advisory committee members representing stakeholder groups communicate with their respective groups.

In the future, DEQ will continue the formal and public rulemaking process to seek public and stakeholder review and comment on the proposed draft rules. DEQ’s low carbon fuel standards draft rule may be modified based on public comment.

**D. Policy Issues for the Advisory Committee to Address**

Some of the provisions in the authorizing statute (House Bill 2186) are specific, and allow little or no room for interpretation. Others provisions set up general guidelines, but leave certain details and policy decisions to the Environmental Quality Commission. DEQ identified policy issues, which needed to be resolved during the development of the low carbon fuel standards program. The low carbon fuel advisory committee revised these issues and added some policy issues, resulting in the following 19 policy issues, which were addressed in detail by the advisory committee.

These are described in more detail in Agenda Item C for the November 3rd advisory committee meeting entitled “Rulemaking Process and Policy Issues.”

http://www.deq.state.or.us/aq/committees/docs/november09/revisedPolicyIssue.pdf

Where an issue has a specific requirement or mention in House Bill 2186, the section is noted.

- Effect of sunset (Section 9 (2)(d))
- Consumer cost safety net (exemptions and deferrals to mitigate a non-competitive price of gasoline or diesel) (Section 6, (2)(d))
- Fuels covered under the low carbon fuel standards (including which ones are opt-in) (Section 6 (2)(b)(C))
- Exemption thresholds and exempted fuels (Section 6, (2)(b)(E), and Section 6, (4)(a)-(d))
- Oregon’s approach to lifecycle analysis and calculating fuel carbon intensities (Section 6, (2)(b)(B)), including drive train efficiencies, (Section 6 (2)(b)(G))
- Economic analysis (Section 6 (3)(a) and Section 6 (3)(d))
- Regulated and Opt-in parties
- Credits and deficits
- Compliance scenarios and feasibility (Section 6 (3)(a))
- Electricity-specific issues
- Short term and forecasted fuel supply deferrals (Section 6, (2)(b)(D))
- Indirect land use change (Sec. 6 (2)(b)(B))
- Process for establishing new fuel pathways (adding or updating a carbon intensity)
- Implementation issues (Section 6 (3)(c))
- Phase-in schedule (Section 6 (2)(b)(A) and 6 (2)(c))
- Public health and environmental impacts (Section 6 (3)(a) and (b))
E. DEQ Contractors

DEQ hired two contractors to assist with various aspects of the low carbon fuel standards program development.

TIAX is a pioneering technology development company that combines a deep understanding of markets and applications, and strong links to innovation sources. TIAX has over three decades of experience assisting clients with their energy and environmental needs. TIAX has worked extensively with state and regional agencies to analyze the impacts of transportation policy, and has significant experience in lifecycle analysis of fuels. TIAX performed quality assurance on DEQ’s lifecycle analysis work, developed compliance scenarios (see Appendix F: Compliance Scenario Documentation), estimated the costs of infrastructure needed to support low carbon fuel standards (see Appendix C: Infrastructure Cost Assumptions Memorandum), and evaluated indirect land use change methodologies (see Appendix G: Indirect Land Use Change Comparative Analysis).

Jack Faucett Associates (JFA) is a pioneer in the field of economic research and public policy analysis. JFA conducted the economic impact analysis of the low carbon fuel standards program (see Appendix D: Economic Analysis), as well as analyzing comparable economic studies in other states (see Appendix E: Comparable Studies in Other States Memorandum). JFA brings a wealth of information on transportation, energy, the environment, economic development, and public sector management issues, and is a leading transportation energy research firm with over forty years of experience supporting agencies at all level of government in the development of transportation energy policies and programs.

2. Oregon Interagency Collaboration Process

Oregon’s Low Carbon Fuel Standards Interagency Team consists of Oregon DEQ, Oregon Department of Agriculture, Oregon Department of Energy, Oregon Business, Oregon Department of Transportation, and Oregon Public Utility Commission. The team met initially to inform agencies about the low carbon fuel standards development process, figure out which policy issues each agency was interested in, identify areas for collaboration, identify data sources and areas of expertise, and identify which of the 19 low carbon fuel standards policy issues each agency was interested in.

The interagency team met periodically to discuss upcoming issues for advisory committee discussion, and collaborate where needed. Each agency has different jurisdiction and areas of expertise.

- 9/21/2009 Interagency meeting
- 10/20/2009 Interagency meeting
- 3/16/2010 Interagency meeting
- 4/1/2010 Biomass study review and conference call with Oregon Department of Agriculture, Oregon Department of Energy, and Oregon Department of Forestry
- 6/2/2010 Interagency meeting

In addition to the interagency team meetings, DEQ consulted or collaborated with relevant agencies on the fuels assessment, current production and use of conventional and alternative
fuels, regulated and opt-in parties (particularly consultation with ODOT fuels tax group on regulated parties for gasoline, diesel, and biofuels), compliance scenario development, economic impact analysis, biomass availability, biofuels feedstock availability, indirect land use change, the carbon intensity of electricity, exemptions for farm vehicles, lifecycle analysis, fuel specifications, effect of the sunset, and each policy issue that an agency indicated they would like to discuss with DEQ.

3. **Stakeholder meetings**

DEQ also met with stakeholder groups either upon request, or in seeking information to inform the advisory committee discussion of a policy issue. DEQ held the following meetings:

- Western States Petroleum Industry on 9/1/2009
- BP on 9/30/2009
- ForestEthics on 10/7/2009 (phone call)
- Consumer-owned utilities on 11/30/2009
- Tesoro on 12/14/2009
- Attended meeting on regulated parties for Greenhouse Gas Reporting rule on 1/6/2010
- Railroad Meeting on 1/22/2010
- Global Warming Commission (Angus Duncan) on 2/11/2010
- ZeaChem (Carrie Atiyeh) on 2/23/2010
- Railroad Meeting on 2/23/2010 (phone call)
- Farm Bureau (to update new staff on low carbon fuel standards) on 3/9/2010
- Railroad Meeting on 3/22/2010
- Electric utilities on 3/30/2010
- Electric utilities on 4/28/2010
- Electric utilities on 5/6/2010
- Railroad Meeting on 5/6/2010
- Farm Bureau on 6/7/2010
- Field trip to Chevron on 6/8/2010
- Meeting on potential regulated parties for petroleum and biofuels on 6/14/2010
- Good Company on GREET on 7/27/2010
- Associated General Contractors (to update new staff on low carbon fuel standards) on 8/3/2010
- SeQuential on 9/1/2010

4. **Coordination with Other Low Carbon Fuel Standards Work**

A. **Washington State**

Under Executive Order 09-05, the Washington Department of Ecology is assessing what low carbon fuel standards provisions, including low carbon fuel standards currently under consideration in other states, would best help Washington State meet its greenhouse gas emissions reduction goals. To that end, Washington conducted a series of public workshops from October 2009 through September 2010 to discuss low carbon fuel issues with knowledgeable or
potentially regulated parties. The Department of Ecology will submit final recommendations and a report to the Governor on whether to pursue adoption of a Washington low carbon fuel standard, what low carbon fuel standard provisions would best fit, and how to implement a program if recommended. Additional information is available at: www.ecy.wa.gov/climatechange/fuelstandards.htm.

Washington Department of Ecology low carbon fuel staff presented at the February 2010 Oregon advisory committee meeting to inform the Oregon low carbon fuel advisory committee about Washington’s progress and process.

DEQ has been coordinating with Washington Dept. of Ecology staff working on investigating low carbon fuel standards for Washington. Because 90 percent of Oregon’s petroleum fuels come from Washington, Oregon has been able to collaborate efficiently and effectively with Washington through sharing technical information (such as data and lifecycle analysis work) and contractor work products. DEQ staff attended all relevant Washington State Low Carbon Fuel Standard meetings. In addition, ODEQ has routine check-in calls with Washington State low carbon fuel standards staff.

B. California
The California low carbon fuel standards regulation was approved by the Air Resources Board on April 23, 2009 and became law on January 12, 2010. An ensuing resolution directed the Air Resources Board to establish several workgroups to address the issues raised by the stakeholders during the rulemaking process. They include: the expert workgroup (indirect land use change and other indirect effects), the high carbon crude oil workgroup, the sustainability workgroup, the lifecycle analysis workgroup, the policy and regulatory workgroup, the environmental and economic workgroup, and the reporting tool workgroup. These workgroups are currently meeting and their findings will be presented to the Air Resources Board as part of the comprehensive program review due by January 1, 2012. DEQ staff participated in the expert workgroup and the high carbon crude oil workgroup meetings.

C. Northeast and Mid-Atlantic States
The Northeast and Mid-Atlantic States (Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, Pennsylvania, Delaware, and Maryland) are developing low carbon fuel standards for fuels to be applied throughout the 11-state region. DEQ has participated in meetings focusing on their economic analysis.

D. British Columbia
In 2008, the province of British Columbia adopted the Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act, which requires a 10 percent reduction in carbon intensity from 2010 to 2020. DEQ has coordinated with British Columbia low carbon fuel standards staff on policy issues.
VI. Low Carbon Fuel Standards Program Design

1. Covered Fuels

The main policy question is which fuels should be covered under Oregon’s low carbon fuel standard, and which fuels should be excluded? The first consideration is the quantity of fuel used. Is the fuel used in large quantities? The second consideration is the carbon intensity of the fuel and whether it is higher or lower than the low carbon fuel standard in 2022.

Some low carbon fuels are not currently used in large quantities, and might not be used in large quantities until later in the program. DEQ staff proposes an option for providers of these types of fuels to opt-in to the program at a later date, while higher carbon fuels and fuels supplied in large quantities are regulated (compulsory participants) in the low carbon fuel standard. Opt-in fuels would have no compliance or reporting obligations unless they decided to opt-in.

House Bill 2186

SECTION 6:

(2) (a) The Environmental Quality Commission may adopt by rule low carbon fuel standards for gasoline, diesel and fuels used as substitutes for gasoline or diesel.

(2) (b) The commission may adopt the following related to the standards, including but not limited to:

…(C) Provisions allowing the use of all types of low carbon fuels to meet the low carbon fuel standards, including but not limited to biofuels, biogas, compressed natural gas, gasoline, diesel, hydrogen and electricity;

…(E) Exemptions for liquefied petroleum gas and other alternative fuels that are used in volumes below thresholds established by the commission;

DEQ staff propose the following fuels be covered under Oregon’s Low Carbon Fuel Standard:

- **Gasoline** (derived from fossil sources, such as oil fields or oil sands)
- **Diesel** (derived from fossil sources, such as oil fields or oil sands)
- **Ethanol** (derived from biomass sources such as crops, sugarcane, wood waste, food waste or agricultural waste)
- **Biomass-based diesel** (a diesel fuel substitute produced from biomass sources such as soybean, canola, or agricultural/food processing waste)
- **Liquefied natural gas (LNG) from fossil sources** (derived from fossil sources such as oil fields and coal beds)
- **Compressed natural gas (CNG) from fossil sources** (derived from fossil sources such as oil fields and coal beds)
- **Compressed natural gas from non-fossil sources** (also called biogas CNG or biomethane; meets requirements for natural gas, and is produced from the breakdown of organic material such as manure, sewage, municipal solid waste, or green waste in the absence of oxygen)
• **Liquefied natural gas from non-fossil sources** (also called biogas LNG; meets requirements for liquefied natural gas, and is produced from the breakdown of organic material such as manure, sewage, municipal solid waste, or green waste in the absence of oxygen)

• **Electricity** (used for transportation purposes)

• **Hydrogen** (used for transportation purposes)

• **Any other fuel used for transportation purposes that is not listed here, and is not specifically excluded or exempt from the low carbon fuel standards.** This is a placeholder for future fuels that might be developed. Should a new transportation fuel be used in Oregon, such as synthetic fuel, it would be covered under the low carbon fuel standards.

DEQ staff propose that the following fuel NOT be covered under Oregon’s low carbon fuel standards:

• **Liquefied petroleum gas** (propane)

The proposed covered fuels are transportation fuels (including off-road fuel) which could be used in Oregon or are used in Oregon, with the exception of propane. House Bill 2186 authorizes the Environmental Quality Commission to exclude propane from the low carbon fuel standards.

**Alternatives considered**

Advisory committee members requested that propane be included as opt-in to the low carbon fuel standard. DEQ did not propose this option because House Bill 2186 specifically authorizes the exemption of propane from the low carbon fuel standards.

**A. Regulated Fuels**

DEQ staff propose that the following fuels be **regulated (compulsory participants) under low carbon fuel standards**: Gasoline, diesel, fossil LNG that is not made from natural gas supplied through a pipeline, ethanol and ethanol blends, biomass-based diesel, biomass-based diesel blends, and any other liquid or non-liquid fuel not otherwise exempt from the regulation or specified as an opt-in fuel.

**B. Opt-in Fuels**

DEQ staff propose that the following fuels be **Opt-In under low carbon fuel standards**: electricity, compressed or liquefied hydrogen, any fuel blend containing hydrogen, fossil CNG, biogas CNG, biogas LNG, and any fossil LNG made from natural gas supplied through a pipeline. They can choose to opt-in to all requirements to generate credits for sale.

The proposed opt-in structure for the low carbon fuel standards provides compliance flexibility and an opportunity to minimize compliance costs. Opt-in fuel providers can make a decision whether or not to opt-in based on their current resources, volume of fuel used, and potential for selling credits. Because the low carbon fuel standards are back-loaded so that the majority of the carbon intensity reductions occur later in the program, this structure makes a lot of sense for low carbon fuels that are not used in large quantities now, but could be in the future. For example, a rural utility where one
homeowner has purchased an electric vehicle would not need to use resources to meet all of the provisions in the low carbon fuel standards, unless they chose to opt-in.

Once an entity has opted-in, they need to meet all low carbon fuel standards reporting obligations until they notify DEQ that they are opting out. Once opted-out, an opt-in party can sell remaining credits, but must notify DEQ upon sale of credits.

Alternatives considered

Alternative 1: Allow biofuels providers with a carbon intensity lower than the 2022 standards to opt-out of the low carbon fuel standards requirements, or make all biofuels opt-in. *Arguments in favor — 1) Some biofuels have very low carbon intensities.*

Alternative 2: Require all fuels listed as “covered fuels” to meet all reporting and compliance obligations of the low carbon fuel standards. Under this alternative, there would only be regulated parties, and no opt-in parties. *Arguments in favor — 1) Credits from all fuel types will be necessary.*

Alternative 3: Allow only fossil CNG supplied from North American sources to opt-in, instead of allowing any fossil CNG to be opt-in. *Arguments in favor — 1) N. American natural gas has a low carbon footprint, but non-N. American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.*

Alternative 4: Regulate all fossil LNG to be regulated, instead of allowing LNG made from natural gas supplied from a pipeline to be opt-in. *Arguments in favor — 1) LNG could have a higher carbon intensity than the low carbon fuel standards in 2022, depending on the technology used.*

Alternative 5: Allow all fossil LNG to be opt-in. *Arguments in favor — 1) The low carbon fuel standards should encourage alternative fuels, and allowing opt-in for all LNG would accomplish this.*

Rationale for DEQ Proposal

Credits from biofuels will be needed for the program; biofuels are currently commercialized and used in large volumes, so there is no need to allow them to opt-out.

Requiring all fuels to meet all provisions of the low carbon fuel standards do not provide compliance flexibility for small volume providers. For example, a rural utility that has one household with an electric vehicle would need to meet all of the provisions in the low carbon fuel standards. If low carbon fuels used currently in small volumes are opt-in, the fuel provider can consider their current resources, volume of fuel used, and potential for selling credits before opting-in. Allowing lower carbon fuels to opt-in is a flexible implementation approach that reduces compliance cost.

If LNG is imported into Oregon, gasified, distributed by pipeline, and then re-liquefied, the finished LNG is mixed with pipeline natural gas, and maintains a lower than 2022 low carbon fuel standards carbon intensity. Alternatively, LNG imported to Oregon and used in liquefied form could be high carbon intensity, depending on the technology used. DEQ’s proposal regulates any fuel that will be high carbon intensity, while allowing lower carbon intensity LNG to opt-in.
Advisory committee input on this issue can be found in Appendix A.

2. Regulated and Opt-in Parties

The previous section on “Covered Fuels” discussed which fuels should be included, and whether the fuels should be regulated or opt-in. But who, exactly, should report and have the compliance burden to meet the low carbon fuel standards? Which entity should be able to opt-in and sell credits?

In a fuel lifecycle, there is a chain of several owners, from the fuel refiner/producer, the fuel distributor(s), the retail seller, to the end user. Figure 2 below is a conceptual illustration of the supply chain of gasoline.

![Figure 2: Supply Chain of Gasoline](image)

Closer to the source of the fuel, there are fewer owners, while the further the fuel progresses down the distribution chain, the more owners there are. For example, 90 percent of Oregon’s gasoline comes from 4 oil refineries in Washington. At the storage and distribution level, there are approximately 155 gasoline fuel dealers licensed in Oregon. Those distributors supply fuel to approximately 2400 retail facilities, who in turn sell fuel to millions of vehicle and equipment owners.

Each type of fuel covered under the low carbon fuel standards is supplied and used differently. Consequently, the proposed regulated or opt-in party varies with fuel type. There are several considerations for choosing regulated or opt-in parties.

- **The regulated party should capture the use of the fuel for transportation.** Some fuels are used mainly for transportation, while others are not. For example, the bulk of gasoline is used as a transportation fuel, so it makes sense to set the point of regulation as close to the source of the fuel as possible. However, other fuels, such as natural gas or electricity, are used mainly for other purposes, and only a small amount is used for transportation. Therefore, it makes sense to require reporting (if a party has chosen to opt-in) only when the natural gas is compressed into CNG and used for transportation, or electricity is dispensed specifically for use as a transportation fuel.
• **DEQ is seeking the most efficient point of regulation for each type of fuel.** Ideally, the point of regulation would involve as few entities as possible who use, distribute, or sell large amounts of the fuel for transportation purposes.

• **Flexible implementation to minimize compliance cost.** Although in general, DEQ is seeking fewer regulated or opt-in entities, another consideration is that, if possible, the regulation should incorporate flexibility to minimize compliance cost as directed by House Bill 2186.

• **Production and use of low carbon fuels and public access to low carbon fuels.** Where appropriate, implementation should provide incentives for production and use of low carbon fuels, and for providing public access to alternative fuels, such as at a fueling station used by a fleet owner that is also open to the public.

In order to increase flexibility to minimize compliance costs, DEQ staff propose that in certain circumstances, the compliance obligation for a volume of fuel sold transfers with the sale of fuel, and that in other circumstances, it does not. When and how the compliance obligation for a volume of fuel sold transfers is specific to each fuel and is described below.

DEQ staff propose the following regulated and opt-in parties for gasoline, diesel, biofuels, CNG, LNG, biogas, hydrogen, and electricity based on the considerations described above.

**A. Gasoline, Diesel, Biomass-based Diesel and Ethanol**

DEQ, the advisory committee, and stakeholders had extensive discussions about who should be the regulated party for gasoline, diesel, and biofuels. At the low carbon fuel advisory committee’s request, DEQ held a sub-group meeting to have a more focused conversation on the topic of regulated parties for gasoline, diesel, and biofuels. DEQ received input from petroleum industry, biofuel industry, environmental and other representatives. At the meeting, participants discussed various ideas and worked through pros, cons, and considerations related to different regulated party options. A diversity of opinions were expressed at the meeting. Stakeholders for the petroleum and biofuels industry believed that the approach of defining the fuel producer or importer as the regulated party would be workable.

**Proposed:** The regulated party would be the producer or Oregon importer of the fuel or blendstock. The point of regulation would be the point at which finished gasoline or diesel is first manufactured or imported into Oregon. “Importer” means the person who owns an imported product when it is received at the import facility in Oregon. Import facility means, with respect to any imported liquid product, the storage tank in which the product was first delivered from outside Oregon into Oregon, including, in the case of liquid product imported by cargo tank and delivered directly to a facility for dispensing the product into motor vehicles, the cargo tank in which the product was imported. DEQ staff propose that there be two types of importers:

• **Oregon Small Importer:** An importer who imports less than or equal to 50,000 gallons of gasoline and diesel to Oregon.
- **Oregon Large Importer**: An importer who imports more than 50,000 gallons of gasoline and diesel to Oregon.

**Potential regulated parties in Oregon**: There are approximately seven biodiesel producers and two ethanol producers in Oregon. It is unknown how many importers of gasoline, diesel, and biofuels there are, however, there are 155 motor fuel dealers licensed with the Oregon Department of Transportation.

**Transfer of compliance obligation**: The above entities are initially designated as regulated parties who are responsible for low carbon fuel standards compliance obligations. In order to maximize flexibility, the compliance obligation could transfer with the sale of fuel in the following ways:

A. When the fuel or blend stock is sold, and the recipient is a producer or Oregon Large Importer (but not an Oregon Small Importer), the seller can choose from the following two options:
   1. Seller can transfer the compliance obligation to the recipient; or
   2. Seller can choose to retain the compliance obligation.

B. When the fuel or blendstock is sold, and the recipient is NOT a producer or is an Oregon Small Importer, the seller must retain the compliance obligation, unless both the seller and the recipient agree that the recipient will take the compliance obligation. For example, if a fuel importer sells to a distributor (that only buys fuel from within Oregon), the distributor can either refuse or accept the compliance obligation for that fuel purchase.

**Alternatives considered**

Alternative 1: Regulated party is entity that pays ODOT fuels tax. *Arguments in favor — 1) Consistency with fuels tax and DEQ greenhouse gas reporting rule. 2) Person who pays ODOT fuels tax knows the fuel will be used in Oregon.*

Alternative 2: No “Oregon Small Importer” designation. This would lump all fuel importers in one category. *Arguments in favor — 1) This designation of a small importer is not needed, since most small importers will not own fuel as it is imported into Oregon.*

**Rationale for DEQ Proposal**

In general, this would put compliance obligations initially on upstream entities (that is, producers and importers that are legally responsible for the quality of gasoline and diesel transportation fuels in Oregon), rather than downstream distributors and fueling stations.

Consistency with ODOT fuels tax and DEQ greenhouse gas reporting rules was an important consideration in choosing regulated parties. DEQ’s research and discussion with stakeholders showed that the regulated party needs to be different than the entities regulated under ODOT fuels tax and DEQ greenhouse gas reporting rules for the following reasons:

**DEQ did not propose ODOT fuels taxpayers as the regulated party** because ODOT fuel taxpayers are downstream distributors and fueling stations rather than the upstream producers.
and importers. ODOT fuels taxpayers will not necessarily know the carbon intensity of the biofuels they purchase, but the importer will. Non-road fuels are not covered under ODOT’s tax program, but are included in the low carbon fuel standards. Lastly, exemptions do not align with ODOT fuels taxpayers.

**DEQ did not propose DEQ greenhouse gas reporters** because their reporting requirements have different emission quantification methodologies and do not consider lifecycle emissions, as the low carbon fuel standards require. In addition, the entities subject to DEQ greenhouse reporting are different than the regulated parties under the low carbon fuel standards.

Allowing the transfer of the compliance obligation with the sale of fuel provides flexibility. For example, if Company A has access to only high carbon fuels, it might have difficulty meeting the low carbon fuel standards. It would want to transfer compliance obligations with all fuel sold. But Company B has access to low carbon fuels and could accept the compliance obligations from Company A and could still meet the low carbon fuel standards by averaging the higher carbon intensity fuels from Company A with its lower carbon fuels. This arrangement could be mutually beneficial to both companies, and would be a market-based decision on their part.

Participants in the subgroup meeting also explored the option of exempting small gas stations. Small gas stations could become a regulated party under the low carbon fuel standards, if they own the fuel or blendstock when it crosses into Oregon, and could then not refuse the compliance obligation for any fuel purchased, including fuel purchased from within Oregon. Some participants felt that DEQ should consider provisions to protect these small businesses. Some participants felt strongly that small gas stations should not be exempt from the low carbon fuel standard because of fairness issues. Others felt that separating out small gas stations was not needed since they do not import their own fuel. Allowing the transfer of the compliance obligation is a way to increase flexibility in the regulation and to decrease compliance costs.

DEQ felt that it was important to delineate between “Small” and “Large” importers because of its importance in how and if the compliance obligations for a volume of fuel can transfer with the sale of that fuel. Although the “Small” and “Large” designation is based on volume, what it really represents is an entity’s ability to comply, for the additional administrative responsibilities, access to low carbon fuels, or cash to purchase credits.

Under DEQ’s proposal, small importers, including gas stations, would have the compliance obligation for fuel they import, but could refuse compliance obligation for fuel bought in Oregon. This flexibility gives small gas stations with limited resources the ability to manage participation in the low carbon fuel standard for all of the fuel they buy. Based on our discussions with the subgroup, it seems the best way for individual gas stations to remain unregulated by the low carbon fuel standards program would be to take legal possession of fuel only when it is delivered to the gas station. They would therefore not be considered an importer of fuel. In this case, the out-of-state provider would be the importer because they own the fuel when it enters Oregon.

### B. Compressed Natural Gas (CNG) from Fossil Sources

**Proposed:** All CNG from fossil sources would be Opt-in. The opt-in party would be the utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon for transportation use.
Potential opt-in parties in Oregon:

- Three natural gas companies (own the majority of Oregon’s 11 fueling stations)
- CNG fleet owners who own fuel dispensing equipment (several CNG fleet owners in OR own the fuel dispensing equipment, for example, Rogue Valley Transit, Port of Portland, and Jackson County)
- A limited number of home fueling units

Transfer of credits: If another entity purchases the fuel, and both parties involved agree, the credits can transfer to the purchaser of the fuel. For example, if Company A owns a CNG fueling station that Company B also uses, Company A is the opt-in party for all fuel sold by that fueling station, including fuel sold to Company B. However, if both Companies A and B agree, the credits for fuel sold to Company B could transfer, and then Company B could opt-in and sell credits for the CNG they used for transportation purposes.

Alternatives considered

Alternative 1: Allow only fossil CNG supplied from North American sources to opt-in, instead of allowing any fossil CNG to be opt-in. Arguments in favor — 1) North American natural gas has a low carbon footprint, but non-North American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.

Alternative 2: Do not allow a natural gas utility to participate in program if infrastructure or fuels are subsidized by ratepayers. Arguments in favor — 1) Using ratepayer funds to subsidize infrastructure or fuel cost creates an anti-competitive environment in which private enterprise would struggle to compete.

Rationale for DEQ Proposal

This choice of an opt-in party captures only the transportation use of natural gas, which represents less than 1 percent of the CNG sold in Oregon. This proposal provides flexibility because the opt-in party could either be a natural gas company who owns the CNG fuel dispensing equipment, or it could be a large fleet owner that decided to put in a fueling station. There is also an incentive for the owner of the fuel dispensing equipment to provide access to CNG fuel and earn credits from sales to other CNG users. It is DEQ’s understanding that natural gas utilities cannot use ratepayer funds to subsidize fuel or infrastructure cost for sales of transportation CNG to the public.

Because any non-North American natural gas would be mixed with North American gas in the pipeline, the effective carbon intensity at the point of use will likely remain lower than the 2022 low carbon fuel standards.
C. Liquefied Natural Gas (LNG) from Fossil Sources

**Proposed:**

**Opt-in:** Any LNG produced from natural gas supplied through a North American pipeline.

**Regulated:** Any LNG that is not derived from natural gas supplied from a natural gas pipeline. This includes LNG that is brought to Oregon in liquefied form and delivered in liquefied form to a fueling facility. See **Figure 3** on page 61.

The regulated or opt-in party would be the utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon for transportation use.

**Potential regulated or opt-in parties in Oregon:** none at this time. LNG is not currently used as a transportation fuel in Oregon.

**Transfer of compliance obligation or credits:** If another entity purchases the fuel, and both parties involved agree, the compliance obligation or credits can transfer to the purchaser of the fuel.

**Figure 3: LNG Pathways, Carbon Intensity, and Opt-in/Regulated Parties**
Alternatives considered

Alternative 1: Do not allow a natural gas utility to participate in program if infrastructure or fuels are subsidized by ratepayers. Arguments in favor — 1) Using ratepayer funds to subsidize infrastructure or fuel cost creates an anti-competitive environment in which private enterprise would struggle to compete.

Rationale for DEQ Proposal

Less than 1 percent of the natural gas sold in Oregon is used in transportation and none of it currently comes into Oregon in liquefied form, As depicted in Figure 3, LNG could follow three different pathways prior to use as a transportation fuel (See Figure 3 on page 61). First, it might enter Oregon in a pipeline and be liquefied and trucked to a fueling station. Second, it could be barged to North America in liquefied form, gasified and injected into a natural gas pipeline for transport across the state, re-liquefied and trucked to a fueling station. Lastly, it could be barged to North America as LNG and be trucked directly to a fueling station. LNG supplied through the first two methods would be mixed with relatively lower carbon intensity natural gas. LNG supplied through the third method might have a higher carbon intensity, depending on the specifics of the process, making it a high carbon fuel rather than a low carbon one. Therefore, LNG not derived from natural gas supplied through a natural gas pipeline is regulated, while all other LNG is opt-in.

This proposal captures only the transportation use of natural gas. It also provides flexibility because the regulated or opt-in party could either be a natural gas company who owns the LNG fuel dispensing equipment, or it could be a large fleet owner that decided to put in a fueling station. In general, DEQ’s proposal regulates any fuel that will be high carbon intensity, while allowing lower carbon intensity fuels to be opt-in.

It is DEQ’s understanding that natural gas utilities cannot use ratepayer funds to subsidize fuel or infrastructure cost for sales of transportation LNG to the public.

D. Biogas (CNG or LNG derived from Biogas)

Proposed: All biogas would be opt-in. The opt-in party would be the producer or Oregon importer of the biogas, if the producer or importer retains custody in the pipeline. If custody of the fuel is transferred to the pipeline, then the pipeline becomes the opt-in party. The opt-in party must show that the fuel has been used for transportation in Oregon.

Potential opt-in parties in Oregon: There are a limited number of entities that currently produce biogas in Oregon (six landfills, nine wastewater treatment plants, and three agricultural operations). If the producer compresses or liquefies and dispenses the fuel for use in their own fleet, the producer can opt-in to earn and sell credits. For biogas that enters a natural gas pipeline (this currently does not occur in Oregon, but it could), the biogas producer could retain custody of the natural gas and earn credits with a demonstration that the fuel has been used transportation in Oregon.

Transfer of credits with sale of fuel: If another entity purchases the fuel, and both parties involved agree, the compliance obligation or credits can transfer to the purchaser of the fuel.
Alternatives considered

Alternative 1: Utility Company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon. Arguments in favor — 1) The entity that owns the fuel dispensing equipment in Oregon will have documentation that the fuel was used for transportation.

Alternative 2: In order to demonstrate that biogas has been used for transportation purposes, a producer or importer could use a “biogas swap” instead of paying for transportation in the pipeline. In a biogas swap, the producer contracts for production and sale of biogas without transfer to that customer. Arguments in favor — 1) This is a common practice in the electricity market and eliminates pipeline transfer fees. Because greenhouse gases are not local pollutants, actually reducing emissions in Oregon is not necessary. 2) Not allowing biogas swaps creates an unfair advantage of electricity over gas.

Rationale for DEQ Proposal

The producer or Oregon importer of the fuel should get the credits. This proposal provides an incentive for production of low carbon fuels, while capturing the transportation use of the fuel. Proper documentation can provide certainty that the biogas was used for transportation. If the producer or importer pays the pipeline operator for the transfer of biogas through the pipeline system, this can demonstrate the physical pathway of the biogas from the producer or importer to the transportation use.

E. Hydrogen

Proposed: All hydrogen would be opt-in. The opt-in party would be the entity who owns the fuel at the time the finished fuel is made or imported into Oregon. “Finished fuel” means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.

Potential opt-in parties in Oregon: None known at this time.

Transfer of credits: If another entity purchases the fuel, and both parties involved agree, the compliance obligation or credits can transfer to the purchaser of the fuel.

Rationale for DEQ Proposal

The finished fuel can either be made prior to fuel dispensing, or can be made in a vehicle. This choice for opt-in parties covers both possibilities.

F. Electricity

Proposed: All electricity would be opt-in. The following opt-in parties are listed in order of their opt-in priority:
1. **Bundled services provider:** Any person or entity that provides bundled charging infrastructure and other electric transportation services and provides vehicle charging under contract with vehicle owners or operators.

2. **Electricity provider:** Any privately owned, publicly owned or cooperatively owned utility or other person that supplies electricity to vehicle charging equipment. This includes owners of solar powered facilities used to generate electricity for vehicle charging.

3. **Owner and operator of electric charging equipment** (including a homeowner with electric vehicle charging equipment).

The electricity opt-in period will be for one year. The opt-in party with the highest priority (above) will maintain opt-in rights for a particular service for the full one-year period.

**Potential opt-in parties in Oregon:** Oregon has 39 electricity providers (36 utilities and three electricity service suppliers). Electric vehicle fleet owners or homeowners who own charging equipment are also potential opt-in parties.

**Transfer of credits:** None.

**Alternatives considered**

Alternative 1: Opt-in is for more than one year. *Arguments in favor — 1) this will help ensure that electric vehicles can take advantage of the low carbon fuel standards as a market driver.*

**Rationale for DEQ Proposal**

Most of the electricity (over 99 percent) sold in Oregon is not used for transportation. This choice of an opt-in party captures only the transportation use of electricity and provides the flexibility of an opt-in process. As with other fuels, DEQ prefers an opt-in party that is larger and higher up in the chain of fuel distribution (closer to the source). In the case of electricity, DEQ provided the option for owners of charging equipment to opt-in to recognize that utilities might not opt-in until the latter part of the program timeline. The one-year opt-in is intended to give electricity suppliers opportunity to opt-in.

Please note that an Oregon Public Utilities Commission Docket is currently addressing electric vehicle charging issues, and this section on regulated parties for electricity might be updated based on changes due to the Docket.

*Advisory committee input on this issue can be found in Appendix A.*

**Table 4: Summary of Regulated and Opt-in Parties**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Regulated or Opt-In?</th>
<th>Regulated Party</th>
<th>Point of regulation</th>
<th>Transfer of compliance obligation or credits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
<td>Regulated or Opt-In?</td>
<td>Regulated Party</td>
<td>Point of regulation</td>
<td>Transfer of compliance obligation or credits</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>----------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Gasoline, Diesel, Biomass-based diesel, and Ethanol</td>
<td>Regulated</td>
<td>Producer, Oregon Large Importer, or Oregon Small Importer of the fuel</td>
<td>Point at which fuel is produced in Oregon or imported into Oregon</td>
<td>The seller decides if the compliance obligation transfers with the sale of the fuel if the fuel is sold to an Oregon Large Importer or producer. If the fuel is sold to an Oregon Small Importer or a person that does not import fuel, the purchaser can refuse the compliance obligation when purchasing fuel.</td>
</tr>
<tr>
<td>Compressed Natural Gas (fossil sources)</td>
<td>Opt-in</td>
<td>Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon</td>
<td>Point at which the fuel is dispensed for transportation use</td>
<td>Transfer only occurs if both transferor and recipient agree.</td>
</tr>
<tr>
<td>Liquefied Natural Gas (fossil sources)</td>
<td>Opt-in: any LNG produced from natural gas supplied through a pipeline Regulated: all other LNG</td>
<td>Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon</td>
<td>Point at which the fuel is dispensed for transportation use</td>
<td>Transfer only occurs if both transferor and recipient agree.</td>
</tr>
<tr>
<td>Biogas CNG, Biogas LNG</td>
<td>Opt-in</td>
<td>Producer or Oregon importer</td>
<td>Point at which the fuel is produced in Oregon or imported into Oregon</td>
<td>Transfer only occurs if both transferor and recipient agree.</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Opt-in</td>
<td>Person who owns the fuel at the time the finished fuel is made or imported into Oregon</td>
<td>Point at which finished fuel is first manufactured or imported into Oregon</td>
<td>Transfer only occurs if both transferor and recipient agree.</td>
</tr>
<tr>
<td>Electricity</td>
<td>Opt-in</td>
<td>Opt-in priority: 1. Bundled services provider 2. Electricity provider, 3. Owner and operator of electric charging equipment (including homeowners).</td>
<td>Point at which electricity is dispensed for transportation use.</td>
<td>None.</td>
</tr>
</tbody>
</table>

*Advisory committee input on this issue can be found in Appendix A.*
3. **Exemptions**

House Bill 2186 allows the Environmental Quality Commission to provide exemptions from the low carbon fuel standards, including but not limited to the following:

**HB 2186 Section 6:**

(2)(a) The Environmental Quality Commission may adopt by rule low carbon fuel standards for gasoline, diesel and fuels used as substitutes for gasoline or diesel.

(2)(b) The commission may adopt the following related to the standards, including but not limited to:

(2)(b)(E) Exemptions for liquefied petroleum gas and other alternative fuels that are used in volumes below thresholds established by the commission;

(4) The provisions of this section do not apply to:

- (4)(a) Motor vehicles registered as farm vehicles under the provisions of ORS 805.300.
- (4)(b) Farm tractors, as defined in ORS 801.265.
- (4)(c) Implements of husbandry, as defined in ORS 801.310.
- (4)(d) Motor trucks, as defined in ORS 801.355, used primarily to transport logs.

The **low carbon fuel standards do not regulate fuel users**; they are directed at producers and Oregon importers of transportation fuels. The low carbon fuel standards do not limit the kinds of fuel a fuel user may possess. This includes, but it not limited to the operator or owner of a farm truck or tractor, implements of husbandry, or log truck as identified in Sub-paragraph (4) above.

The practical consequence of the exemptions in Section 6 is that the carbon intensity of exempt fuels would not count in determining compliance with the declining average carbon intensity requirement of the low carbon fuel standards. Regulated and opt-in parties will need to track all volumes of fuel distributed and differentiate between regulated and exempt fuel for reporting purposes.

The proposed low carbon fuel standards apply to transportation fuels only in accordance with the Legislative intent. Therefore, home heating oil is not considered in the standard.

**A. Exemptions for Fuel Used in Specific Applications**

Fuel used in the following vehicles, equipment or engines is not subject to the Oregon low carbon fuel standards if the regulated party documents that the fuel is used exclusively for the exempt purpose listed below:

- **Fuels used in farm vehicles, farm tractors, implements of husbandry, and log trucks as identified by statute.** House Bill 2186 specifically exempts fuels used for these purposes from the low carbon fuel standards.

- **Fuels used in engines with special performance needs, including aircraft, racing vehicles, military tactical vehicles and military tactical support vehicles.** Certain types of specialized equipment have demanding performance characteristics and may have special fuel needs. Vehicles that operate at extreme temperatures, pressures or other conditions may be more likely to experience problems with fuel modifications that would go unnoticed in normal applications. Fuels in this category represent relatively small
volumes of transportation fuel. DEQ proposes that Oregon’s low carbon fuel standards exempt fuels used in these specialized applications to avoid any unintended effects.

- **Fuels used in oceangoing vessels and Class 1 locomotives.** Ocean-going vessels and Class 1 locomotives travel long distances and could easily change their purchasing patterns to avoid fuel subject to an Oregon low carbon fuel standard. Those changes could disrupt local fuel markets and have no emissions reduction benefit.

- **Fuels used in short-line locomotives will be exempt until at least 2017.** Questions remain about the nature of the short-line locomotive fuel distribution system including the volume of fuel affected or the degree to which distributors of short-line locomotive engine fuel would be dependent on purchased credits under a low carbon fuel standard. However, because of the nature of locomotive fuel distribution and the concerns about using biofuels in locomotive engines, distributors of locomotive fuel could be more dependent than other fuel sectors on credits under a low carbon fuel standard. In order to investigate these issues, DEQ proposes to exempt fuel used in short-line railroads until at least 2017. In the comprehensive review of the low carbon fuel standards program planned for 2016, DEQ will study this matter further and we will re-evaluate inclusion of fuel used in short line locomotives in the low carbon fuel standards at that time.

### C. Exemptions for Specific Alternative Fuels

- **Liquefied petroleum gas (also known as propane).** House Bill 2186 specifically authorizes the exemption of liquefied petroleum gas from the low carbon fuel standards.

- **Small Volume Fuels Producers.** This exemption could apply to start-up companies to help facilitate their success, or to existing small-scale producers to ease the burden of regulation given their small size and output. Producers of alternative fuels in small volumes may choose to opt-in to the low carbon fuel standards program to earn credits or deficits. If the producer opts in, regulated parties selling the alternative fuel can earn low carbon fuel credits or deficits from the sale of the fuel.
  - **Individual small-scale alternative fuel producers with 10,000 gasoline gallons equivalent annual production or less may** choose to opt-in to, or be exempt from the low carbon fuel standards if their total annual production is below 10,000 gasoline gallon equivalent per year. A fuel production volume of ten thousand gasoline gallon equivalent per year is the approximate volume of Oregon’s smallest producers of biofuels and this value could be taken to represent the level at which a biofuel business may become large enough to be included in a low carbon fuel standards program. Therefore this amount seems an appropriate threshold below which individual small-scale producers may be allowed to operate without having to comply with low carbon fuel standards requirements.

  - **Individual small-scale alternative fuel producers with 10,000 to 50,000 gasoline gallons equivalent annual production, used entirely by the fuel producer.** This exemption threshold is intended to facilitate the on-site production and use of low carbon fuels. For example, a farm owner may choose to produce biodiesel and operate their farm equipment with that fuel. Such an exemption allows for the use of self-produced fuels at the same location, and would not require the producer to meet the low carbon fuel standard.
- **Research, development or demonstration facilities that meet the definition in OAR 330-090-0105 62(a)(A-C).** This exemption is intended to allow for the research and development of new processes and facilities and is time-limited.

- **Fuels Used for Transportation in Small Volumes:** DEQ has the authority to exempt additional alternative fuels **used in Oregon** for transportation purposes in small volumes. For fuel/feedstock combinations that are used in Oregon in total aggregate volumes of less than 360,000 gasoline gallons equivalent per year, a producer or importer can request an exemption from the low carbon fuel standards. This exemption could ease the burden of regulation for new fuel start-up.

### D. Reporting Exempt Fuels

It is important that all fuels are tracked appropriately in order to have a reliable history of alternative fuel use and movement toward the 2022 goal. Providing exemptions to a low carbon fuel standard adds a layer of tracking to distinguish between exempt and nonexempt fuels, all within a regulatory framework. Transportation fuel housed in large storage tanks could be dispensed to both regulated and exempt uses. For example, on-road diesel fuel used for most semi-trucks would be subject to the low carbon fuel standards. However, if the same fuel were dispensed from the same tank to a logging truck, the fuel would be exempt. Similarly, non-road fuel used in construction equipment (i.e. cranes, backhoes, etc.) would be subject to low carbon fuel standards requirements while the same fuel used in farm equipment would not.

To differentiate the volume of fuels that properly qualify for exemption, DEQ’s compliance reporting will require regulated and opt-in parties to report exempt and non-exempt fuels. For a fuel volume to be considered exempt, compliance reporting will need to be supported by evidence that the fuel was used for one of the exempt uses. Such evidence could be provided upon delivery to a clearly exempt user (such as avgas delivered to an aircraft fuel tank at an airport) or by an affidavit indicating a fuel will be used for a qualifying category (as might be the case for the owner-operator of a log truck). The chief issue is that adequate documentation of a fuel’s use will be essential in the real world application of exemptions.

### Alternatives considered

DEQ and the advisory committee discussed exemptions several times. In addition, DEQ worked with stakeholders to identify practical methods for documenting and tracking sales of fuels to exempt uses such as farm vehicles and log trucks, to set reasonable exemption thresholds for small volume fuel producers, and to address issues associated with fuel used in locomotives.

Alternative 1: Exempt fuel used in harborcraft. *Arguments in favor — 1) Interstate rail and Columbia River/Snake River barge freight compete and there might be the perception of a competitive advantage afforded to interstate rail companies if fuel used in interstate rail is exempt and barges are not.*

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ii California’s LCFS exempts fuels used for transportation in volumes less than 3.6 million gasoline gallon equivalent (gge) per year. Oregon’s fuel use is approximately ten percent of California’s.
Alternative 2: Exempt fuel used in off-road construction equipment. *Arguments in favor — 1) This would make it more likely that exempt farm uses could obtain fuel that is not impacted by low carbon fuel standards.*

Alternative 3: Exempt fuel used in Intrastate rail. *Arguments in favor — 1) Distributors of fuels to intrastate rail may not be able to comply with the low carbon fuel standards. 2) Concerns exist about using biofuels in rail engines.*


Alternative 5: No exemptions for small volume fuel producers. *Arguments in favor — 1) Small volume fuel producers should not be treated any differently.*

**Rationale for DEQ Proposal**

DEQ worked with stakeholders to identify practical methods for documenting and tracking sales to exempt uses. DEQ’s proposal provides practical ways that a fuel can be exempted from the low carbon fuel standards.

**DEQ did not propose Alternatives 1 through 4** because the low carbon fuel standards do not regulate fuel users and are not a blending requirement. Because of this, and because of the low carbon fuel standards program deferrals and exemptions for fuel supply and price, these additional exemptions are not necessary.

**DEQ did not propose Alternative 5 because** DEQ sought to help small-scale producers by reducing regulatory burden given their small size and output. House Bill 2186 allows the Environmental Quality Commission to establish an exemption threshold for fuels. California’s low carbon fuel standards exemption threshold is 3.6 million gasoline gallon equivalent (gge) per year. Since Oregon’s fuel use is approximately ten percent of California’s, DEQ proposed an exemption threshold of 360,000 million gasoline gallon equivalent (gge) per year.

*Advisory committee input on this issue can be found in Appendix A.*

**4. Setting the Baseline Standards**

The goal of the low carbon fuel standard, as outlined in Section 6 (2) (b) of House Bill 2186 (see above), is to reduce the average carbon intensity of gasoline and diesel fuel 10 percent over a 10-year period. DEQ’s proposed low carbon fuel standards program currently uses a ten-year period of 2012 to 2022. To determine compliance meeting Oregon’s low carbon fuel standards, DEQ must establish two values for the carbon intensity of gasoline and gasoline substitutes, and diesel and diesel substitutes:

A. The average carbon intensity that must be met in each year between 2012 and 2022. This declining value is the low carbon fuel “standard”.

B. The baseline carbon intensity value for Oregon fuels in 2010, to which each subsequent year’s standard is compared to establish the required carbon intensity percentage reduction.
The baselines represent the starting point from which future carbon intensity reduction must be achieved. The low carbon fuel standards baselines reflect the average carbon intensity of Oregon’s 2010 fuel mix. DEQ has assumed an initial mix of Alaskan, Canadian, and other crude oil used in the production of petroleum coming to Oregon based on 2007 data. DEQ uses 2007 fuels data as a surrogate to estimate the 2010 baseline, because 2007 was the latest, most complete data set available when the work was being completed.

There are several key adjustments DEQ must make to establish the low carbon fuel standards baseline, and these issues are discussed in more detail below. In brief, the key adjustments are:

- The baseline estimates reflect the average carbon intensity of Oregon’s 2010 fuel mix. This includes an estimate of the relative amount of alternative fuels blended into gasoline and diesel fuels as a result of the existing Oregon and Portland renewable fuels standards:
  - Oregon’s renewable fuel standard requires that all regular and mid-grade gasoline sold in Oregon contain 10 percent ethanol (with some exceptions),
  - The state of Oregon requires that all diesel sold in Oregon contain two percent biodiesel (with some exceptions). In addition, the City of Portland, requires petroleum diesel fuel contain five percent biodiesel.

One particular issue of concern is that the use of some higher carbon intensity crudes might be increasing relative to the 2007 data, with the potential effect that 2007 data could underestimate the actual carbon intensity of the petroleum mix in 2010. To address this issue, DEQ used the most recent data available (2009) to account for higher carbon intensity crudes from Canada. (Canada National Energy Board website 2010, "Total Crude Oil Exports by Destination, 2009 Annual Report", 5)

**Fuels excluded from the baseline**

DEQ staff is not proposing to include the following in the baseline carbon intensity calculation because the use of these fuels for transportation in Oregon is currently very small and would have only a minor impact on the baseline:

- Electricity, CNG, LNG, biogas, or hydrogen used for transportation; and
- Biofuels used above the amounts required in 2010 by the Oregon renewable fuel standards.

**Baseline standards**

DEQ staff propose that the low carbon fuel standards program have one standard for gasoline and gasoline substitutes, and one for diesel and diesel substitutes. Credits generated or bought could be used on either the gasoline or the diesel side. The advisory committee had extensive discussions on this issue.
Alternatives considered

Alternative 1: A single baseline standard that averages the carbon intensities for gasoline and diesel and their substitutes together. When switches from gasoline to diesel occur in the light-duty passenger vehicle market, an Energy Economy Ratio (EER) could be applied. Arguments in favor — 1) A single baseline provides more compliance flexibility. 2) Oregon is a relatively small fuel consumer and we will not drive fuel innovation on our own. 3) Switching more of the light-duty fleet to diesel would have an immediate reduction in carbon emissions due to the EER of diesel as compared to gasoline. Reducing emissions in the short run is more valuable than in the long term. Having two separate standards will delay the reduction in emissions, which makes the reductions worth less. 4) The statute says to reduce the carbon intensity of the whole fuel pool, and therefore one standard is appropriate. 5) This alternative evaluates each fuel for greenhouse gas reductions and is therefore fuel-neutral.


Rationale for DEQ proposal

There are several reasons DEQ staff propose to use two baseline standards instead of one pool.

- The use of two baseline standards promotes the development of lower carbon intensity fuels for both gasoline and conventional diesel fuels.
- Having two baseline standards does provide some flexibility for regulated parties, since credits earned on the diesel side can be used on the gasoline side, and vice versa.
- The use of one baseline standard cannot be done properly without applying a diesel EER to light-duty diesel use. Applying a diesel EER to light-duty diesel fuel use will involve many unknowns with no practical way of tracking light-duty diesel use. The practical consequence of using a diesel EER in this manner is that conventional diesel used in light-duty applications would become a “low carbon fuel.” As a result, there might be less incentive for fuel producers to reduce the carbon intensity of alternatives to diesel fuel because the carbon intensity of diesel fuel used in light-duty applications would be below that of the 2022 standard. The one-pool option also achieves less carbon reductions.
- The use of two baseline standards eliminates the need to create and implement a complex mechanism for identifying and allocating carbon credits due to fuel switching from gasoline to diesel. Therefore, implementing two baseline standards is simpler than one.
- The use of two baseline standards avoids the potentially controversial point of granting conventional diesel fuel status as a “low carbon fuel.” The use of two baseline standards eliminates the concern that the low carbon fuel standards would promote increased toxic air pollution by incenting the increased use of diesel fuel (i.e. keeps the low carbon fuel standards program neutral on this point).
- The economic analysis showed little additional economic benefit from a “one pool” compliance scenario.
• Petroleum diesel is a baseline fuel; in widespread use at the time the low carbon fuel standards were authorized. The statute directs the Environmental Quality Commission to achieve reductions from baseline.

DEQ proposes to use 2010 as the baseline year, not 2007, because the baseline should reflect 2010 fuels.

DEQ did not propose including electricity, CNG, LNG, or biofuels used above renewable fuel standards required levels in the baselines. The use of these fuels is not currently tracked, and quantification would be difficult. Additionally, these fuels are used in small volumes and the impact on the baseline standards would be small.

_Advisory committee input on this issue can be found in Appendix A._

5. **Low Carbon Fuel Standards Compliance Schedule**

DEQ proposes to phase-in or “backload” the required low carbon fuels standards over the compliance period, with small reductions required in the early years of the program and larger reductions required in the last few years. This back-loaded schedule allows more time to develop lower carbon intensity fuels, and for the development and more widespread use of alternatively fueled vehicles and infrastructure.

<table>
<thead>
<tr>
<th>House Bill 2186</th>
</tr>
</thead>
<tbody>
<tr>
<td>SECTION 6. (2) (b) (b) The commission may adopt the following related to the standards, including but not limited to:</td>
</tr>
<tr>
<td>(A) A schedule to phase in implementation of the standards in a manner that reduces the average amount of greenhouse gas emissions per unit of fuel energy of the fuels by 10 percent below 2010 levels by the year 2020;</td>
</tr>
</tbody>
</table>

DEQ staff proposes to use two low carbon fuel standards, one for gasoline and gasoline substitutes, and one for diesel and diesel substitutes. The following tables show the required average carbon intensity of all fuels sold by regulated and opt-in parties in Oregon needed to meet the low carbon fuel standards compliance curve by program year, after taking deficits and credits into account.

Table 5 below shows the compliance schedule for gasoline and gasoline substitutes, and Table 6 below shows the compliance schedule for diesel and diesel substitutes. DEQ proposes to use a program timeline of 2012 to 2022.
Table 5: Low Carbon Fuel Standards Compliance Schedule for Gasoline and Gasoline Substitutes

<table>
<thead>
<tr>
<th>Year</th>
<th>Percent Reduction from Baseline</th>
<th>Required Average Carbon Intensity (gCO2e/MJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>Reporting Only (Gasoline Baseline is 90.38)</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>0.25 percent</td>
<td>90.15</td>
</tr>
<tr>
<td>2014</td>
<td>0.50 percent</td>
<td>89.93</td>
</tr>
<tr>
<td>2015</td>
<td>1.00 percent</td>
<td>89.48</td>
</tr>
<tr>
<td>2016</td>
<td>1.50 percent</td>
<td>89.02</td>
</tr>
<tr>
<td>2017</td>
<td>2.50 percent</td>
<td>88.12</td>
</tr>
<tr>
<td>2018</td>
<td>3.50 percent</td>
<td>87.22</td>
</tr>
<tr>
<td>2019</td>
<td>5.00 percent</td>
<td>85.86</td>
</tr>
<tr>
<td>2020</td>
<td>6.50 percent</td>
<td>84.51</td>
</tr>
<tr>
<td>2021</td>
<td>8.00 percent</td>
<td>83.15</td>
</tr>
<tr>
<td>2022 and subsequent years</td>
<td>10.00 percent</td>
<td>81.34</td>
</tr>
</tbody>
</table>

Figure 4: Low Carbon Fuel Standards Compliance Schedule for Gasoline and Gasoline Substitutes
Table 6: Low Carbon Fuel Standards Compliance Schedule for Diesel and Diesel Substitutes

<table>
<thead>
<tr>
<th>Year</th>
<th>Percent Reduction from Baseline</th>
<th>Required Average Carbon Intensity (gCO2e/MJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>Reporting Only (Diesel Baseline is 90.00)</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>0.25 percent</td>
<td>89.78</td>
</tr>
<tr>
<td>2014</td>
<td>0.50 percent</td>
<td>89.55</td>
</tr>
<tr>
<td>2015</td>
<td>1.00 percent</td>
<td>89.10</td>
</tr>
<tr>
<td>2016</td>
<td>1.50 percent</td>
<td>88.65</td>
</tr>
<tr>
<td>2017</td>
<td>2.50 percent</td>
<td>87.75</td>
</tr>
<tr>
<td>2018</td>
<td>3.50 percent</td>
<td>86.85</td>
</tr>
<tr>
<td>2019</td>
<td>5.00 percent</td>
<td>85.50</td>
</tr>
<tr>
<td>2020</td>
<td>6.50 percent</td>
<td>84.15</td>
</tr>
<tr>
<td>2021</td>
<td>8.00 percent</td>
<td>82.80</td>
</tr>
<tr>
<td>2022 and subsequent years</td>
<td>10.00 percent</td>
<td>81.00</td>
</tr>
</tbody>
</table>

DEQ took the following into account when considering what the low carbon fuel standards compliance schedule should be:
• Availability of biofuels due to the Federal, Oregon, and Portland renewable fuel standards;
• Future availability of plug-in hybrid electric, battery electric and flex-fuel vehicles; and
• Capacity and potential for production of low carbon fuels in general (see Appendix H: Fuels Assessment Discussion Paper).

DEQ proposes 2022 as the low carbon fuel standards horizon year, or the date by which the program will be fully phased in. The horizon year is an integral part of many aspects of the low carbon fuel standards, and influences assumptions about the compliance scenarios, as well as the proposed phase-in schedule and compliance obligations. House Bill 2186 (2009) states that the Environmental Quality Commission may adopt a phase-in schedule to reduce the average amount of greenhouse gas emissions in transportation fuel ten percent below 2010 levels by 2020. Because the statute is permissive, House Bill 2186 does not require 2020 as a horizon year for Oregon’s low carbon fuel standard. Given this flexibility, DEQ intends to use a horizon year of 2022 for our program assessment for the following reasons:

• House Bill 2186 anticipates an approximate program phase-in period of ten years. Between now and 2012, DEQ must complete the advisory committee process, report, and draft rule; vet these materials with the public, stakeholders and legislature; and conduct a public rulemaking process. Given that schedule, it is likely that the Environmental Quality Commission would not adopt a final low carbon fuel standards rule until December 2011. A horizon year of 2022 provides a reasonable timeframe in which to successfully launch the program and meet the ten percent emission reduction requirement over roughly a ten-year period.

• The federal Renewable Fuel Standard also uses a horizon compliance year of 2022.

• The State of Washington is contemplating 2023 or 2024 as the horizon year for their program. Using 2022 for Oregon would put the compliance end-points for both programs reasonably close to each other.

• Using 2022 allows an additional two years to develop alternative fuels infrastructure, use and production in Oregon to meet the low carbon fuel standards.

• Regardless of whether 2020 or 2022 is used in the program evaluation phase, the low carbon fuel standards will be designed to achieve the same amount of emission reduction, (i.e. a ten percent reduction in greenhouse gas emissions from 2010 levels).

DEQ may provide an additional reporting year to address implementation issues discovered in the 2012 reporting year. This would move the first compliance year from 2013 to 2014 and the horizon year to from 2022 to 2023. The start date of the program could also be postponed in order to secure implementation resources.

Alternatives considered

Alternative 1: 2010-2020 program timeline. Arguments in favor — 1) It makes sense to be on the same timeline as California. 2) There is public support for reducing pollution and breaking oil dependence. 2020 is a workable horizon year and brings greenhouse gas
pollution reductions sooner. 3) A delay in program implementation means a delay in investment opportunities and greenhouse gas emission reductions for Oregon.

Alternative 2: If timeline is delayed from 2010 through 2020 to a later year, the projected greenhouse gas pollution reductions lost due to the delay should be made up in subsequent years. **Arguments in favor — 1) This would assure that the low carbon fuel standards achieves desired impact.**

Alternative 3: 2014-2024 program timeline. **Arguments in favor — 1) It makes sense to be on the same timeline as Washington (note: Washington is still considering a timeline.)**

**Advisory committee input on this issue can be found in Appendix A.**

**Fuel Carbon Intensity Lookup Table**
A central part of Oregon’s low carbon fuel standards program and rules will be a lookup table listing carbon intensities for the fuels most likely to be supplied in Oregon. A carbon intensity value will be specified for each fuel pathway, and in some cases, sub-pathways. A fuel pathway refers to the whole process of producing and using a fuel, including: extracting or growing the feedstock; transporting the feedstock to the refinery; refining the feedstock into a fuel; transporting and storing the finished fuel; and combusting the fuel in a vehicle. Some fuels have statewide average carbon intensities, while others have fuel pathways based on feedstock, source, and process used. See page 123 for a description of how carbon intensity is calculated. **Appendix B: Lifecycle Analysis** contains detailed information on carbon intensity calculation methods. As new processing technologies and feedstocks emerge, new carbon intensities will need to be established and the carbon intensity lookup table will need to be updated. It is critical that the carbon intensity lookup table accurately reflects fuels current sold in Oregon. See page 78 for updates to and adding carbon intensities to the lookup table. For the carbon intensities for gasoline and gasoline substitutes, please see Table 7 on page 77. For the carbon intensities for diesel and diesel substitutes, please see Table 8 on page 78.

The carbon intensity lookup tables below includes a column for indirect land use change and other indirect effects, although DEQ has not yet adjusted the carbon intensity numbers to account for indirect effects. Oregon intends to review indirect land use change and other indirect effects in the 2014 and 2016 low carbon fuel standards program reviews. When there is adequate calculation of indirect land use change or other indirect effects, DEQ intends to adjust the relevant fuel carbon intensity values accordingly. Indirect effects might not be addressed at the same time as indirect land use change, depending on the development of the science. See page 135 for a discussion on indirect land use change and other effects.

The carbon intensity tables also include a column for energy economy ratios (EER). Please see page 139 for a description of how EERs are calculated, and page 85 for how EERs are used to calculate credits and deficits.
<table>
<thead>
<tr>
<th>Fuel</th>
<th>Pathway Description</th>
<th>Carbon Intensity Values (gCO2e/MJ&lt;sup&gt;1&lt;/sup&gt;)</th>
<th>Direct Emissions</th>
<th>Land Use Change or Other Indirect Effect&lt;sup&gt;2&lt;/sup&gt;</th>
<th>EER&lt;sup&gt;3&lt;/sup&gt; Applied</th>
<th>Final</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>Based on a weighted average of gasoline supplied to Oregon</td>
<td>92.34</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>92.34</td>
</tr>
<tr>
<td>Ethanol from Corn</td>
<td>Ethanol produced in the Midwest from MW grown corn. MW Average production&lt;sup&gt;4&lt;/sup&gt;, GREET Default.</td>
<td>64.82</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>64.82</td>
</tr>
<tr>
<td></td>
<td>NW production, MW Corn. Dry Mill, NG&lt;sup&gt;5&lt;/sup&gt;, Wet DGS&lt;sup&gt;6&lt;/sup&gt;</td>
<td>53.79</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>53.79</td>
</tr>
<tr>
<td>Ethanol from Sugarcane</td>
<td>GREET defaults except transportation</td>
<td>26.44</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>26.44</td>
</tr>
<tr>
<td>Cellulosic Ethanol</td>
<td>NW Farmed Trees</td>
<td>15.54</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>15.54</td>
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<tr>
<td></td>
<td>Wheat Straw</td>
<td>20.90</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>20.90</td>
</tr>
<tr>
<td></td>
<td>Forest Residue GREET Defaults for gasification</td>
<td>20.49</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>20.49</td>
</tr>
<tr>
<td></td>
<td>Mill Waste</td>
<td>12.31</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>12.31</td>
</tr>
<tr>
<td>Compressed Natural Gas</td>
<td>North American natural gas delivered via pipeline; compressed in OR</td>
<td>70.22</td>
<td>TBA</td>
<td>1</td>
<td></td>
<td>70.22</td>
</tr>
<tr>
<td>(CNG)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Electricity</td>
<td>Oregon average electricity mix 2012</td>
<td>154.98</td>
<td>TBA</td>
<td>4.1</td>
<td>37.80</td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2013</td>
<td>154.98</td>
<td>TBA</td>
<td>4.0</td>
<td>38.74</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Oregon average electricity mix 2014</td>
<td>154.98</td>
<td>TBA</td>
<td>3.9</td>
<td>39.73</td>
<td></td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2015</td>
<td>154.98</td>
<td>TBA</td>
<td>3.8</td>
<td>40.78</td>
<td></td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2016</td>
<td>154.98</td>
<td>TBA</td>
<td>3.7</td>
<td>41.88</td>
<td></td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2017</td>
<td>154.98</td>
<td>TBA</td>
<td>3.6</td>
<td>43.00</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Oregon average electricity mix 2018</td>
<td>154.98</td>
<td>TBA</td>
<td>3.5</td>
<td>44.28</td>
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<td></td>
<td>Oregon average electricity mix 2019</td>
<td>154.98</td>
<td>TBA</td>
<td>3.4</td>
<td>45.58</td>
<td></td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2020</td>
<td>154.98</td>
<td>TBA</td>
<td>3.3</td>
<td>46.96</td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2021</td>
<td>154.98</td>
<td>TBA</td>
<td>3.2</td>
<td>48.43</td>
<td></td>
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<tr>
<td></td>
<td>Oregon average electricity mix 2022</td>
<td>154.98</td>
<td>TBA</td>
<td>3.1</td>
<td>49.99</td>
<td></td>
</tr>
</tbody>
</table>

<sup>1</sup> gCO2e/MJ means grams of carbon dioxide equivalent per mega joule

<sup>2</sup> Indirect Land Use Change or Other Indirect Effect: the value for indirect land use change or any other indirect effects have not been established, but will be considered in the low carbon fuel standards 2014 review.

<sup>3</sup> EER means Energy Economy Ratio

<sup>4</sup> Midwest average refers to the source of electricity used to refine the fuel

<sup>5</sup> NG refers to the energy source used to refine the fuel

<sup>6</sup> DGS means Dairy Grain Solubles
Oregon has not completed carbon intensity calculations for fuels that are not used in Oregon for transportation in large quantities.

### Table 8: Carbon Intensity Lookup Table for Diesel and Diesel Substitutes

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Pathway Description</th>
<th>Carbon Intensity Values (gCO2e/MJ)</th>
<th>Direct Emissions</th>
<th>Land Use Change or Other Indirect Effect</th>
<th>EER&lt;sup&gt;3&lt;/sup&gt; Applied</th>
<th>Final</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ultra Low Sulfur Diesel</td>
<td>Based on a weighted average of diesel supplied to Oregon</td>
<td>91.53</td>
<td>TBA</td>
<td>1</td>
<td>91.53</td>
<td></td>
</tr>
<tr>
<td>Renewable Diesel</td>
<td>Northwest Production, Midwest soy oil</td>
<td>21.66</td>
<td>TBA</td>
<td>1</td>
<td>21.66</td>
<td></td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Midwest Soybeans. GREET default Midwest Average&lt;sup&gt;4&lt;/sup&gt; production, biodiesel shipped by rail to Oregon</td>
<td>19.99</td>
<td>TBA</td>
<td>1</td>
<td>19.99</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Northwest Canola</td>
<td>27.31</td>
<td>TBA</td>
<td>1</td>
<td>27.31</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Yellow Grease Average.</td>
<td>10.28</td>
<td>TBA</td>
<td>1</td>
<td>10.28</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tallow Average</td>
<td>16.85</td>
<td>TBA</td>
<td>1</td>
<td>16.85</td>
<td></td>
</tr>
<tr>
<td>Compressed Natural Gas (CNG)</td>
<td>Pipeline NG compressed to CNG at the refueling stations</td>
<td>70.22</td>
<td>TBA</td>
<td>0.94</td>
<td>74.70</td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Oregon average electricity mix</td>
<td>154.98</td>
<td>TBA</td>
<td>2.70</td>
<td>57.4</td>
<td></td>
</tr>
</tbody>
</table>

<sup>1</sup> gCO2e/MJ means grams of carbon dioxide equivalent per mega joule

<sup>2</sup> Indirect Land Use Change or Other Indirect Effect: the value for indirect land use change or any other indirect effects have not been established, but will be considered in the low carbon fuel standards 2014 review.

<sup>3</sup> EER means Energy Economy Ratio

<sup>4</sup> Midwest average refers to the source of electricity used to refine the fuel

Oregon has not completed carbon intensity calculations for fuels that are not used in Oregon for transportation in large quantities.

*Advisory committee input on this issue can be found in Appendix A.*

### 6. Updating or Adding to the Carbon Intensity Lookup Table

Several fuel production/feedstock pathways will be included in the carbon intensity lookup table in the rules. However, as new fuels, feedstocks, or production processes arise, new carbon intensities will need to be added to the table. In addition, some fuels will have a statewide average carbon intensity, which might change over time.
A. Updating Existing Statewide Average Carbon Intensities in Lookup Table

DEQ staff proposes that the statewide carbon intensities for gasoline, diesel, electricity and compressed fossil natural gas derived from North American natural gas delivered in a pipeline be updated, at a minimum, every three years. The update will reflect any changes that might have occurred in the statewide average carbon intensity of these fuels. In addition, if the statewide average changes by more than 5gCO2e/MJ or 10 percent, DEQ will update the statewide average carbon intensity number for that fuel. Individual producers of these fuels must use the statewide average listed in the carbon intensity lookup table (i.e. no individual carbon intensity numbers).

- The one exception is that an electricity provider who only provides electricity for transportation and is exempt from Oregon Public Utility Regulation by ORS 757.005 (1)(b)(G) can obtain a carbon intensity number specific to the electricity they supply. If an electricity provider has established an individual carbon intensity through this process, they can update their carbon intensity if it changes by more than 5gCO2e/MJ or 10 percent.

See page 76 for the carbon intensity lookup table.

Alternatives considered:

Alternative 1: Update carbon intensities more often than every three years. Arguments in favor — 1) Keeps the carbon intensity lookup table more accurate. In addition, if a carbon intensity changes, emission reductions could be lost.

Rationale for DEQ Proposal

Statewide carbon intensities are not expected to change drastically each year. However, if there is a significant change, DEQ is not precluded from updating carbon intensities more frequently. Therefore, updating statewide carbon intensities at a minimum of every three years will keep the carbon intensity lookup table up to date.

B. Adding a New Carbon Intensity to the Lookup Table (New Fuel Pathways Process)

Individual fuel producers of biogas, LNG, hydrogen, ethanol, biomass-based diesel, and any other fuel that does not have a statewide carbon intensity will need to have a carbon intensity specific to the fuel production pathway. If there is an appropriate carbon intensity number already in one of the carbon intensity lookup tables that matches a fuel producer’s feedstock and production process, then a producer can, if DEQ approves, use that carbon intensity number. If not, the producer will need to add a carbon intensity to the lookup table through the process described below, and will need to provide documentation of carbon intensity values to DEQ for verification and approval.

There are two situations in which a new carbon intensity can be added to the carbon intensity lookup table (See Figure 6 on page 81):
1. New Fuels or Feedstock
DEQ proposes that fuel producers who are introducing a new fuel or feedstock will have to establish a new carbon intensity for their pathway using OR-GREET, which DEQ intends to make public prior to rule implementation.

2. New or Improved Production Processes
Fuel producers who are introducing a new or improved process for a sub-pathway (fuel/feedstock combination) that already exists in the carbon intensity table will need to determine if the carbon intensity for their process is significantly different from the carbon intensity already in the table. To determine if the difference is significant, DEQ staff propose a set of minimum thresholds that act as a screening tool. If a fuel producer meets both thresholds, then the fuel producer can establish a new carbon intensity. If a fuel producer cannot meet both of these thresholds, then they cannot establish a new carbon intensity, and must use the carbon intensity pathway that most closely describes their process, as approved by DEQ.

The thresholds are:

a) **Minimum Thresholds for Changes in Carbon Intensity:** The well-to-tank carbon intensity of the new process, compared to the existing process for the same fuel-feedstock combination in the lookup table, changes more than 5.0 g CO2E/MJ or 10 percent, whichever is less; **AND**

b) **Minimum Fuel Volume Thresholds:** The regulated party is able and intends to provide more than one million gasoline gallon equivalents per year of the fuel in Oregon. (The second criterion does not apply if all providers of that fuel supply less than one million gasoline gallon equivalents per year in total.)

Once a new carbon intensity is calculated, the fuel producer will submit it to DEQ for approval. Upon approval, the fuel producer can immediately begin using the number. The lookup table will be updated periodically, at which point it becomes eligible for other producers to use, if appropriate.

If a fuel producer’s process changes so that the carbon intensity increases by more than 5.0 g CO2E/MJ or 10 percent, the fuel producer must notify DEQ and obtain a new carbon intensity for all fuel types they produce.
Alternatives considered

Alternative 1: If the carbon intensity improves more than 5.0 g CO2E/MJ, allow a carbon intensity to be added to table. *Arguments in favor — 1) Consistency with California Air Resources Board.*

Alternative 2: Adding a carbon intensity at a producer’s request. *An argument in favor — 1) For funding purposes, a pilot-scale producer needs to be able to get a carbon intensity number for their commercial-scale facility.*

Rationale for DEQ Proposal

DEQ proposal for adding new carbon intensities to the lookup table will encourage and reward innovation and to make sure that the carbon intensity lookup table accurately reflects current fuels sold in Oregon.

In order to manage the workload for evaluating and approving applications, DEQ set minimum thresholds to ensure that the new carbon intensity to be added to the table is significantly different than existing carbon intensity values, and to ensure that commercial quantities of fuel will be supplied in Oregon to make the effort worthwhile.

DEQ believes that the hybrid approach of allowing a new carbon intensity to be added with either a 5.0 g CO2E/MJ or 10 percent change in carbon intensity (whichever is less) is fairer than either setting a single value threshold or setting a straight percentage threshold. After advisory committee comment, DEQ added a provision that if carbon intensity increases a certain amount a fuel producer needs to notify DEQ and get a new carbon intensity.
C. High Carbon Intensity Crudes

In evaluating what petroleum crudes will be available in the future, there is much concern over sources that need increasing amounts of energy to make them available for processing, and sources with high rates of natural gas flaring. Specifically for Oregon fuels, as traditional crude supplies in Alaska decrease, crude from Canadian tar sands will likely increase. Likewise, crude extracted in other countries may have a higher energy input or flaring rates, and thus have a higher carbon intensity. DEQ presented several options for how to address high carbon intensity crudes. DEQ proposes to update the carbon intensity values lookup table for gasoline and diesel a minimum of every 3 years to reflect the “current” state of petroleum crudes. This will account for any increased amounts of high carbon intensity crudes from existing areas as well as any new high carbon intensity crude sources.

Alternatives considered

Alternative 1: Always use carbon intensity in the lookup table for petroleum crudes. 
*Arguments in favor — 1) This alternative is the least administratively burdensome, and provides the most regulatory certainty. 2) All crude should be treated equally. 3) This alternative does not create an incentive for crude shuffling.*

Alternative 2: Fuel producer adds a new carbon intensity to lookup table for any fuel produced from high carbon intensity crude oils. *Arguments in favor — 1) Fair method of accounting for increase in carbon intensity due to crude sources used in fuel production. 2) Provides more regulatory certainty. 3) Other alternatives do not have any incentive for an individual company to avoid new use of high carbon intensity crudes. 4) Crude shuffling is not likely in Oregon because we are a small part of the market.*

Alternative 3: Use California Air Resources Board’s method. [Note: DEQ considered this alternative, but did not present it to the advisory committee because it is extremely complex and administratively resource intensive] *Arguments in favor — 1) This accounts for carbon intensity as accurately as DEQ’s proposal does, but holds individual fuel producers responsible for use of high carbon intensity crudes instead of accounting for high carbon intensity crudes with a statewide average. 2) Consistency with California. 3) Crude shuffling is not a likely result of an Oregon low carbon fuel standards because Oregon is a small part of the regional petroleum market.4) Environmental integrity and efficacy of program.5) This alternative treats petroleum the way the biofuels are treated in requiring a new carbon intensity for fuels that are significantly different; fuels should be treated consistently.*

Alternative 4: Update carbon intensity for gasoline and diesel more frequently than every 3 years. *Arguments in favor — 1) This would keep the table more accurate and ensure that carbon intensity reductions are obtained. 2) Reports suggest that tar sand production might ramp up quickly. 3) Environmental integrity and efficacy of program. 4) Low carbon fuel producers need to know how large the market will be from year to year. 4) If high carbon intensity crudes are not tracked carefully, there is a potential that low carbon fuel standards will lose ground in meeting carbon intensity goals.*
Rationale for DEQ Proposal

Accurately accounts for increases (or decreases) in carbon intensity in gasoline and diesel fuels with a minimum of administrative burden. If carbon intensities change drastically, DEQ could update them more frequently, but would not be bound to make updates more frequently for small changes in carbon intensity. Ideally, DEQ would update more frequently than every three years if needed. DEQ’s proposal will not encourage crude shuffling as much as alternatives 2 or 3 would.

Advisory committee input on this issue can be found in Appendix A.

7. Credits and Deficits

A. Introduction

Compliance with low carbon fuel standards would be demonstrated through the calculation of carbon intensity credits. DEQ proposes that a fuel sold in Oregon by regulated or opt-in parties with a carbon intensity that is less (lower) than the required low carbon fuel standard for that year would generate credits. A fuel sold in Oregon with a carbon intensity that is higher than the low carbon fuel standard for that year would generate deficits. At the end of the year, a regulated party would reconcile credits and deficits to demonstrate compliance with the low carbon fuel standards.

Deficits are generated when a fuel is imported into or produced in Oregon (See Figure 7 on page 84). Fuels with a carbon intensity less than the low carbon fuel standards for that year will earn credits. A credit is generated (i.e. it can be sold, banked, or used) when the fuel is used (electricity, CNG, LNG, hydrogen, biogas) or delivered to a retail facility or end user in Oregon (for biofuels). (See Figure 8 on page 85)

A credit is not a property right, but is a regulatory implement. When DEQ adjusts the carbon intensity of fuels to include indirect land use change, DEQ will also adjust any banked credits derived from cropped fuels to reflect the change. The result would be that a banked credit for fuel made from cropped biofuels might be reduced to some percentage of a credit (see discussion on banked credits on page 87). Fuel credits made from waste would not be affected when Oregon’s carbon intensities are adjusted to account for indirect land use change. DEQ intends to also adjust the carbon intensity of fuels to include other indirect effects, and will also adjust credits appropriately at that time.

For detailed credit and deficit calculation methodology and for examples, please see Appendix J: Credit and Deficit Calculations.

i. Generation of Deficits

Deficits are generated when a fuel is first produced or imported into Oregon (for fuels with a carbon intensity higher than the low carbon fuel standards). Some of this fuel, however, will be sold out of state. In order to subtract this volume from their compliance obligation, the regulated party who has the compliance obligation for that fuel would need to possess documentation that the fuel was exported out of Oregon.

Rationale for DEQ Proposal
This will include all appropriate fuel in the low carbon fuel standards. See Figure 7 on page 84.

**Figure 7: Generation of Low Carbon Fuel Deficits**

**ii. Generation of Credits**

Credits can be sold, banked, or used once the fuel is used or supplied to a retail facility or end user. The opt-in or regulated party reporting a credit would need to possess documentation that the fuel was:

- Used (for electricity, CNG, LNG, hydrogen, or biogas); or
- Supplied to a retail facility or end user in Oregon (for biofuels). See Figure 8 on page 85.

**Rationale for DEQ Proposal**

DEQ proposes this as the best way to ensure that credits sold or banked are valid.
B. Overview of How to Calculate Credits and Deficits

Credits and deficits will be calculated and expressed as metric tons of CO$_2$ equivalent. For purposes of understanding how credits and deficits would be calculated, we have provided an overview of the steps involved below.

Calculating credits and deficits involves several steps because the low carbon fuel standards covers fuels with different energy intensities, including liquid and non-liquid fuels. Carbon intensity of fuels is expressed in grams of carbon dioxide equivalent per megajoule (g CO$_2$ E/MJ). This is so that the lifecycle emissions of different types of liquid and non-liquid fuels can be compared. In order to translate a volume of fuel sold at certain carbon intensity into credits and deficits expressed in metric tons of CO$_2$ equivalent, several steps are involved. Oregon’s final rule regarding calculation of credits and deficits will address issues such as the number of significant digits and rounding.

For details, formulas, and examples of credit and deficit calculations, please refer to *Appendix J: Credit and Deficit Calculations.*

**Step 1: Calculate the number of megajoules (MJ) of energy in the fuel sold**
Explanation: Because different liquid fuels have different energy densities, or are in non-liquid form, we cannot just use the volume of fuel in gallons. To put all of the liquid and non-liquid fuels on equal footing, megajoules are used instead of gallons, standard cubic feetiii (scf), or kilowatt-hours (KWh). A table with energy densities in megajoules per unit of fuel is used to calculate the number of megajoules of energy in the fuel sold.

Step 2: Account for energy economy ratios, if necessary

Explanation: Different types of vehicles use the energy in fuel more or less efficiently. For example, on average, an electric car will go four times farther than a gasoline vehicle on the same number of megajoules, while a heavy duty natural gas vehicle will go only 94 percent as far as a diesel heavy duty vehicle on the same number of megajoules. The Energy Economy Ratios (EERs) are used to adjust credits taking these differences into account. Please see page 139 for a discussion of EERs and a table of EERs DEQ staff is proposing to use in a low carbon fuel standard.

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

Explanation: Comparing the low carbon fuel standard for the year in question to the carbon intensity of a given fuel will tell us whether selling the fuel will generate credits or deficits, and will also indicate whether selling the fuel will generate a relatively large or small number of credits or deficits.

Step 4: Calculate the credits/deficits in grams of CO₂ equivalent

Explanation: Credits and deficits are expressed in volumes of greenhouse gas emissions, where credits show the emissions “saved” by selling a low carbon fuel compared to selling a fuel with a carbon intensity that exactly meets the low carbon fuel standard for that year. Deficits, by comparison, show the “excess” emissions incurred by selling a fuel whose carbon intensity is higher than the low carbon fuel standard, compared to selling a fuel that exactly meets the standard for that year. In this step, emissions are calculated in grams of CO₂ equivalent, while in the next step emissions are converted into metric tons of CO₂ equivalent. CO₂ equivalent, or CO₂E, is a unit of measurement that combines CO₂ and other greenhouse gases like methane and nitrous oxide into one number. It describes, for a given mixture and amount of greenhouse gases, the amount of CO₂ that would have the same climate change potential.

Step 5: Convert the grams of CO₂ equivalent into metric tons of CO₂ equivalent

Explanation: Greenhouse gas emissions are most commonly expressed in metric ton units. There are 1,000,000 grams per metric ton (g/metric ton), so the final step in the calculation is to divide the result from step 4 by 1,000,000.

iii A standard cubic foot (abbreviated as scf) is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and 14.696 psi of pressure.
C. Program Elements

a. Low carbon fuel credit banking

DEQ staff propose that low carbon fuel credits may be banked for future use. This will permit fuel providers to achieve early reductions under the program and allow greater flexibility in managing compliance in coming years. Being able to carry credits forward should also improve the stability of the credit market as the value of credits would not expire. Credits may also be bought and sold among regulated parties, which will allow further flexibility and enable market forces to help regulated parties achieve greenhouse gas reductions in the most efficient manner.

DEQ staff propose to add indirect land use change to the carbon intensity of fuels made from crops at some point in the future. At that time, DEQ will adjust any banked credits generated from fuels made from crops to reflect the new carbon intensity. For example, if DEQ added a hypothetical indirect land use change of 16 gCO2e/MJ to the carbon intensity of Midwest corn ethanol to account for indirect land use change at some point in the future, the carbon intensity of Midwest corn ethanol would be as follows:

<table>
<thead>
<tr>
<th>Carbon Intensity (gCO2e/MJ)</th>
<th>Percent of Total Carbon Intensity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Carbon Intensity</td>
<td>64.82</td>
</tr>
<tr>
<td>Indirect Carbon Intensity</td>
<td>16.00</td>
</tr>
<tr>
<td>Total</td>
<td>80.82</td>
</tr>
</tbody>
</table>

Because the indirect carbon intensity is 20 percent of the new total carbon intensity, the value of any banked credits from Midwest corn ethanol will be decreased 20 percent when the carbon intensity of all fuels is adjusted to reflect the carbon intensity of indirect land use change. DEQ would only adjust banked credits.

Low carbon fuel credits generated from biofuels made from waste would not be adjusted, since biofuels made from waste do not have indirect land use change effects.

Alternatives considered

Alternative 1: No banking of credits.

Alternative 2: Credits expire after a certain number of years.

Arguments in favor of alternatives 1 and 2: 1) Credit banking could dilute the program in later years if a big credit surplus builds up. 2) With unlimited credit banking, a regulated party could hoard credits.

Alternative 3: No banked credits until indirect land use change is added.
Rationale for DEQ Proposal

Credit banking will permit fuel providers to achieve early reductions under the program and allow greater flexibility in managing compliance in coming years. The ability to carry credits forward should also improve the stability of the credit market, as the value of credits would not expire.

b. Credits “borrowed” against future emission reductions

DEQ proposes to NOT allow low carbon fuel credit “borrowing” against future emission reductions (i.e., selling credits that would be generated in the future). Some regulated parties commented during development of California’s low carbon fuel standards that they should be allowed to “borrow” credits from future emissions reductions. Under such a mechanism, borrowed credits could be sold to generate funds for equipment or process improvements that would in turn produce reductions in carbon intensity. DEQ considers this to be an intriguing concept but does not have a reliable way to ensure that the reductions signified by borrowed credits are actually achieved.

c. Third parties

DEQ proposes that non-regulated third parties would NOT be permitted to purchase or own low carbon fuel credits. Only regulated or opt-in parties could purchase low carbon fuel credits. This prohibition is meant to ensure that an adequate number of credits are available within the program, and that third parties do not speculate in the low carbon fuel credit market.

d. Small and large low carbon fuel deficits

1. Small Low Carbon Fuel Deficits: DEQ proposes that “small” low carbon fuel deficits remaining at the end of a compliance period must be rectified within the next compliance year. In most cases, deficits will need to be rectified at the end of the compliance year. However, for small deficits, DEQ proposes a one-year grace period. DEQ proposes that a “small” deficit be defined as a deficit remaining at the end of a compliance year that is 10 percent or less than the total deficits generated by that regulated party during the compliance year. For example, if a regulated party earned 20,000 total deficits in a compliance year, but had only 19,000 credits, they would have 1,000 net deficits remaining (after reconciling credits and deficits). The 1,000 remaining deficits are five percent of the 20,000 total deficits, and thus are less than 10 percent of the total deficits, and can be carried over and reconciled the following year. This approach allows some flexibility for regulated parties without compromising the integrity of the program, and this flexibility could contribute toward minimizing compliance costs for regulated parties. During the last year of the program, no credit carryover would be allowed.

2. Large Low Carbon Fuel Deficits: DEQ proposes that large low carbon fuel deficits, defined as deficits greater than 10 percent of the total deficits generated by that regulated
party during the year, cannot be carried over. The deficiency must be reconciled at the end of that compliance period.

e. Can any type of carbon credits from other programs be used for the low carbon fuel program?

DEQ proposes that only low carbon fuel credits could be used to meet the low carbon fuel standard. This means that no other carbon offset, or other type of carbon credit could be used in the low carbon fuel standards program.

There currently is no broader regulatory greenhouse gas reduction program that affects Oregon, either at the state or federal level. There are, however, markets for carbon offsets. Not allowing carbon offsets or credits from other greenhouse gas reduction programs to be used for the low carbon fuel standards is intended to ensure that greenhouse gas reductions are achieved within the transportation fuel sector and to stimulate the use of low-carbon intensity fuels that are locally available.

f. How would fuel sold to exempt users be excluded from credit and deficit calculations?

The legislature exempted fuel used in farm uses and logging trucks from the low carbon fuel standard. In addition, there are other uses (military, airplane, racing cars, oceangoing vessels, trains, etc.) that DEQ also proposes to exempt from the regulation for a variety of reasons (see exemptions discussion on page 66). The low carbon fuel standards need to remain neutral as far as low carbon fuels and exempt uses, and make sure there is not an incentive created to sell more or less low carbon fuel to exempt uses.

If a regulated party sells a delivery (e.g., a quantity of fuel on a single invoice or bill of lading, etc., or a delivery of blended fuel, regardless of how many invoices there are for that delivery) of fuels to an exempt user, DEQ proposes that the regulated party has two options for calculating credits and deficits for that delivery of fuel during the compliance period:

- Exclude the entire delivery of fuel from credit and deficit calculations.
- Exclude none of the delivery of fuel from credit and deficit calculations.

For example, this would mean that if a regulated party sells a delivery of fuel to an exempt user that includes gasoline with 10 percent ethanol with a carbon intensity that is less than the low carbon fuel standard (which will therefore earn credits), then that regulated party has two choices:

- Exclude the entire delivery of fuel from credit and deficit calculations, claiming neither the deficits from the gasoline nor the credits from the ethanol; **OR**
- Exclude none of the delivery of fuel from credit and deficit calculations, claiming both the deficits from the gasoline AND the credits from the ethanol.

**Alternatives considered**

Alternative 1: Do not allow credit for any fuel sold to exempt fuel uses. *Arguments in favor — 1) Some exempt users are worried about blended biofuels.*
Rationale for DEQ Proposal

The low carbon fuel standard is not a requirement for fuel blending. Some exempt fuel users already use biofuels. The low carbon fuel standards need to remain neutral as far as low carbon fuels and exempt uses, and make sure there is not an incentive created to sell more or less low carbon fuel to exempt uses.

**g. Can low carbon fuel credits still accrue during the time that exemptions or deferrals are in place?**

House Bill 2186 allows for exemptions and deferrals to ensure that the price of gasoline and diesel in Oregon remain competitive with other states, and deferrals to ensure an adequate fuel supply.

DEQ proposes that during the time that exemptions or deferrals are in place, credits would still be allowed to accrue. There are two main reasons for allowing this:

1. The use of exemptions or deferrals most likely means that there are currently not enough low carbon fuels to meet the need. Allowing credits to accrue during times of exemptions and deferrals may be helpful to address a scarcity of low carbon fuels.

2. Allowing credits to accrue during times of exemptions or deferrals provides more regulatory certainty for investors in low carbon fuels.

Alternatives Considered

Alternative 1: Credits cannot accrue during deferral periods.

Rationale for DEQ Proposal

The use of exemptions or deferrals most likely indicates a limited supply of low carbon fuels to meet the demand. Allowing credits to accrue during times of exemptions and deferrals may be helpful to address a scarcity of low carbon fuels.

Allowing credits to accrue during times of exemptions or deferrals provides more regulatory certainty for investors in low carbon fuels.

*Advisory committee input on this issue can be found in Appendix A.*

For detailed credit and deficit calculation methodology and for examples, please see *Appendix J: Credit and Deficit Calculations.*

8. **Buying and Selling Credits**

Fuel sold in Oregon by a regulated or opt-in party with a carbon intensity that is less (lower) than the required low carbon fuel standard would generate low carbon fuel credits. These credits can be banked and sold to regulated parties who may need credits as part of their overall compliance strategy. DEQ and its advisory committee discussed options for documenting, tracking, and verifying low carbon fuel credits, and well as options for how a credit market might work. These are discussed below.
As described above, regulated and opt-in parties would report low carbon fuel credits generated in their annual compliance report, as well as the source and number of any credits bought or sold during the compliance period. At the end of the compliance year, DEQ will compare credits bought with credits sold based on those annual compliance reports. For example, if Company A reported to DEQ that they purchased 10 credits from Company B, and Company B reported to DEQ that they sold 10 credits to Company A, DEQ would compare the two reports and verify that the number of credits claimed matched the number of credits sold. DEQ also proposes to make available to regulated and opt-in parties a list of regulated and opt-in parties, and for fuel producers, the total credit generation capacity of each production plant that supplies fuel to Oregon, given the capacity of the plant, the carbon intensity of the fuel produced, and the low carbon fuel standard for that year.

DEQ staff propose that if a regulated or opt-in party sells a credit that is invalid, the credit seller will need to provide a valid credit to make up for the invalid one, and will be subject to enforcement. DEQ would not take enforcement against the credit buyer, provided they had verified that the credit seller was on DEQ’s regulated/opt-in party list; the carbon intensity of the fuel from that producer matches the carbon intensity for that fuel producer on DEQ’s website; and that the number of credits purchased did not exceed the credit generation capacity of each seller’s production plant. Credits would not be verified by DEQ prior to sale.

DEQ staff propose that regulated and opt-in parties not submit quarterly reports to DEQ. Annual reports would be required, and DEQ would make aggregated program information available.

**Alternatives considered**

Alternative 1: DEQ verifies credits prior to sale (voluntary or mandatory). *Arguments in favor — 1) Provides more certainty to a buyer of a credit. 2) Regulated parties will not purchase unverified credits.*

Alternative 2: DEQ provides more information during the year to increase the transparency of the credit market. *Arguments in favor — 1) A more transparent reporting system could lead to a better functioning, more responsive market, and regulated and opt-in parties would have information on current low carbon fuel credit prices and parties with available credits for sale.*

Alternative 3: DEQ facilitates credit sales. *Arguments in favor — 1) This approach would provide more transparency for the credit market.*

Alternative 4: Same methodology as CA. *Arguments in favor — 1) easier for regulated and opt-in parties to report the same way in both CA and OR.*

**Rationale for DEQ Proposal**

DEQ’s proposal for buying and selling credits ensures that credit sellers are held responsible for invalid credits, which should provide certainty for credit purchasers. Verification of credits prior to sale could be time consuming and hinder the sale of credits.

This structure for a credit market has the least amount of administrative burden on both regulated and opt-in parties, and DEQ compared to other options that the advisory committee discussed. This is the least complex of the options, and the easiest to implement. There would be fewer barriers to buying and selling credits, and therefore this option could decrease compliance cost. Under this
option, there is less transparency in the credit market than other options considered by the advisory committee. The lack of this transparency could impede credit transactions because the regulated and opt-in parties would have less information on current low carbon fuel credit prices and parties with available credits for sale.

*Advisory committee input on this issue can be found in Appendix A.*

## 9. Fuel Supply Deferrals

House Bill 2186 directs the Environmental Quality Commission to adopt standards for the issuance of deferrals from the low carbon fuel standards for inadequate low carbon fuel supplies. DEQ staff envisions two types of fuel supply deferrals under the low carbon fuel standards:

1. **Temporary fuel supply deferrals.** Expedited deferrals for disruptions in the existing low carbon fuel supply attributed to immediate production or transportation problems. These deferrals are for addressing short-term disruptions in fuel supply that would not warrant an adjustment to the overall low carbon fuel standards compliance schedule;

2. **Forecasted fuel supply deferrals.** Deferrals to account for anticipated future shortages in the volumes of low carbon fuels needed to meet the low carbon fuel standard. These deferrals are for addressing forecasted fuel shortages, and in some instances, could warrant re-setting the overall low carbon fuel standards compliance curve and/or changing the program horizon year from 2022 to some later date.

House Bill 2186 also contains deferrals for fuel price. Please see Section 10: Consumer Cost Safety Net on page 101 for information on fuel price deferrals.

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**HB 2186**

**SECTION 6**

(2)(a) The Environmental Quality Commission may adopt by rule low carbon fuel standards for gasoline, diesel and fuels used as substitutes for gasoline or diesel. (b) The commission may adopt the following related to the standards, including but not limited to:

…. (D) Standards for the issuance of deferrals, established with adequate lead time, as necessary to ensure adequate fuel supplies;

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While fuel supply deferrals are unlikely to be necessary in the early years of the low carbon fuel standards due to the large volumes of fuels required by the federal RFS2, fuel supply deferrals could become an issue in later years when volumes beyond RFS2 or use of other low carbon fuels are required for compliance. In addition, if federal RFS2 fuel volume requirements are reduced, fuel supply deferrals might become necessary. Fuel supply deferrals are not intended to be issued for supply shortages due to increased price, when production facilities are taken offline for regularly scheduled maintenance or when sufficient credits can be purchased to comply with the low carbon fuel standards. Fuel supply deferrals are meant for extreme situations where a significant disruption
in either the production or transportation of a low carbon fuel, such that an adequate supply of low carbon fuels and/or corresponding credits are not available to meet the low carbon fuel standards. When enacted, deferrals apply to either gasoline or diesel (or their respective substitutes), as opposed to a particular regulated party.

DEQ staff propose to evaluate the magnitude, duration and cause of inadequate supplies of low carbon fuel to determine if a deferral from the low carbon fuel standards is warranted. If warranted, DEQ staff would select the type and duration of deferral and implement any necessary compliance obligation adjustments. The process for fuel supply deferrals and the compliance obligation adjustments are discussed for both temporary and forecasted fuel supply deferrals in the following sections.

A. Process for issuing Fuel Supply Deferrals

DEQ staff propose two similar but distinct processes for evaluating and responding to temporary and forecasted low carbon fuel supply shortages.

- For temporary deferrals (short-term supply disruptions) and forecasted deferrals that do not change the low carbon fuel standard in future years, DEQ would use an administrative process in the low carbon fuel standards rules to allow for expedited issuance of a deferral.
- For forecasted deferrals that do involve changing the low carbon fuel standards in future years, DEQ proposes either an administrative process or a temporary rulemaking process to change the low carbon fuel standard immediately, followed by a traditional rulemaking process to permanently alter the low carbon fuel standards in future years.

Upon issuing a deferral from the low carbon fuel standards, DEQ will specify the type of fuel to which the deferral applies. In other words, DEQ would specify whether the deferral applied to gasoline and gasoline substitutes or diesel and diesel substitutes. DEQ would also specify the deferral period start date and end date, or would specify the start date and leave the deferral period open. Under all options, credits would continue to accrue during a deferral period for all fuel types that have a carbon intensity less than the current low carbon fuel standard.

i. Process for Determining whether to issue a Temporary Fuel Supply Deferral

House Bill 2186 allows for deferrals of the low carbon fuel standards to ensure an adequate fuel supply in case of unanticipated disruptions in existing fuel production or infrastructure. For example, unusual events such as the unanticipated closure of a large fuel plant or a natural disaster that disrupts fuel distribution could cause Oregon to experience a shortage of low carbon fuels. If the disruption were large enough, addressing the disruption would likely involve deferring or temporarily suspending the compliance obligation during the disruption period because compliance is predicated on the availability of an adequate supply of low carbon fuels.

DEQ proposes to establish a significance threshold to determine if and what type of temporary deferral from the low carbon fuel standards should be issued. The significance threshold would allow DEQ to quickly identify disruptions in the supply of low carbon fuel that warrant a
deferral from the low carbon fuel standards, and prompt an investigation into the cause of the disruption to determine the appropriate type and duration of deferral to issue.

To initiate the process, upon learning of a fuel supply disruption, DEQ would obtain the best information available on the type of fuel disrupted, the carbon intensity of the disrupted fuel, and the anticipated duration of the fuel supply disruption. From this information, DEQ can calculate the estimated number of credits that will be disrupted. This would “weight” the disruption and gives a measure of the significance of the disruption. For example, disrupting a certain volume of very low carbon intensity fuel would have more of an impact on the credits lost than disrupting a fuel with higher carbon intensity.

**Significance Threshold:** If the number of credits lost due to a fuel supply disruption exceeds five percent (5 percent) of the total aggregate number of credits used to meet compliance obligations under the low carbon fuel standards in the previous calendar year, DEQ and Oregon Department of Energy may begin an investigation to evaluate the risk to and compliance with the low carbon fuel standards. Fuel shortages at or above this threshold would be evaluated using the criteria below to determine if a deferral is warranted, and if so, the appropriate deferral type:

- The volume and carbon intensity of low carbon fuel disrupted and the expected duration of the shortage.
- The availability of low carbon fuels from other sources, and the carbon intensity of that fuel which could be used to show compliance in lieu of a deferral.
- The availability of banked low carbon fuel credits that could be used to show compliance in lieu of a deferral.
- Range and type of impact: Broad impact on a number of regulated parties or narrow impact on just a few regulated parties.
- Magnitude of impact on individual and collective regulated parties.

If the disruption ends, or if an adequate volume of other low carbon fuels become available, DEQ will end the deferral period.

**Alternatives considered**

Alternative 1: The advisory committee discussed credit disruptions in the range of 5-25 percent.

Alternative 2: A threshold, below which DEQ would not be able to issue deferrals.


**Rationale for DEQ Proposal**

The authorizing statute requires deferrals for adequate fuel supply.

5 percent of credits lost is a conservative early warning threshold because regulated parties will be able to carry over 10 percent of deficits as a “small deficit” (see page 88). DEQ determined
that a threshold below which DEQ would not be able to issue deferrals was arbitrary and unnecessary.

A conservative warning level is important for two reasons: 1) fuel supply deferrals protect regulated parties from fuel supply shortages beyond their control and 2) even a 5 percent credit shortage can seriously impact some regulated parties.

Although the threshold for investigation needs to be low, DEQ needs to be careful not to issue unnecessary deferrals. Excessive use of deferrals could penalize early actors, act as a disincentive to investments in low carbon fuels, and may inhibit or prolong the growth of alternative fuels production and use.

### ii. Process for Determining Whether or Not to Issue a Forecastsed Fuel Supply Deferral

House Bill 2186 allows for deferrals from the low carbon fuel standards to ensure an adequate fuel supply in the event that anticipated production or use volumes of low carbon fuels do not materialize as planned. Forecasted fuel supply shortages could significantly affect the ability of regulated parties to comply with the low carbon fuel standards, and may warrant either a deferral of the low carbon fuel standards for up to a year, or a review and/or revision of the low carbon fuel standards compliance schedule. To determine the need for a forecasted fuel supply deferral, DEQ would assess whether sufficient volumes of low carbon fuel (including electricity, natural gas, biofuels, synthetic fuels etc.) can be reasonably expected to meet the following year’s low carbon fuel standards. This would be done by comparing the low carbon fuel standards for the following year (as indicated on the low carbon fuel standards compliance schedule) with forecasted volumes and carbon intensities of anticipated future supplies of low carbon fuels.

DEQ, in consultation with the Oregon Department of Energy, will collect and evaluate the following information to annually project low carbon fuel volumes and respective carbon intensities for the following year:

- Trends in alternative fuel transportation use, such as use of electricity, CNG, LNG, biogas, etc. based on low carbon fuel standards reporting or any other data;
- The status of existing and planned alternative fuel production facilities such as biofuels plants, synthetic fuel plants, and biogas facilities;
- Planned projects such as electric vehicle charging or CNG fueling station installations;
- RFS2 volumes for cellulosic, advanced biofuels, and biomass-based diesel;
- Updates to the carbon intensities of fuels (if applicable);
- Banked credits; and
- Projected total fuel consumption volumes, including gasoline and diesel.

DEQ proposes to use the following significance threshold to determine when to initiate a deferral to address shortages in the future availability of low carbon fuels in Oregon:

**Significance Threshold - Forecasted Deferrals:**
DEQ will use fuel volume projections to calculate the carbon intensity of Oregon’s fuel supply for the following year, and compare total credits available with credits needed for that year. If the forecasted credits available are 5 percent less than the credits needed for that year, DEQ and ODOE may begin an investigation to evaluate whether or not sufficient volumes and carbon intensities of low carbon fuels will be available in the future to assure compliance with the low carbon fuel standards.

DEQ might also forecast more than one year out, particularly for years where the reduction is larger.

**Alternatives considered**

Alternative 1: If the projected volume and carbon intensity of transportation fuel in Oregon for a future year exceeds the low carbon fuel standards for that future year by 0.1 percent or more, DEQ and ODOE may begin an investigation to evaluate whether or not sufficient volumes and carbon intensities of low carbon fuels will be available in the future to assure compliance with the low carbon fuel standards. *Arguments in favor — 1)* A 0.1 percent significance threshold, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5 percent confidence interval.

Alternative 2: Account for the 10 percent small deficit carryover needs to be accounted for in this calculation. *Arguments in favor — 1)* Because regulated parties will be able to carry over 10 percent of deficits, a 5 percent significance threshold is too low.

**Rationale for DEQ Proposal**

Forecasting available supplies of low carbon fuels can assist DEQ to evaluate the feasibility of the low carbon fuel standards in the following year. It is important to have a conservative investigation level to protect regulated parties from fuel supply shortages beyond their control. If the difference between the forecasted and required credits is greater than the significance threshold, that does not guarantee a deferral, but will initiate an investigation to determine if deferrals are needed.

The 10 percent small deficit carryover is intended to provide flexibility for regulated parties and should not be included in the calculation of the significance threshold.

**B. Compliance Adjustment Options for Fuel Supply Deferrals**

If, through the course of investigation, DEQ makes a determination that regulated parties have sufficient means of meeting the standards at their disposal, (i.e. availability of alternate sources of low carbon fuels or sufficient credits to meet the standards in lieu of a deferral, the magnitude of disruption or fuel shortage does not impede regulated parties’ ability to comply with the standards, etc.), DEQ would not issue a fuel supply deferral or initiate a temporary rulemaking to adjust the low carbon fuel standards for future years.

In the event that DEQ determines that a deferral from the low carbon fuel standards is warranted, DEQ must address the compliance obligations of regulated parties, taking into account the effect of the disruption or fuel shortage as it relates to the low carbon fuel standards compliance schedule. DEQ staff propose to administratively issue a fuel supply deferral if one is needed.
i. Compliance Obligation Adjustments for Temporary Fuel Supply Deferral

DEQ proposes the following two types of temporary fuel supply deferrals to administratively address compliance obligations of regulated parties under a temporary deferral from Oregon’s low carbon fuel standards:

**Temporary Fuel Supply Deferral Type 1:** This option is suitable for temporary supply disruptions where the magnitude of the disruption is not expected to negatively impact the overall greenhouse gas reduction goals of the low carbon fuel standards.

Deficits generated during a temporary deferral period are allowed to be carried over and paid back within one to three years from the year in which the deferral period occurred, dependent on the extent and duration of disruption in low carbon fuel supplies. Under this option, regulated parties would be required to make up any deficit between the standard and the actual average carbon intensity of the low carbon fuels they sold in a given year.

**Temporary Fuel Supply Deferral Type 2:** This type of deferral better addresses larger fuel supply disruptions than a Type 1 Temporary deferral does.

During the deferral period, no deficits would accrue for the fuel type for which the deferral has been issued. Volumes of conventional fuel (and any fuel with a carbon intensity greater than the standard sold during a deferral period) would not be included in the compliance calculation for the duration of the deferral period, nor would such volumes accrue deficits during the deferral period. This type of deferral would result in less greenhouse gas emissions reductions achieved.

**Alternatives considered**

- Alternative 1: DEQ also considered “long-term deferrals”, but has abandoned this idea since extended fuel supply shortages are better covered under “forecasted fuel supply deferrals.”

- Alternative 2: DEQ considered setting an “alternate standard” but has abandoned this idea as overly complex.

- Alternative 3: Fuel price should be considered in fuel supply deferrals.
Rationale for DEQ Proposal

Because the magnitude, effect, and consequences of fuel supply shortages could vary, it is important to have a variety of options available to allow DEQ to address different situations.

ii. Compliance Obligation Adjustments for *Forecasted Fuel Supply Deferral*

If DEQ determines that the magnitude of the low carbon fuel supply disruption negatively impacts the ability of regulated parties to meet the standard, DEQ will select one of two compliance adjustment options below:

**Forecasted Fuel Supply Deferral Type 1:** Defer the standard for up to a year;

**Forecasted Fuel Supply Deferral Type 2:** Revise the low carbon fuel standard for subsequent years by implementing one of the following:

- Revise the LCFS; or
- Revise the LCFS and extend the program beyond the horizon year (2022).

DEQ would use a Type 1 Forecasted Deferral if there was a forecasted disruption that would last a year or less, and then after that, low carbon fuel is expected to be available in sufficient quantities. DEQ would use a Type 2 Forecasted Deferral if low carbon fuel is expected to be insufficient to meet the low carbon fuel standard for more than one year.

DEQ proposes to address the **Type 1 Forecasted Fuel Supply Deferral** administratively, because a deferral for up to one year will not change the 2022 low carbon fuel standard. However, should DEQ determine that a **Type 2 Forecasted Fuel Supply Deferral** is needed to adjust the compliance obligation of regulated parties under the low carbon fuel standards, DEQ proposes to use a temporary rulemaking process to revise the standard for that year expeditiously, followed by a traditional rulemaking process to permanently revise the overall compliance schedule and obligations of regulated parties under the low carbon fuel standards.
Figure 9: Temporary Fuel Supply Deferrals

Figure 10: Forecasted Fuel Supply Deferrals
Alternatives considered

Alternative 1: Include another alternative where reductions could be made up in future years. Arguments in favor — 1) Whenever possible, DEQ should make up for reductions lost in deferrals.

Rationale for DEQ Proposal

5 percent of credits lost is a conservative early warning threshold because regulated parties will be able to carry over 10 percent of deficits as a “small deficit” (see page 88). DEQ determined that a significance threshold (below which DEQ would not be able to initiate a deferral) was not desirable because DEQ needs the flexibility to respond to a variety of situations.

A conservative warning level is important for two reasons: 1) fuel supply deferrals protect regulated parties from fuel supply shortages beyond their control and 2) even a 5 percent credit shortage can seriously impact some regulated parties.

Although the threshold for investigation needs to be low, DEQ needs to be careful not to issue unnecessary deferrals. Excessive use of deferrals could penalize early actors, act as a disincentive to investments in low carbon fuels, and may inhibit or prolong the growth of alternative fuels production and use. Forecasting available supplies of low carbon fuels can assist DEQ to evaluate the feasibility of the low carbon fuel standards in the following year. It is important to have a conservative warning level to protect regulated parties from fuel supply shortages beyond their control.

Because the magnitude, effect, and consequences of fuel supply shortages could vary, it is important to have options available to allow DEQ to address different situations. Allowing an administrative fix that does not have lasting change on the compliance curve or horizon year is an important option.

Advisory committee input on this issue can be found in Appendix A.

10. Consumer Cost Safety Net

The consumer cost safety net is intended to protect fuel consumers in the event that low carbon fuel standards cause an increase in gasoline or diesel prices, and give the Environmental Quality

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SECTION 6 (2) (d) The commission shall provide exemptions and deferrals as necessary to mitigate the costs of complying with the low carbon fuel standards upon a finding by the commission that the 12-month rolling weighted average price of gasoline or diesel in Oregon is not competitive with the 12-month rolling weighted average price in the PADD 5 region.

(1) As used in this section:
Commission tools to mitigate a price increase due to the low carbon fuel standards. This consumer cost safety net is specific to the price of gasoline and diesel. House Bill 2186 has other exemptions for other purposes, such as to ensure an adequate fuel supply (See Section 11: Fuel Supply Deferrals on page 93).

**Proposed Consumer Cost Safety Net:** DEQ proposes that when the 12-month rolling weighted average price of gasoline or diesel in Oregon is more than 5 percent above the 12-month rolling weighted average price of gasoline or diesel in the statutory Iv PADD-5, this can trigger an investigation leading to an Environmental Quality Commission determination of whether or not exemptions and deferrals are necessary. This issue can be brought before the Environmental Quality Commission in the following way:

An entity outside of DEQ can track U.S. Energy Information Administration v information, or more current price and volume information, and if the 12-month rolling average price of gasoline or diesel in Oregon is greater than 5 percent above the statutory PADD-5 average, then the entity can provide data to DEQ and request an investigation.

In addition, DEQ proposes to track the 12-month rolling average price of gasoline in Oregon and the statutory PADD-5 on a monthly basis, based on published Energy Information Administration data. DEQ will track the 12-month rolling weighted average price of diesel in Oregon and in the actual PADD-5 on a monthly basis, based on published Energy Information Administration data. There is a 3-4 month lag in publication of Energy Information Administration data. If prices in Oregon reach the trigger (i.e. greater than 5 percent over the prices in the statutory PADD-5), then DEQ will investigate whether the cause of the non-competitive price is due to the low carbon fuel standards. DEQ will use the criteria listed below to make this determination, and bring a recommendation to the Environmental Quality Commission.

The Environmental Quality Commission will consider the extent to which the low carbon fuel standards caused the non-competitive Oregon gasoline or diesel price, or whether there were other causal factors unrelated to the low carbon fuel standards. In order to trigger a consumer cost safety net exemption or deferral, the Environmental Quality Commission would have to find that the cause of the non-competitive Oregon gasoline or diesel price is attributable to the low carbon fuel standards, and not some other factor, and that action is necessary to mitigate the non-competitive price.

Other causal factors that could affect the price of gasoline or diesel include, but are not limited to:

- Faulty or incomplete fuel volume and price data;
- Natural or manmade disasters affecting the fuel supply to Oregon, but not one of the other states (Washington, Arizona, or Nevada);

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iv Please note that the actual PADD-5 is different from the HB 2186-defined statutory PADD-5. For the purposes of Oregon low carbon fuel standards, the legislature has defined PADD-5 as only including the states of Oregon, Washington, Nevada and Arizona.

v The U.S. Energy Information Administration collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. Information can be found at www.eia.doe.gov/.
• Crude oil prices in Alaska and sources of Oregon’s crude vs. crude prices for fuel supplied to Arizona and Nevada;
• Seasonal demands or unusual demands (for example, the Olympic games);
• A change in environmental regulations that affects Oregon, but not Washington, Arizona or Nevada;
• Arizona discontinues its use of reformulated gasoline;
• An increase in population or demand for fuel; and
• A decrease in retail outlets for fuel.

The Environmental Quality Commission would also need to make a finding that exemptions and deferrals are necessary to mitigate the non-competitive price. The commission would need to consider the current and future supply and availability of low carbon fuels, as well as the phase-in schedule of the rule, in order to evaluate to what extent a deferral or exemption would help make the price of Oregon gasoline or diesel more competitive.

In making a recommendation to the commission, DEQ may ask petitioners to submit data related to the factors listed above so that DEQ is able to assess the cause of a price increase.

DEQ will recommend one of the following for either gasoline and gasoline substitutes, or diesel and diesel substitutes for consideration by the commission:

1. **No exemptions or deferrals**, if the low carbon fuel standards are not found to be the cause of the non-competitive price; or
2. **Allow regulated parties** to carry over large deficits and pay them back over the following one to three years; or
3. **Exempt** either gasoline and gasoline substitutes or diesel and any diesel substitutes with a carbon intensity equal to or higher than diesel from the low carbon fuel standard for up to one year; or
4. **Exempt a percentage** of either gasoline and gasoline substitutes or diesel and any diesel substitutes fuels from the low carbon fuel standard for up to one year; or
5. **Defer a low carbon fuel standard** for up to one year.

Credits still accrue during a consumer cost safety net exemption or deferral period.

If the Environmental Quality Commission makes a finding that a non-competitive price is not caused by the low carbon fuel standards, the commission may reconsider issuing an exemption or a deferral when one of the causal factors listed above changes.

If the commission makes a finding that a non-competitive price is caused by the low carbon fuel standard and issues an exemption or a deferral, the commission can remove the exemption or deferral when one of the causal factors listed above changes such that the low carbon fuel standard is no longer causing a non-competitive price.

**Rationale for DEQ Proposal**

**Proposed definition of “non-competitive” for gasoline and diesel.** The definition of non-competitive is important because it will determine when an investigation into a price difference is
triggered. The trigger needs to be high enough to account for normal fluctuation in gasoline and diesel prices, and so that an investigation would not be triggered unnecessarily. It also needs to be low enough so that it would capture any impacts from the low carbon fuel standards early on.

DEQ proposes to conduct an investigation into whether Oregon’s price of gasoline or diesel is “non-competitive” when Oregon’s 12-month rolling weighted average price of gasoline is 5 percent greater than the 12-month rolling weighted average price of gasoline or diesel in the statutory PADD-5 (Washington, Arizona, Nevada and Oregon).

Gasoline Prices in Oregon and the statutory PADD-5: For almost a decade, Oregon’s gasoline prices have varied within a very narrow range of the statutory PADD-5 prices. On page 104, Figure 11 graphs the 12-month rolling weighted average retail price of gasoline in Oregon and in the statutory PADD-5. As you can see in Figure 12 (page 104), Oregon’s average gasoline prices have generally been within 3 percent of the statutory PADD-5 prices, but have had a recent jump to 4 percent in 2007, and have since remained higher than previous years. In Figure 12, positive percent numbers indicate that the average Oregon price of gasoline is higher than the PADD-5 average price. Negative percent numbers indicate that the average Oregon price of gasoline is lower than the PADD-5 average price.

**Figure 11: 12-Month Rolling Weighted Average Retail Gasoline Prices:**
Oregon and Statutory PADD-5: April 2000 to July 2009

![Figure 11](image_url)

Data from Energy Information Administration websites:
Price: [http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_a_EPM0_PTA_cpgal_m.htm](http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_a_EPM0_PTA_cpgal_m.htm)
Volume: [http://tonto.eia.doe.gov/dnav/pet/PET_CONS_PRIM_DCUSOR_M.htm](http://tonto.eia.doe.gov/dnav/pet/PET_CONS_PRIM_DCUSOR_M.htm)
DEQ has looked at the variation in Oregon’s price of diesel, compared to the actual PADD-5. Figure 13 on page 106 plots Oregon and PADD-5’s diesel prices. Figure 14 on page 107 shows the percent difference between Oregon’s and PADD-5 diesel prices for the past 10 years. In Figure 14 on page 107, positive percent numbers indicate that the avg. Oregon price of diesel is higher than the PADD-5 average price. Negative percent numbers indicate that the average Oregon price of diesel is lower than the PADD-5 average price.
Figure 13: 12-Month Rolling Weighted Average Retail No. 2 Diesel Prices: Oregon and PADD-5. April 2000 to July 2009

Data from Energy Information Administration websites:
Price weighted by volume: http://tonto.eia.doe.gov/dnav/pet/pet_pri_dist_dcu_R50_m.htm
Figure 14: Percent Difference Between the 12-month Weighted Average Diesel Price in PADD-5 and OR. April 2000 to June 2009

Data from Energy Information Administration websites:
http://tonto.eia.doe.gov/dnav/pet/pet_pri_dist_dcu_R50_m.htm

Alternatives considered

Alternative 1: Using Oil Price Information Service or other data. *Arguments in favor — 1) No time lag.*

Alternative 2: Using a 1 percent–4.9 percent a non-competitive price bracket. *Arguments in favor — 1) We need to protect consumers from any price increases due to the low carbon fuel standards.*

Alternative 3: Using 10 percent as a non-competitive price threshold. *Arguments in favor — 1) Such a low threshold for price variability does not encourage substitution. A higher range of allowed price impact would encourage substitution at a higher rate, potentially resulting in stabilization at a lower price later on. A 10 percent difference might be more appropriate for a trigger than five percent. 2) It is important not to mask the effect of the low carbon fuel standards.*

Alternative 4: Issue exemptions and deferrals administratively, instead of waiting for the Environmental Quality Commission to make a finding. *Arguments in favor — 1) Time will be critical in addressing any non-competitive price.*

Alternative 5: No price deferrals included. *Arguments in favor — 1) Having provisions for fuel supply deferrals creates uncertainty and risk for low carbon fuel providers and favors regulated parties.*
Rationale for DEQ Proposal

The U.S. Energy Information Administration has the most accurate volume-weighted price data. U.S. Energy Information Administration data does not contain taxes, which some committee members felt was important. DEQ will accept other data if U.S. Energy Information Administration data is not available.

The authorizing statute requires the inclusion of deferrals when the low carbon fuel standards cause a non-competitive 12-month rolling average price of gasoline or diesel in Oregon as compared to other states. With regard to the non-competitive price, the trigger needs to be high enough to account for normal fluctuation in gasoline and diesel price, so that an investigation would not be triggered unnecessarily. It also needs to be low enough so that it would capture any impacts from the low carbon fuel standards early on. Because Oregon’s 12-month rolling weighted average price of gasoline has not gone over 5 percent above the 12-month rolling weighted average price of gasoline in the statutory PADD-5 during the past 10 years, 5 percent is deemed high enough to account for normal fluctuation in gasoline prices so that an investigation would not be triggered unnecessarily, yet low enough so that it would capture any impacts from a low carbon fuel standards.

Because the statute requires the Environmental Quality Commission to make a finding, it is unlikely that authority will be delegated to DEQ. In addition, because the exemptions and deferrals are for a 12-month rolling average, the problem will be building for several months, and DEQ can track it and be prepared.

**Advisory committee input on this issue can be found in Appendix A.**

11. Implementation Issues

A. Use of Biodiesel and Renewable Diesel

Throughout the advisory committee process, there were several discussions about the use of biodiesel blends in various types of engines. *Appendix K: Review of Biodiesel and Renewable Diesel Use Considerations* provides a review of biodiesel and renewable diesel use considerations.

**Advisory committee input on this issue can be found in Appendix A.**

B. Storage and Distribution of Low Carbon Fuels

There are several important issues related to the storage and distribution of increased low carbon fuels use. Depending on the fuels used in the future, additional infrastructure will be needed to support low carbon fuel use. Terminals might require additional storage tanks for biofuels, additional truck unloading, and blending and ancillary equipment. Additional tanker trucks might be needed to distribute biofuels or bring additional biofuels to the terminal. Additional storage tanks and fueling or charging stations might be needed at gas stations. For example, additional CNG use in the future would require additional fueling stations, and additional E85 use could involve not only additional infrastructure at the gas station, but also infrastructure changes at the terminal to accommodate increased volumes of ethanol. Each of the compliance scenarios
described beginning on page 149 outlines additional infrastructure that would be needed to produce, store and distribute the low carbon fuels included in that scenario. This additional infrastructure is described in a memo for DEQ’s contractor, TIAx, and is included as Appendix C: Infrastructure Cost Assumptions Memorandum. Additional infrastructure costs due to the low carbon fuel standards are included in the economic analysis.

Advisory committee input on this issue can be found in Appendix A.

C. Recordkeeping and Reporting

Documentation is a very important element to implementing the low carbon fuel standards. It will be necessary to be able to track the carbon intensity of specific fuels in order to determine whether a regulated facility has met their compliance obligation or not. A combination of recordkeeping and reporting requirements will cover the documentation needs of this regulatory program while attempting to minimize the amount of oversight needed by DEQ.

For alternative fuel volumes such as CNG, LNG, hydrogen, or electricity, if there is a sub-meter on the fuel dispenser, the opt-in or regulated party must use that for fuel volume reporting. If there is no sub-meter on the fuel dispensing equipment, the regulated or opt-in party may report the amount of fuel dispensed using any other method that is substantially similar to or better than the use of sub-meters (as determined by DEQ). DEQ will consider requiring sub-metering in the 2014 and 2016 reviews.

**Recordkeeping** – to be maintained by the regulated party at its facility

Each delivery:

- Volume of each fuel provided,
- Volume of fuel provided to each exempt user, and
- Carbon intensity of each fuel provided that is not exempt.

Credits sold or bought:

- Seller;
- Buyer;
- Price;
- Number of credits; and
- Date of transaction.

Where the compliance obligation is transferred or retained by written contract:

- Copy of the contract.

Quarterly carbon intensity calculation:

- The volume of each fuel provided;
- The calculated carbon intensity of each fuel provided;
- Emission credits that are acquired, sold, or banked for future use; and
- The volume of fuel that is exempt from the low carbon fuel standard.

**Reporting** – to be submitted to the agency

Initial physical pathway report:

- The physical routes (truck, rail, pipeline, etc.) by which a fuel is transported or distributed from its point of production through any intermediaries to the fuel blender, producer, importer or provider;
- Carbon intensity of the pathway using OR-GREET;
- Evidence of fuel entering a physical pathway;
- Volume capacity of fuel produced via the pathway; and
- Evidence of an equal amount of fuel being removed from a fuel pathway (showing the pathway is actually being used by the company).

Revision report (as needed):

- Revisions to physical pathways when conditions change.

Annual report:

- Total credits carried over from the previous year;
- Total deficits carried over from the previous year;
- Total credits generated in the current year;
- Total deficits generated in the current year;
- Total credits acquired or sold for each credit transaction for the current year;
- Total credits to be carried over to the next year; and
- Total deficits to be carried over to the next year.

Regulated or opt-in parties submitting reports may request information be exempt from disclosure pursuant to ORS 192.501.

As part of its program, California Air Resources Board is developing its own web-based reporting tool. It will be capable of supporting their requirement for quarterly carbon intensity calculations and tracking of credit trading. California Air Resources Board has agreed to give Oregon a copy of this tool and DEQ envisions that this might be the primary mechanism for reporting. If this tool is not available or appropriate for Oregon, then DEQ would consider either developing its own on-line reporting tool or developing reports to be submitted manually.
Alternatives considered

Alternative 1: Quarterly reporting. Arguments in favor — 1) Quarterly reporting would help regulated parties know their status with the low carbon fuel standards and whether they needed more credits to meet the standards.

Alternative 2: Quarterly compliance with low carbon fuel standards. Arguments in favor — 1) Quarterly compliance for the low carbon fuel standards would ensure credits are sold throughout the year, instead of mostly toward the end of the year.

Align low carbon fuel standards reporting with one of the following existing programs:

Alternative 3: Oregon Department of Transportation’s fuel tax reporting.

Alternative 4: DEQ’s greenhouse gas reporting rule Phase II.

Alternative 5: DEQ’s air quality permitting program for industrial emissions, which includes DEQ’s reporting requirements for bulk gasoline plants and gasoline dispensing facilities.

Alternative 6: California reporting 1) consistency with California and ease for regulated parties in both states 2) could use their web tool 3)

Arguments in favor of alternatives 3-6 — 1) Streamlining reporting requirements.

Rationale for DEQ Proposal

It is necessary to track the carbon intensity of specific fuels in order to determine whether a regulated facility has met their compliance obligation.

DEQ originally proposed quarterly reporting. DEQ’s proposal has been modified to include a combination of recordkeeping and reporting requirements to provide the documentation needs of this regulatory program while attempting to minimize the amount of oversight needed by DEQ. In addition, keeping reporting simple will encourage opt-in parties to participate. See credit selling and buying section on page 91 for discussion of transparency of market.

The first year of the low carbon fuel standards requires reporting only; compliance with carbon intensity standards begins with the second year of the program. This approach provides a transitional period in which affected parties can become familiar with the reporting systems.

Consistency with ODOT fuels tax and DEQ greenhouse gas reporting rules was an important consideration in choosing regulated parties. DEQ’s research and discussion with stakeholders showed that the regulated party for the LCFS needs to be different from the entities regulated under ODOT fuels tax, DEQ greenhouse gas reporting rules, or DEQ permits. For a discussion, please see section on regulated parties for gasoline, diesel and biofuels on page 57.

Several committee members expressed their support for using an adapted version of California’s web-based reporting tool.

Advisory committee input on this issue can be found in Appendix A.
D. Enforcement

DEQ’s enforcement rules are located in Oregon Administrative Rules Division 12. Very typically, a new program like the low carbon fuel standards will propose new enforcement language while drafting the program rules. However, DEQ is not proposing any changes to Division 12 at this time. Existing guidance on enforcement of general air quality violations will be used if violations of the low carbon fuel standards occur prior to Division 12 being updated. The next scheduled update of Division 12 is planned for 2011 and DEQ will propose new enforcement language to incorporate specific violations at that time.

Several types of violations could occur as the low carbon fuel standards get implemented, including:

- Failure to submit a report
- Failure to maintain records
  - Failing to perform monitoring, require by rule, that results in failure to show compliance
  - Failing to perform monitoring, required by rule, where missing data can be reconstructed to show compliance with standards
- Falsification of information on a report
- Failure to apply for a new fuel pathway
- Failure to comply with the low carbon fuel standard

The current version of Division 12 can be found at: [http://arcweb.sos.state.or.us/rules/OARs_300/OAR_340/340_012.html](http://arcweb.sos.state.or.us/rules/OARs_300/OAR_340/340_012.html).

Alternatives considered

Alternative 1: Develop draft rules and guidance for Division 12 at the same time as the development of the low carbon fuel standards program. Arguments in favor — Since not all violations listed above are considered in existing enforcement rules, there can be unintended inconsistencies in how the general enforcement guidance would apply to specific violations.

Rationale for DEQ Proposal

As proposed, 2012 is a reporting-only year for the low carbon fuel standards. Any regulated or opt-in party failing to submit a report in this year will addressed through additional technical assistance rather than enforcement. 2013 will be the first compliance year, making the first annual report due in Spring 2014. By then, DEQ will update the Division 12 rule to incorporate specific language.

Advisory committee input on this issue can be found in Appendix A.
E. Standards, Specifications, Testing Requirements to Ensure Quality of Fuels

The Oregon Department of Agriculture Measurement Standards Division is responsible for testing fuel quality in Oregon. Information on motor fuel quality in Oregon can be found on the Oregon Department of Agriculture website: [http://oregon.gov/ODA/MSD/motor_fuel_info_center.shtml](http://oregon.gov/ODA/MSD/motor_fuel_info_center.shtml).

Fuel standards and specifications are found in Oregon Administrative Rules Motor Fuel Quality Regulations OAR 603-027-0410 through 603-027-0490. These rules list the standards and specifications that Oregon transportation fuel must meet.

The rules have standards for gasoline, diesel, biodiesel and ethanol, including E85 (85 percent ethanol, 15 percent gasoline).

Renewable diesel (“Other Renewable Diesel”) is defined in the Oregon Administrative Rules, but in order to be sold in Oregon, renewable diesel needs to have an established ASTM International standard, must be approved by the EPA, and must meet specifications of the National Conference on Weights and Measures, designated “100 percent Biomass-Based Diesel.”

There are standards for natural gas in Oregon Administrative Rules 860-023-0025. However, there are no specific standards for compressed or liquefied natural gas from fossil or biogas sources.

There are no Oregon standards or specifications for hydrogen or hydrogen blends used as transportation fuels.

F. Safety of Alternative Fuels

House Bill 2186 directs the Environmental Quality Commission to consider the safety of the low carbon fuel standards. The purpose of this section is to characterize any significant safety differences between conventional and alternative fuels. All transportation fuel is flammable to some degree; handling specifications and precautions are required for each fuel. This section will not describe these requirements in detail, but will merely highlight significant differences in safety resulting from switching from conventional fuels (gasoline and diesel) to alternative fuels. This section will describe any major safety differences DEQ found when researching the safety of alternative fuels and vehicles.

**Ethanol**

**Vehicles:** Gasoline vehicles, which can use a blend containing 10 percent ethanol, are fully commercialized, as are flex fuel vehicles that use gasoline, 85 percent ethanol, or a mix of the two. The safety concerns for flex fuel vehicles are the same as for gasoline vehicles.

**Fueling:** In 2006, Underwriters Laboratories (UL), the organization that develops safety standards for fuel dispensers, initiated a research program for E85 dispensers and found no significant problems or safety issues. The U.S. Department of Energy’s web site provides examples of interim state guidance documents and other information on E85 dispensers for local authorities. (U.S. EPA website 2010, "E85 Fuel Dispensers", [6])

**Fuel Handling:** The safety standards for handling E85 are the same as those for gasoline. (U.S. DOE AFDC website 2010, "E85 Safety Concerns"). Fire safety concerns exist with ethanol, and transporting and blending ethanol fuels could pose a significant fire hazard. Due to ethanol’s
solubility in water, the use of water spray may be inefficient when fighting fire involving ethanol-gasoline blends. Ethanol-blended fuel fires cannot be readily smothered with standard fire fighting foam and as a result, distribution and dispensation of ethanol fuels above E10 could pose a significant fire hazard that requires specialized training and custom-made fire-fighting foams. (Naidenko, Environmental Working Group website, 2010, 8)

**Biodiesel (Fatty Acid Methyl Esters)**

**Vehicles and Fueling:** Biodiesel can be used in unmodified diesel engines with current fueling infrastructure. The safety concerns for vehicles being operated with biodiesel and fueling operations are similar to the safety concerns associated with vehicles that run on conventional petroleum diesel.

**Fuel Handling:** Biodiesel contains no hazardous materials and is generally regarded as non-toxic. (Columbia-Willamette Clean Cities website 2010, "Fuels: Biodiesel", 9) Like any fuel, biodiesel will burn and fire safety precautions must be taken. The flash point of biodiesel is higher than 212°F (100°C). (U.S. DOE NREL website 2010, "Biodiesel Handling and Use Guide", 10) It is considered less flammable than diesel fuel (that has a flash point of 126°F to 204°F) because it doesn't produce explosive vapors. (Columbia-Willamette Clean Cities website 2010, "Fuels: Biodiesel", 11) Biodiesel can be produced in non-commercial settings, and home brewing of biodiesel presents safety concerns that must be considered and addressed. Information on the safety concerns associated with the home brewing of biodiesel is not included in this report, but is available on the internet.

**Hydrogenation-Derived Renewable Diesel, Fischer-Tropsch and Other Synthetic Fuels**

**Vehicles, Fueling and Fuel Handling:** Hydrogenation-derived renewable diesel, Fisher-Tropsch diesel, and other synthetic fuels are expected to substitute directly for or blend in any proportion with petroleum-based diesel, without modification to vehicle engines or fueling infrastructure. (U.S. DOE AFDC website 2010, "What is hydrogenation-derived renewable diesel?", 12) Therefore, safety concerns for vehicles powered by these fuels are expected to be similar to those for conventional diesel powered vehicles and the fuel to be compatible with currently existing fuel distribution systems. (U.S. DOE AFDC website 2010, "Hydrogenation-Derived Renewable Diesel Distribution", 13)

**Electricity**

**Vehicles and Fueling:** Electricity can be used to power electric vehicles directly from the power grid. Electric vehicles must meet the same safety standards required for conventional vehicles sold in the United States. The only exception is neighborhood electric vehicles, which are subject to less-stringent standards because they are typically limited to roadways specified by state and local regulations. All electric vehicles have a high-voltage electric system, which manufacturers have designed with safety features that deactivate the electric system in the event of an accident. In addition, electric vehicles tend to have a lower center of gravity than conventional vehicles, making them less likely to roll over. (U.S. DOE AFDC website 2010, "Electricity", 14)
Fuel Handling: Emergency response for electric drive vehicles is not significantly different from conventional vehicles. (U.S. DOE AFDC website 2010, "Maintenance and Safety of Hybrid, Plug-in Hybrid, and All-Electric Vehicles", 15)

**Compressed Natural Gas (CNG) - Fossil Sources**

Vehicles: Natural gas powered vehicles are designed and built to be safe both in normal operation and in accidents. New natural gas vehicles must meet Federal Motor Vehicle Safety Standards. Natural gas cylinders are required to be inspected every 3 years or 36,000 miles. (Clean Vehicle Education foundation website 2010, "How safe are Natural Gas Vehicles?", 16)

Data collected over time has demonstrated natural gas vehicles to be as safe as, or safer than, conventionally fueled vehicles. (Clean Vehicle Education foundation website 2010, "How safe are Natural Gas Vehicles?", 17)

Fueling: Compression, storage and fueling of natural gas vehicles must meet stringent industry and government safety standards. (Clean Vehicle Education foundation website 2010, "How safe are Natural Gas Vehicles?", 18)

Fuel Handling: Compared to gasoline and diesel, natural gas is non-toxic, and does not pose a risk of ground or water contamination in the event of a fuel release. Natural gas is lighter than air and dissipates rapidly when released. An odorant is added to provide a distinctive and intentionally disagreeable smell that is easy to recognize. The odor is detectable at one-fifth of the gas’ lower flammability limit. Natural gas has a very limited range of flammability – it will not burn in concentrations below about 5 percent or above about 15 percent when mixed with air. Gasoline and diesel burn at much lower concentrations and ignite at lower temperatures. (Clean Vehicle Education foundation website 2010, "How safe are Natural Gas Vehicles?", 19)

**Liquefied Natural Gas (LNG) - Fossil Sources**

Fuel Handling: Issues pertaining to the storage and transportation of LNG have been identified and addressed in the various codes that have been developed by the National Fire Protection Association (NFPA) and under the Uniform Fire Code. There are significant safety differences between handling conventional fuels and LNG. Because it must be kept at such cold temperatures, LNG is stored in double-wall, vacuum-insulated pressure vessels. (U.S. DOE, AFDC website 2010, "CNG and LNG: Alternative Fuels", 20)

Bulk transfer and storage of LNG must address worker protection from the cold liquid, vapor formation prevention and venting, transfer equipment maintenance, as well as extensive leak detection. An explosion of an LNG container is a highly unlikely event that is possible only if the pressure relief equipment or system fails completely or if there is some combination of an unusually high vaporization rate and obstruction of the venting and pressure relief system.

**Biogas (Biomethane)**

Vehicles, Fueling, and Fuel Handling: Benefits of biogas are similar to those of natural gas, and include improved worker safety at landfills and public health. (Columbia-Willamette Clean Cities website 2010, "Fuels: More Alternative Fuels", 21)

Once upgraded to the required level of purity (and compressed or liquefied), biogas can be used as an alternative vehicle fuel in the same forms as conventionally derived natural gas. (U.S. DOE, AFDC website 2010, "What is
Therefore, safety concerns associated with vehicles operated on biogas are expected to be the same as those for vehicles powered by natural gas.

**Hydrogen Fuels**

**Vehicles:** Hydrogen can be used to fuel internal combustion engines and fuel cells, both of which can power low- or zero-emissions vehicles such as fuel cell vehicles. Like all-electric vehicles, fuel cell vehicles use electricity to power motors located near the vehicle's wheels. In contrast to electric vehicles, fuel cell vehicles produce their primary electricity using a fuel cell. Fuel cell vehicles can be fueled with pure hydrogen gas stored directly on the vehicle or extracted from a secondary fuel—such as methanol, ethanol, or natural gas—that carries hydrogen. These secondary fuels must be converted into hydrogen gas onboard the fuel cell vehicle. (U.S. DOE, AFDC website 2010, "What is a fuel cell vehicle?", 23) Fuel cell vehicles and the hydrogen infrastructure to fuel them are in an early stage of development. The U.S. Department of Energy is leading government and industry efforts to make hydrogen-powered vehicles an affordable, environmentally friendly, and safe transportation option. (U.S. DOE, AFDC website 2010, "Fuel Cell Vehicles", 24)

**Fueling:** A safe hydrogen fuel infrastructure still needs to be developed. (Columbia-Willamette Clean Cities website 2010, "Fuels: Hydrogen", 25)

**Fuel Handling:** Hydrogen is a gas at normal temperatures and pressure, which presents greater transportation and storage hurdles compared to liquid fuels. In a closed environment, leaks of any size are a concern, since hydrogen is impossible for human senses to detect and can ignite over a much wider range of concentrations in air than other fuels. Combustion of hydrogen is more rapid than combustion of other fuels. Proper ventilation and the use of detection sensors can mitigate these hazards. UV overexposure is also a concern when handling hydrogen.

Liquid hydrogen has different characteristics and different potential hazards than gaseous hydrogen. Detection sensors and personal protective equipment are critical when dealing with a potential liquid hydrogen leak or spill. If spilled on ambient-temperature surfaces, liquid hydrogen will rapidly boil and its vapors will expand rapidly, increasing 848 times in volume as it warms to room temperatures. If large quantities of hydrogen displace the oxygen in the air, hydrogen will act as an asphyxiant. (H2 BestPractices website 2010, "Hydrogen Compared with Other Fuels", 26)

**Biofuels from Algae**

Producing transportation fuels from algae is a relatively new technology that is not currently commercialized. Therefore, DEQ propose that the safety concerns would need to be addressed at such a time when the techniques for fuel production are better established and understood.
12. Review of Rule

The low carbon fuel standards are a market based, dynamic regulation. As such, regular review will be necessary to keep it current with trends, technologies and other variables. As a result, DEQ staff propose the following review scenarios:

- **As needed:** DEQ proposes to review several elements of the rule as needed, such as fuel price and the need for exemptions and deferrals. See Table 9 on page 117 for a list of the program elements that may require as needed review. At any time, DEQ would appreciate feedback on the implementation of the rule, fuel quality and reliability, and compliance issues.

- **Annual:** DEQ proposes to evaluate specific program elements annually and report any significant issues to the Environmental Quality Commission. See Table 9 on page 117 for a list of these program elements.

- **2014 Review:** DEQ staff propose to review the low carbon fuel standards rule in either late 2013 or early 2014 in order to incorporate any advances in indirect land use change or other indirect effects, and to explore consistency with neighbor states (California and Washington).

- **Comprehensive 2016 Program Review:** DEQ proposes to evaluate key program elements and submit a report to the Environmental Quality Commission summarizing the department’s findings and recommendations.

Any proposed changes to the LCFS rule would require formal rulemaking, including a public review and comment period and adoption by the Environmental Quality Commission. See Table 9 on page 117 for a list of these program elements.

Table 9: Scope of Review for the Low Carbon Fuel Standard

<table>
<thead>
<tr>
<th>Program Element</th>
<th>Reviewed Annually</th>
<th>Reviewed 2014</th>
<th>Reviewed 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Fuel quality, and reliability issues and recommendations for addressing such issues</td>
<td>X (As needed)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>2. Identification of implementation and compliance issues and recommendations for addressing such issues</td>
<td>X (As needed)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>3. Fuel Price and Consumer Cost Safety Net review</td>
<td>X (As needed)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>4. The need for rule deferrals and exemptions</td>
<td>X (As needed)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>5. The low carbon fuel standards program’s progress against targets (compliance)</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>6. The availability and use of low carbon fuels to achieve the low carbon fuel standards;</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>7. The rates of commercialization of fuels and vehicles</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>8. Advances in fuel-lifecycle analysis (GREET modeling,</td>
<td>X</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Program Element</td>
<td>Reviewed Annually</td>
<td>Reviewed 2014</td>
<td>Reviewed 2016</td>
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<tr>
<td>-----------------</td>
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<tr>
<td>indirect land use change modeling, other indirect effects quantification)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9. The advisability of harmonizing with international, federal, regional, and other state low carbon fuel standards rules and lifecycle analysis. This review could also be triggered by the adoption of a federal low carbon fuels program.</td>
<td>X</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>10. Energy economy ratios, particularly energy economy ratios for all heavy-duty applications and light-duty CNG.</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>11. The advisability of allowing credit trading with other states that have a comparable low carbon fuel standards, and recommendations for the mechanics and standards of an inter-state trading program</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>12. Requirements for measuring electric vehicle use and review of which electrification activities qualify for credits.</td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>13. Adjustments to the compliance schedule, if adjustments are needed beyond the existing exemptions and deferrals already available in Oregon’s rule</td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>13. Inclusion of fuel used in locomotive engines in the low carbon fuel standards program beginning in 2017</td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>14. Identification of hurdles or barriers to increasing the use and supplies of low carbon fuels (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers</td>
<td></td>
<td></td>
<td>X</td>
</tr>
</tbody>
</table>

If federal low carbon fuel standards were adopted, DEQ would need to revisit the Oregon low carbon fuel standards.

DEQ finds that the proposed reviews (as-needed, annual, and comprehensive) will keep the program updated and address implementation issues that develop.

**Alternatives considered**

Alternative 1: No 2014 review. *Arguments in favor — 1)* DEQ initially did not propose a 2014 review. But after advisory committee members commented that a review prior to 2016 is necessary to address indirect land use change and other indirect effects, energy economy ratios, low carbon fuel standards in neighboring states, as well as other issues, DEQ added in a 2014 review.
DEQ investigated administrative updates to the rule at the advisory committee’s request. However, due to Oregon’s rulemaking laws, any changes to the rule could not be done administratively, and would need to involve rulemaking.

The advisory committee requested, and DEQ agrees, that if a federal low carbon fuel standard were adopted, DEQ would need to revisit the Oregon low carbon fuel standards.

Advisory committee input on this issue can be found in Appendix A.

13. Flexible Implementation Approaches to Minimize Compliance Cost

House Bill 2186 directs DEQ to consider flexible implementation approaches to minimize compliance cost. Some flexible implementation approaches are required by House Bill 2186, but the majority are optional.

Required by House Bill 2186

1. **Deferrals for adequate fuel supply**: DEQ can implement deferrals to ensure an adequate fuel supply. DEQ is proposing two types of fuel supply deferrals; a temporary supply deferral and a forecasted fuel supply deferral. In addition, there is a consumer cost safety net, which addresses the price of fuel (see #3 below).

2. **Consumer cost safety net**. If the 12-month rolling weighted average price of gasoline or diesel in Oregon becomes non-competitive with Washington, Arizona and Nevada due to a low carbon fuel standard, then the Environmental Quality Commission can implement exemptions and deferrals to mitigate compliance costs.

3. **Phased-in compliance schedule**. The phased-in schedule for compliance is back loaded and allows the development of new fuel technologies prior to large reductions in the low carbon fuel standard.

Not Required by House Bill 2186

1. **The low carbon fuel standards are market-based performance standards**. The market determines which technologies, fuels and fuel combinations can meet the standard cost effectively. There are many ways for regulated parties to comply with the low carbon fuel standards.

2. **Opt-in fuels**. Categorizing some types of low carbon fuel as opt-in provides important flexibility for the low carbon fuel standards program. Opt-in fuels generally have carbon intensities below the low carbon fuel standards and are expected to be used in small volumes in early program years. Opt-in parties (those producing or importing opt-in fuel) are specified in the rule, and can choose when it is beneficial to opt-in to the low carbon fuel standards program and earn credits, and can balance the benefits with the reporting requirements.

3. **Transfer of compliance obligation or credit with sale of fuel**. In some cases, the compliance obligation or credits can transfer from one regulated or opt-in party to another with the sale of fuel. This allows regulated parties a greater degree of compliance flexibility.
4. **Credits, deficits and trading.** Credits and deficits allow regulated parties more options for compliance.

   a. **Banking credits** allows a regulated party to save earned credits for the future.

   b. **Carry-over of “small” deficit amounts** gives a regulated party compliance flexibility to make up a small deficit in the next compliance period.

5. **Updating or adding to the carbon intensity lookup table (new fuel pathways).** The ability to update or add a carbon intensity to the lookup table means that a regulated or opt-in party can obtain a new carbon intensity number for significant improvements in a fuel production process. For statewide carbon intensities, the table will be updated to reflect the current average carbon intensity for the fuel. By updating the table, the low carbon fuel standards program can respond to and accommodate new fuel types and feedstocks.

6. **Exemption for small volume fuel producers.** Exemptions allow for innovative fuels development, or fuels used in small quantities to become established in the market until a volume threshold is reached that will require compliance with the low carbon fuel standards.

7. **Future review of rule.** Regular, scheduled low carbon fuel standards review allows DEQ to respond to issues that might arise from program implementation. Some topics are proposed to be reviewed as needed, some annually, and some in comprehensive program reviews.

   *Advisory committee input on this issue can be found in Appendix A.*

14. **Effect of the Sunset**

Pursuant to House Bill 2186, the authority to implement Low Carbon Fuel Standards in Oregon will sunset on December 31, 2015 unless the Oregon Legislature lifts that sunset. The sunset was added to House Bill 2186 to ensure the legislature has an opportunity to review the details of the low carbon fuel standards program and the final outcome of DEQ’s rulemaking process. DEQ intends to propose low carbon fuel standards program rules for Environmental Quality Commission adoption in 2011, with a compliance schedule established through 2022.

**House Bill 2186**

SECTION 8. Sections 6 and 7 of this 2009 Act are repealed on December 31, 2015.

SECTION 9. (1) The Department of Environmental Quality shall report on the implementation of sections 3 and 6 of this 2009 Act to:

   (a) The interim legislative committees on environment and natural resources on or before December 31, 2010; and

   (b) The Seventy-sixth, Seventy-seventh and Seventy-eighth Legislative Assemblies in the manner provided by ORS 192.245.

   (2) The reports required under subsection (1) of this section must contain a description of:

   (d) The anticipated effects of the December 31, 2015, repeal of sections 6 and 7 of this 2009 Act on the availability of low carbon fuels and the development of biofuels production facilities and electric vehicle infrastructure in Oregon.

House Bill2186 directs DEQ to report to the legislature on the possible effects of the December 31, 2015 repeal (sunset) of the low carbon fuels standards. This includes considering the potential
consequences and effects of low carbon fuel standards, or absence of such standards, on the availability of low carbon fuels and the development of biofuels production facilities and electric vehicle infrastructure in Oregon. DEQ does not intend to propose legislation in 2011 to lift the sunset, since the rules will not be adopted until after the 2011 session. Following are possible consequences of a low carbon fuel standards sunset in December 2015.

A. Implementation and Enforcement
The first practical consequence of the sunset is that DEQ would be unable to implement or enforce the low carbon fuel standards program after December 31, 2015. The standards and compliance obligations for regulated parties would cease to exist on January 1, 2016. As a result, DEQ could invest resources in program outreach and technical assistance, develop compliance verification methods and program infrastructure to serve only a 4-year program period (2012-2015). As a practical matter, DEQ would likely not impose any reporting or compliance obligations until such time as the sunset is lifted.

B. In-State Biofuels Production
DEQ’s fuels assessment and compliance scenarios anticipate the growing capacity in Oregon to produce bio-fuels. Bio-fuels production, both inside and outside of Oregon, will grow in response to federal renewable fuel standards. Absent an Oregon low carbon fuel standard, one might still expect some continued growth in Oregon’s Biofuels industry. However, it also seems reasonable to expect that the existence of an Oregon’s low carbon fuel standards would be a significant incentive to increase the production capacity of Oregon’s existing Biofuels facilities and attract new biofuels production.

Presumably, the uncertainty of a program sunset in 2015 would be a significant obstacle to attracting new investment in Biofuels production. Any delay in development of new Biofuels capacity could contribute to a deficit in low carbon fuel supply in later years of the program (if reauthorized), since it likely takes several years to develop, finance, and construct a Biofuels production facility. Such a delay in building Oregon’s biofuels capacity could make it much more difficult for regulated parties to meet the standards, resulting in higher compliance costs, and possibly triggering compliance deferrals and/or deferrals under the consumer cost safety net.

C. Low Carbon Fuel Credits
Any low carbon fuel credits developed and banked in the initial years of the program would become unnecessary, and of no value, if the program sunsets at the end of 2015.

D. Electric Vehicle Infrastructure
DEQ’s fuels assessment and compliance scenarios anticipate the growing desire and capacity in Oregon to use electric vehicles, both in urban and rural areas of the state. Many initiatives are currently underway to increase the use of electric vehicles in Oregon, and the Oregon Public Utility Commission has initiated an investigation into how the current regulatory landscape for utilities may need to evolve to accommodate increased electric vehicle use. Increased electric vehicle use will be driven by both customer demand, and by the Oregon Low Emission Vehicle program, which requires zero emission vehicles as part of the overall mix of new low emission vehicles sold in Oregon.
The existence of a low carbon fuel standards program would likely increase the incentive to expand the electric vehicle population in Oregon. In addition, electricity used for transportation fuel can be used to generate low carbon fuel credits, which can then be sold to a regulated party.

Presumably, a low carbon fuel standards program sunset in 2015 would remove this additional incentive for electric vehicle development; however, electric vehicle deployment in the state would continue due to other initiatives.

Advisory committee input on this issue can be found in Appendix A.

VII. Calculating Carbon Intensities for Oregon Transportation Fuels

House bill 2186, the authorizing statute for the low carbon fuel standards allows DEQ to evaluate the carbon intensity of a fuel based on a lifecycle assessment, which includes, but is not limited to greenhouse gas emissions from the production, storage, transportation, and combustion of fuels and from changes in land use associated with the production of fuels. Lifecycle assessment of a fuel’s carbon intensity is important because tailpipe emissions are only a portion of the total emissions related to transportation fuel. To evaluate the carbon intensity for each fuel, DEQ looked at the greenhouse gas emissions from extracting or growing the feedstock, refining, storage, transportation, and combustion, and then adjusted the carbon intensity to account for:

1. Co-products produced with biofuels that have economic value and displace greenhouse gas emissions that would have been generated from growing other crops;

2. Indirect land use change effects; and

3. The increased or decreased fuel economy and drive train of alternative vehicles (Energy Economy Ratio).

In order to develop carbon intensities for fuels (particularly gasoline and diesel), Oregon DEQ staff worked closely with the State of Washington and their contractor to use consistent information, consistent methodologies, and to avoid duplication of work. Oregon also took relevant information from California’s low carbon fuel standard lifecycle analysis, and from the EPA’s federal Renewable Fuel Standard 2 lifecycle analysis.
1. Direct Lifecycle Analysis

A. Overview

The direct carbon intensity of a fuel is calculated by adding up greenhouse gas emissions from each step in the fuel production process. For example, for soybean biodiesel, the following information would be used in calculating the direct carbon intensity:

- Farming practices, such as the frequency and type of fertilizer used in producing the soybeans;
- Soybean yield per acre;
- Soybean harvesting practices and collection;
- Transportation to the fuel production facility;
- Efficiency of the fuel production facility and process;
- Type of fuel used in the production process (Coal/Natural Gas/Biomass);
- Energy efficiency of the production process;
- Transport and distribution of the fuel; and
- Vehicle combustion of the fuel.

The emissions from each step in the soybean fuel production process would be summed. Refining biomass into fuels can also produce economically viable co-products that can substitute for products that would otherwise have generated greenhouse gas emissions. The foregone greenhouse gas emissions from co-product use are subtracted from a fuel’s carbon intensity. For example, in the dry-mill process of ethanol production, 56 pounds of corn will yield 2.8 gallons of ethanol and 17.5 pounds of animal feed (dried distillers grains). Because this co-product displaces some other crop, the greenhouse gas emissions that are not generated by growing corn to feed cows due to the use of 17.5 pounds of animal feed are subtracted from the carbon intensity of ethanol. Please see Figure 15 on page 124.
Alternatives considered

Alternative 1: Ensure that if the carbon emission reductions of the co-product are attributed to the fuel carbon intensity, then there is no other way that they can market those reductions in the channels for the co-products. *Arguments in favor — 1) This would reduce doublecounting.*

Rationale for DEQ Proposal

Co-products produced with biofuels have economic value and displace greenhouse gas emissions that would have been generated from growing other crops, it is therefore appropriate to adjust carbon intensity values to account for co-products.

B. Calculation Methodology for Carbon Intensity of Oregon’s Fuels

For some fuels, DEQ calculated statewide carbon intensities, while for others, DEQ calculated the carbon intensity based on a specific production process. These carbon intensity numbers are found in the carbon intensity lookup table (see page 76).

- For gasoline, diesel, electricity and compressed fossil North American natural gas delivered via pipeline, DEQ has calculated one carbon intensity value that reflects the average of that fuel’s use in Oregon.
The one exception is that an electricity provider who only provides electricity for transportation and is exempt from Oregon Public Utility Regulation by ORS 757.005 (1)(b)(G) can obtain a carbon intensity number specific to the electricity they supply.

- For ethanol, biomass-based diesel, LNG, biogas (CNG and LNG), any CNG that includes a stage in which it was LNG, hydrogen, and any new fuel, the carbon intensity of the fuel is dependent on the individual producer’s fuel pathway and production process.

For information on updating carbon intensities and adding carbon intensity numbers to the lookup table (new fuel pathway process), please see page 78.

House Bill 2186 authorizes DEQ to reduce the statewide average carbon intensity of Oregon’s fuels. Using a statewide average for gasoline, diesel, electricity and CNG imported to Oregon in a non-liquefied form is consistent with this goal. See the section on Rationale for DEQ’s proposal below.

**Figure 16: CNG Pathways and Carbon Intensity**
Alternatives considered

**Gasoline and Diesel**

Alternative 1: Individual carbon intensities for each gasoline or diesel producer, instead of a statewide average for all producers. *Arguments in favor — 1) Consistency with biofuels. 2) Individual carbon intensities are a better way to incent lower carbon petroleum.*

Alternative 2: Gasoline and diesel producers able to obtain individual carbon intensity if refinery efficiency improves by 5 gCO2e/MJ or 10 percent, whichever is less. *Arguments in favor — 1) If an individual refinery makes efficiency improvements to their production process, it should be reflected in their carbon intensity.*

**Electricity**

Alternative 3: Individual carbon intensities for each electric utility and electricity provider. *Arguments in favor — 1) The carbon intensity of electric utilities varies greatly, and utilities with lower carbon intensity should earn more credits.*

Alternative 4: Electricity uses new resource electricity carbon intensity. *Arguments in favor — 1) The carbon intensity for electricity should reflect only new generation power added to meet increased transportation electricity demand.*
Carbon intensity of electricity used to produce fuels

Alternative 5: For production of fuels, production facilities can use a carbon intensity that represents the actual electricity used in fuel production, rather than a state or regional average. *Arguments in favor — 1) The electricity used by some fuel production facilities is lower in carbon intensity than the statewide average. This affects the carbon intensity of the finished fuel, which could be lower the carbon intensity of electricity used in fuel production is individual, rather than an average.*

Rationale for DEQ Proposal

DEQ’s proposal maintains a balance between workload and detail.

Because House Bill 2186 authorizes reduction in the statewide carbon intensity of Oregon’s fuels, it is consistent to use statewide averages of carbon intensity for some fuels. There are different reasons for using the statewide averages for gasoline, diesel, electricity and CNG imported to Oregon in a non-liquefied form.

CNG imported to Oregon in a non-liquefied form: The carbon intensity of CNG imported to Oregon in pipelines (or produced in Oregon) is relatively uniform, so a statewide average is used to simplify and reduce the barriers for providers of CNG to opt-in.

Electricity: DEQ, supported by the advisory committee, chose to propose statewide average carbon intensity for several reasons: it creates a level playing field between geographic areas, the carbon intensity is expected to decrease due to the Renewable Portfolio Standard, and an average would equitably represent the carbon intensity of Oregon’s electricity as a whole. Does not create a geographical bias for electric vehicle investment based on the carbon intensity of local electricity. A statewide average is easier and provides more regulatory certainty. Based on DEQ’s conversations with utilities, the use of individual carbon intensities is unlikely to motivate utilities to reduce the carbon intensity of their electricity or affect their decision to opt-into the low carbon fuel standards program.

For electricity used in fuel production, DEQ proposes to use statewide or regional average carbon intensities, due to workload issues. Ideally, DEQ could accommodate requests to individualized carbon intensities for production electricity. This would require substantial staff to accommodate requests from fuel producers.

Gasoline and diesel: Tracking the carbon intensity of individual fuel producers would be overly burdensome on regulated parties.
C. Lifecycle Analysis for Fuel Made from Waste

For fuel made from waste products, the lifecycle analysis of carbon intensity begins when the use of the product for its’ original intent ends. This means that the greenhouse gas emissions from the production and previous use of the feedstock prior to it becoming waste are not included in the carbon intensity calculation. In general, the lifecycle analysis in this case begins with the collection of the waste for use as a fuel, and continues with the refining, storage, transport, and use of the fuel.

For example, the main purpose of cooking oil is to cook food. After it has served that purpose, it can be collected and made into biodiesel. For biodiesel made from waste cooking oil, the lifecycle analysis begins with the collection of the waste cooking oil. In the example in Figure 18 on page 128, the carbon emissions from growing, harvesting and removing wheat are excluded from the lifecycle analysis of fuel made from wheat straw. The lifecycle analysis for fuel made from wheat straw begins with the collection of the wheat. Other examples of feedstock that is considered waste include, but are not limited to tires, waste plastics, corn stover, mill waste, and wheat and grass seed straw. Crops grown for the purpose of making fuel are not considered waste.

Lifecycle assessment of the carbon intensity begins when the original product becomes waste. The lifecycle assessment of waste begins with its collection for use as a fuel, through refining, storage, transport, and use of the fuel. Nothing in the materials life prior to it becoming waste is included in the carbon intensity calculation.

Figure 18: Example Lifecycle Analysis for Fuel Made from Waste
D. Lifecycle Analysis for Fuels Made from Biomass versus Fuels Made from Petroleum Products

As biomass grows, it removes carbon dioxide from the atmosphere during photosynthesis. When biomass or a biomass-based fuel is burned, it returns the carbon to the atmosphere, again in the form of carbon dioxide, resulting in no net carbon dioxide emissions. Consequently, carbon dioxide emissions from combusting biomass-based fuel are assumed to be zero in the lifecycle analysis. This assumption - a "steady state" of carbon dioxide uptake (from the atmosphere to biomass) and release (from biomass to the atmosphere) - is predicated on the use of biomass not being associated with land use changes. However, other greenhouse gases, which are generated from combustion of biomass are included in the lifecycle analysis. For example, when biodiesel is combusted, small amounts of methane and N2O are produced. These are included in the lifecycle analysis.

In contrast, carbon from fossil fuel sources is withdrawn from the earth, where it has been sequestered, and then released into the atmosphere upon combustion. Therefore, the carbon dioxide from combusting fossil fuels is included in the lifecycle analysis, including fuels made from products containing petroleum (such as tires and waste plastic).

Alternatives considered

Alternative 1: This method of calculating emissions from biomass should include short life and waste biomass only. Biomass sources that grow on a short cycle are very different from trees grown on a 40-year or more cycle. Arguments in favor — 1) this will alleviate the concern about “whole logs” as feedstock to fuels.

E. Models Used on Lifecycle Analysis

GREET is a lifecycle analysis model developed by Argonne National Lab. It is designed to calculate the energy use and greenhouse gas emissions associated with the production and use of fuels. GREET includes more than 100 fuel production pathways from various energy feedstocks. GREET looks at inputs such as crude recovery energy consumption, refining equipment consumption, losses, transport distances and mode of transport, feedstock material, farming and feedstock collection energy use, fertilizer and pesticide inputs, crop yields and process efficiency.
Figure 19: GREET Fuel Production Pathways

DEQ staff have customized GREET for Oregon (OR-GREET). For a description of inputs and assumptions, please see Appendix B: Lifecycle Analysis.

GREET calculates the carbon intensity of a fuel based on user inputs. Following are examples of Oregon petroleum pathways and key inputs for the petroleum pathways. For details on pathways, key inputs and assumptions for Oregon’s fuels, please see Appendix B: Lifecycle Analysis.
Figure 20: Oregon Petroleum Pathways

Oregon Petroleum Pathways

- Crude Production
  - Alaska
  - Canada
  - Africa
  - South America
  - Middle East

- Refinery
- Blending Terminal
- Retail
- Port
- Pipeline
- Ship
- Truck

- Refineries in WA, Utah, Montana, California, overseas
- Terminals in Portland, Eugene, Pasco, Vancouver, WA

Portland terminals:
- Paramount Petroleum
- ConocoPhillips
- Chevron Products
- Kinder Morgan
- LP Shore Terminals
- BP West Coast Products

Slide 11
Petroleum Pathways – Key Inputs/Assumptions

- **Process Efficiency**
  - Crude Recovery Energy Consumption
  - Refining Energy Consumption

- **Fuel and Equipment Mixes**
  - Crude Recovery
  - Refining

- **Losses (recovery, refining)**

- **Transport**
  - Distances by mode
  - Tanker/Truck Inputs
    - Payload
    - Horsepower
    - Fuel economy
    - Speed
  - Pipeline Inputs
    - Energy intensity (Blu/ton-mile)
    - Compressor station fuel mix
    - Prime mover mix at compressor stations
  - Losses

For an example of a biofuels pathway, we have included ethanol pathways and key inputs for the ethanol pathways.
For more details on the specific inputs, assumptions, and modifications used in calculating carbon intensity for Oregon’s fuels, please refer to Appendix B: Lifecycle Analysis.

**Alternatives considered**

Alternative 1: Advisory committee members asked about using other transportation emission models.

Alternative 2: Include a model that addresses the energy returned on energy invested ratio.

*Arguments in favor — 1) Energy should not be wasted for lower emissions.*

**Rationale for DEQ Proposal**

DEQ uses GREET because it is a well-developed, publicly accessible model. Other models do not account for lifecycle greenhouse gas emissions.

*Advisory committee input on this issue can be found in Appendix A.*
2. **Indirect Land Use Change and Other Indirect Effects**

A. **Indirect Land Use Change**

The Low Carbon Fuel Standards could promote the increased use of biofuels in the future. A large increase in acreage needed to produce biofuels crops could displace acres needed to produce food crops. This could lead to non-agricultural lands being converted to cropland. In the conversion process, carbon that may have remained otherwise sequestered in soils and cover vegetation is released. Initially, there would be a large emission of carbon due to land conversion, and reduced emissions continued over time. This is what is known as indirect land use change (ILUC) effect.

This is an emerging scientific field and the data analysis to quantify this effect is in its infancy. In order to gain more information relevant to a decision on indirect land use change and to better educate the advisory committee with regard to the science of calculating indirect land use change, DEQ contracted with TIAX, LLC to analyze and compare different indirect land use change methodologies. TIAX compared three calculation methodologies for indirect land use change associated with different fuel types performed to date. These include:

- US Environmental Protection Agency (EPA) Analysis
- California Air Resources Board (CARB) Analysis
- Purdue University and GTAP (Purdue/GTAP Analysis)

TIAX also reviewed results based on a letter to EPA from the Renewable Fuels Association who commented on EPA’s method. The TIAX Indirect Land Use Change Comparative Analysis can be found in *Appendix E: Comparable Economic Studies in Other States*. The modeling approaches and assumption values are significantly different for each method, and as a result, the numbers vary widely. **Figure 22** on page 136 shows the indirect land use change value for each method for corn ethanol, soybean biodiesel, and sugarcane ethanol.
In their report, TIAX provides a detailed comparison of:

- General Modeling Methodologies
- Land Use Change Estimates (land area, location, prior use)
- Elasticity Assumptions
- Co-Product Assumptions
- Emission Factors and Sequestration

TIAX concluded that it is difficult to determine which set of values is the most representative of actual indirect land use change emissions, but note that the methodologies and tools used to estimate indirect land use change have improved during the past several years, and that there are ongoing efforts to continue improving and refining the modeling methodologies.

DEQ recognizes that indirect land use change exists, and that carbon intensity values in a low carbon fuel standard program should be adjusted to account for this effect. However, given the developing state of the science, DEQ proposes to begin the low carbon fuel standards program without using any indirect land use change values. DEQ will review the available methodologies for calculating indirect land use change again in 2014 to determine if indirect land use change can be added to the program at that point. If indirect land use change is not added in 2014, DEQ intends to review the issue again in the 2016 comprehensive low carbon fuel standards program review. When carbon intensity values are adjusted for indirect land use change, the 2010 baseline would also need to be recalculated using indirect land use change numbers. At that time, any banked credits would also be adjusted. (see section on credits and deficits on page 87)
Why is this so important? The inclusion of an indirect land use change factor can significantly increase the carbon intensity of a fuel. In the cases of Brazilian sugarcane ethanol and Midwest soybean biodiesel, the California Air Resources Board indirect land use change values outweigh the direct emissions of these fuels. This will drastically alter the way regulated parties strategize to comply with the low carbon fuel standards.

Table 10 on page 137 contains the direct carbon intensity for some of Oregon’s biofuels, and then the indirect land use change value for the three methodologies. As you can see, indirect land use change can make up a significant portion of the fuel’s carbon intensity, depending on the methodology used.

Table 10: Comparison of Direct and Indirect Carbon Intensity Values

<table>
<thead>
<tr>
<th>Pathway</th>
<th>Direct OR GREET g CO₂e/MJ</th>
<th>Indirect Land Use Changes</th>
<th>CARB g CO₂e/MJ</th>
<th>EPA g CO₂e/MJ</th>
<th>Purdue g CO₂e/MJ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethanol, MW Corn, MW Production</td>
<td>64.82</td>
<td>30.00</td>
<td>26.00</td>
<td>14.00</td>
<td></td>
</tr>
<tr>
<td>Ethanol, MW Corn, NW Production</td>
<td>56.99</td>
<td>30.00</td>
<td>26.00</td>
<td>14.00</td>
<td></td>
</tr>
<tr>
<td>Ethanol, Farmed Trees</td>
<td>15.54</td>
<td>5.00*</td>
<td>3.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethanol, Brazilian Sugarcane</td>
<td>26.44</td>
<td>46.00</td>
<td>5.00</td>
<td>**</td>
<td></td>
</tr>
<tr>
<td>Biodiesel, MW Soybeans</td>
<td>19.99</td>
<td>62.00</td>
<td>32.00</td>
<td>**</td>
<td></td>
</tr>
</tbody>
</table>

* California Air Resources Board (CARB) used the switchgrass value (18) for farmed tree ethanol. Because the yield/acre for poplar is much higher than switchgrass, the carbon intensity is adjusted accordingly.

** Purdue also estimated new indirect land use changes for Brazilian sugarcane ethanol and Midwest soybean biodiesel but have yet to report out on the results.

Alternatives considered

Alternative 1: Adjust carbon intensity with California Air Resources Board or EPA indirect land use change values. Arguments in favor — 1) California Air Resources Board’s indirect land use change values are the most vetted.

Alternative 2: Adjust carbon intensity with an average of carbon intensity values available. Arguments in favor — 1) It will be less of a change for participants in the low carbon fuel standards to adjust an existing indirect land use change value than to add one in. Therefore, the average is a good choice.

Arguments in favor of both Alternatives 1 and 2: 1) Indirect land use change is real. Including it is the only way to accurately reflect the carbon intensity of fuels, 2) including some indirect land use change now would provide a correct signal to the market, and
provide regulatory certainty 3) Not including indirect land use change is just as much of a decision as choosing one of the current methodologies. 4) Having indirect land use change in the rule from the beginning would favor lower carbon fuels faster. 5) The way California addressed indirect land use change allows for a smaller adjustment later. There is enough evidence that indirect land use change should be included. 6) There are real unintended consequences – it is not fair. 7) Fuels vulnerable to indirect land use change may oversell their product with less benefits while truly low carbon fuels that provide greater benefits are harmed. 8) Adding an indirect land use change value later on will disrupt the market.

Alternative 3: Do not add indirect land use change values for biofuels without a corresponding indirect effect analysis and number for all fuels. Arguments in favor — 1) All fuels have indirect effects 2) For fairness, it is important for indirect numbers for all fuels (including indirect land use change) to be added at the same time. 3) Including indirect land use change and not other indirect effects disadvantages some fuels.

Alternative 4: Include in rule that indirect land use change will be included in 2014. Arguments in favor — 1) If a firm date is not in rule, this could be delayed.

Rationale for DEQ Proposal

Calculating indirect land use change is a nascent field with data analysis rapidly advancing. DEQ’s contractor recommended adjusting carbon intensity values for indirect land use change later when the science has matured more.

DEQ could update the baseline using the data used in setting the original (2007, 2009 for high carbon intensity crudes from Canada). DEQ is not proposing this option because using actual 2010 data would be more accurate.

B. Other Indirect Effects

In addition to the indirect land use change effect, there are other indirect effects that occur as a result of increased fuel production. These other effects include things such as impacts to water quality, water quantity, price of food, habitat loss, military emissions, and other ecological effects. The committee discussed these considerations, however, the science is not available yet to quantify these effects for inclusion into this low carbon fuel standards. Some of these topics are discussed in the section on Potential Impacts to Public Health and the Environment on page 155. When indirect effects are included, DEQ will recalculate the 2010 baseline using carbon intensities adjusted for indirect effects. At that time, DEQ will adjust any banked credits to account for indirect effects. The result would be that a banked credit might be reduced some percentage, and a regulated or opt-in party would have less banked credits as a result. (See discussion on banked credits on page 87). Past compliance would not be affected. There would be some time period before the credits were adjusted.
Alternatives considered

Alternative 1: Do not consider adjusting carbon intensity values to account for any indirect effects. Arguments in favor — 1) indirect effects other than indirect land use change are too difficult to quantify.

Alternative 2: Adjust carbon intensity values to account for indirect effects now. Arguments in favor — 1) all fuels have indirect effects. The indirect effects of petroleum fuels should be considered. 2) It is unwise and scientifically unjustified to burden one fuel with an indirect impact (indirect land use change) if we are not burdening other fuels with their specific market mediated impact.

Alternative 3: Include the emissions from the military’s equipment to protect the transport of oil from the Middle East. Arguments in favor – 1) Indirect effects should apply to petroleum fuels consistently with biomass-based fuels.

Rationale for DEQ Proposal

DEQ is not adjusting carbon intensity values to account for indirect effects at this time because the science of quantifying indirect effects is still in development. After receiving many advisory committee comments on this issue, DEQ will consider including indirect effects when the calculation methodologies are sufficient. Indirect effects could be added separately from indirect land use change, depending on the adequacy of the science.

Advisory committee input on this issue can be found in Appendix A.

3. Energy Economy Ratios (EERS) and Drive Train Efficiencies

In order to compare the relative carbon intensity (per unit of energy) of electricity and other alternative fuels to that of gasoline and diesel, the drive train efficiency of alternatively powered vehicles must be accounted for. Conventional vehicles lose most of their fuel’s energy to inefficiencies in the operation of internal combustion engines and elaborate drive trains. These losses include idling; heat lost from combustion; pumping losses (drawing air through filters, compressing it in combustion chambers and expelling it through an exhaust system) and mechanical losses (valve trains, gear boxes, water pumps, etc.). By comparison, electric vehicles are very efficient: they operate only as needed, give off far less unused heat, and do not need to drive the complex machinery of a combustion engine. For example, in an average conventional internal combustion car only thirteen percent of fuel energy reaches the tires to move the car; the rest is lost to inefficiencies in the engine and drive train. In a typical electric vehicle however, 61 percent of fuel energy is available to move the vehicle. As a result, they have a lower per mile energy consumption and greenhouse gas emission per mile.

The carbon intensity values for alternative fuels such as electricity and hydrogen needs to take into account the fact that, because of their fuel economy, they emit less greenhouse gases than gasoline vehicles on a per mile basis. The carbon intensity for heavy-duty natural gas vehicles needs to take into account the decreased fuel economy compared to similar diesel vehicles. Accounting for the difference in fuel economy is accomplished using an energy economy ratio (EER).
EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel (gasoline or diesel).

\[
EER = \frac{\text{# of miles driven/unit of energy consumed}}{\text{# of miles driven per unit of energy for reference fuel}}
\]

For example, for a certain amount of fuel energy, an electric vehicle will drive four times more miles on average than a similar gasoline vehicle. Similarly, a heavy-duty natural gas vehicle will drive fewer miles than a similar diesel vehicle using the same amount of fuel energy.

Figure 23 on page 140 illustrates this for light-duty gasoline and electric vehicles.

The EER can also be used to compare the total CO2 emissions from different types of fuels and vehicles without having to calculate gram per mile values. This allows the metric of grams CO2 per MJ to be used in the low carbon fuel standards regulation, which is a much more convenient for comparison.
metric for regulatory and enforcement purposes than the gram per mile metric. (CA EPA Resources Board, 2009. Proposed Regulation 2 App. C1, 27)

DEQ staff propose to base EERs for Oregon on California Air Resources Board research. (CA EPA Resources Board, 2009. Proposed Regulation 2 App. C1, 28) In order to calculate EERs, California Air Resources Board compared the distance a conventional vehicle can travel on a given unit of energy to the distance an alternative vehicle can travel on the same amount of energy. There are two adjustments that DEQ proposes for light-duty EERs. First, DEQ has adjusted California Air Resources Board’s EER to reflect the fact that Oregon does not currently use reformulated gasoline, and therefore, the EERs are slightly higher than California’s. Next, DEQ staff propose to take into account the fact that although new light-duty gasoline vehicles sold in 2016 and later will be 30 percent more efficient than 2002 vehicle fleet average due to Oregon’s Low Emission Vehicle standards (Pavley standards), the vehicle fleet on the road today is not 30 percent more efficient. The light-duty gasoline fleet in Oregon will become gradually more efficient as the fuel economy standards phase-in and as the fleet turns over. To account for this gradual improvement in gasoline light-duty vehicle fuel improvement, DEQ staff propose to use a declining EER for light-duty electric and hydrogen vehicles for the ten years of the program. DEQ staff propose to review the light-duty CNG EER in 2014 and 2016.

EPA has a proposal for fuel economy improvements for heavy-duty and medium-duty vehicles. Because these rules have not been finalized, DEQ staff propose to use the same EER for heavy-duty applications throughout the 10-year program period, with reviews in 2014 and 2016 to investigate whether or not the EERs should be updated.

DEQ proposes that if the EER of a vehicle type changes substantially, DEQ could make changes to the EER table. DEQ will also review the EERs used for the Oregon low carbon fuel standards as part of the Department’s 2014 and Comprehensive 2016 low carbon fuel standards Program Review process.

Oregon DEQ proposes to use the Energy Economy Ratios (EERs) listed in the tables below. There are two separate tables. Table 11 on page 142 contains the EERs for light-duty applications, which substitute for gasoline. Table 12 on page 142 contains the EERs for heavy-duty applications, which substitute for diesel.
### Table 11: EER Values for Fuels Used in Light-Duty Applications

<table>
<thead>
<tr>
<th>Year</th>
<th>Gasoline or any ethanol blend</th>
<th>CNG / Internal combustion engine vehicle</th>
<th>Hydrogen or fuel cell vehicle</th>
<th>Electricity / battery electric vehicle, or plug-in hybrid electric vehicle</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1.0</td>
<td>1.0 (needs to be adjusted: not reformulated gasoline)</td>
<td>3.0 (needs to be adjusted: not reformulated gasoline)</td>
<td>4.1</td>
</tr>
<tr>
<td>2013</td>
<td>1.0</td>
<td>1.0</td>
<td>3.0</td>
<td>4.0</td>
</tr>
<tr>
<td>2014</td>
<td>1.0</td>
<td>1.0</td>
<td>2.9</td>
<td>3.9</td>
</tr>
<tr>
<td>2015</td>
<td>1.0</td>
<td>TBA*</td>
<td>2.8</td>
<td>3.8</td>
</tr>
<tr>
<td>2016</td>
<td>1.0</td>
<td>TBA</td>
<td>2.8</td>
<td>3.7</td>
</tr>
<tr>
<td>2017</td>
<td>1.0</td>
<td>TBA</td>
<td>2.7</td>
<td>3.6</td>
</tr>
<tr>
<td>2018</td>
<td>1.0</td>
<td>TBA</td>
<td>2.6</td>
<td>3.5</td>
</tr>
<tr>
<td>2019</td>
<td>1.0</td>
<td>TBA</td>
<td>2.5</td>
<td>3.4</td>
</tr>
<tr>
<td>2020</td>
<td>1.0</td>
<td>TBA</td>
<td>2.5</td>
<td>3.3</td>
</tr>
<tr>
<td>2021</td>
<td>1.0</td>
<td>TBA</td>
<td>2.4</td>
<td>3.2</td>
</tr>
<tr>
<td>2022</td>
<td>1.0</td>
<td>TBA</td>
<td><strong>2.3</strong></td>
<td><strong>3.1</strong></td>
</tr>
</tbody>
</table>

*In the 2014 review, DEQ will research what the EER for light-duty CNG should be after 2014.

*Data in this table is based on:* California Environmental Protection Agency Air Resources Board. Appendices, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. 2. Appendix C, pages C-5 through C-12. Released Date March 4, 2009.

### Table 12: EER Values for Fuels Used in Heavy-Duty Applications

<table>
<thead>
<tr>
<th>Diesel fuel or Biomass-based diesel blends</th>
<th>CNG or LNG</th>
<th>Hydrogen or fuel cell vehicle</th>
<th>Electricity / battery electric vehicle, or plug-in hybrid electric vehicle</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>0.94</td>
<td>1.9</td>
<td><strong>2.7</strong></td>
</tr>
</tbody>
</table>

*DEQ will research what the EER for all heavy-duty applications should be in future years in the 2014 review*

*Data in this table is based on:* California Environmental Protection Agency Air Resources Board. Appendices, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. 2. Appendix C, pages C-5 through C-12. Released Date March 4, 2009.
California Air Resources Board Methodology for Calculating EER

California Air Resources Board staff used the fuel economy data published by the U.S. EPA and US Oregon Department of Energy in the Fuel Economy Guide for light duty CNG vehicles, battery electric vehicles and fuel cell vehicles. This information was supplemented by staff with estimates of fuel economy for some light duty battery electric vehicles and plug-in hybrid electric vehicles operating in the grid electricity mode using information on vehicle range and battery capacity. Table 13 on page 143 outlines California Air Resources Board’s methodology and data sources for calculating EERs.

Table 13: California Air Resources Board Methodology for Calculating Energy Economy Ratios

<table>
<thead>
<tr>
<th>Alternative Vehicle</th>
<th>Methodology for calculating Energy Economy Ratios</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery Electric Vehicles</td>
<td>To calculate the EER for battery electric vehicles, California Air Resources Board staff used data from three vehicles (the 2000 Nissan Altra, the 2003 Toyota RAV4, and 2006 AC Propulsion eBox) that are the most representative in terms of size and technology of the battery electric vehicles that are most likely to be produced and used in the future. The EERs for the Nissan Altra, the Toyota RAV4, and their corresponding gasoline reference vehicles were calculated using the fuel economy data from the U.S. EPA/US Oregon Department of Energy Fuel Economy Guide. For the AC Propulsion eBox, the energy efficiency and fuel economy was estimated from published data on the vehicle’s range and battery capacity, whereas the fuel economy of the gasoline reference vehicle (the Scion xB) was obtained from the EPA/ US Oregon Department of Energy Fuel Economy Guide.</td>
</tr>
<tr>
<td>Plug-in Hybrid Electric Vehicles</td>
<td>To calculate the EER for plug-in hybrid electric vehicles, California Air Resources Board staff assumed that this type of vehicle would achieve energy efficiency and fuel economy comparable to that of the Chevy Volt expected to be sold commercially in 2010. California Air Resources Board staff estimated the fuel economy of Chevy Volts based on the estimated range of the vehicle as well as it’s battery capacity, in the absence of available test data at that time.</td>
</tr>
<tr>
<td>Combination of Light Duty Battery Electric and Plug-in Hybrid Electric Vehicles</td>
<td>Due to limited data available on the fuel economy of both battery electric and plug-in hybrid electric vehicles, and the fact that some of the estimates available are based on driving cycle data while others are based on calculations, California Air Resources Board staff were not confident in the difference in the estimated EER between the two vehicle types, and decided to average the adjusted EERs for both battery electric and plug-in hybrid electric vehicles, and arrived at an EER value of 3.0.</td>
</tr>
<tr>
<td>Fuel Cell Vehicles</td>
<td>The fuel economy of the commercially available 2009 Honda Clarity FCX was used by California Air Resources Board staff to estimate the EER for fuel cell vehicles.</td>
</tr>
</tbody>
</table>
Alternative Vehicle | Methodology for calculating Energy Economy Ratios
--- | ---
Light Duty CNG Vehicles | California Air Resources Board staff used the fuel economy of the commercially available 2008 Honda Civic to estimate the EER for light duty CNG vehicles.
Heavy Duty Fuel Cell Vehicles | The EER for heavy-duty vehicles used by California Air Resources Board is based on the averaged results of an NREL-funded test program conducted on transit buses.
Heavy Duty Engines Using CNG or LNG | To reflect recent improvements in the fuel economy of CNG relative to diesel in transit buses (the vehicle type which uses the largest portion of CNG as a transportation fuel), California Air Resources Board staff selected the EER value of 0.9 for the Cummins Westport heavy duty CNG engine, known as the ISL G, to represent the energy economy ratio to be used when comparing emissions from heavy duty CNG vehicles to those generated by heavy-duty diesel engines. California Air Resources Board staff will review test data from other CNG engine technologies as it becomes available and revise the EER for heavy-duty CNG engines, if necessary. (CA EPA Resources Board, 2009. Proposed Regulation 2 App. C1, 29)

Alternatives considered

Alternative 1: Using California Air Resources Board method for electricity and hydrogen light-duty EER. *Arguments in favor* — 1) Consistency with California Low Carbon Fuel Standards. 2) The EER new vehicles will be the California Air Resources Board’s EERs due to fuel economy requirements.

Alternative 2: Use California Air Resources Board (CARB) EER for CNG/LNG. *Arguments in favor* — 1) Consistency with California

Rationale for DEQ Proposal

DEQ staff propose to use EERs for Oregon based on California Air Resources Board research with two exceptions:

- Light duty gasoline vehicles. Because the EER of an electric vehicle today is 4.1 compared to a gasoline vehicle, 4.1 is the EER we will use today. But as light duty vehicles become more fuel efficient, the EER will decline to 3.1, and DEQ proposes to use that value in 2022.
- CNG/LNG heavy-duty. Oregon does not have as large a natural gas legacy vehicle fleet as CA does. New CNG/LNG heavy-duty vehicles are becoming more efficient.

DEQ also adjusts light-duty EERs to account for the fact that Oregon does not use reformulated gasoline and California does.
DEQ also added in a 2014 update to EERs based on EPA’s proposed heavy-duty fuel economy improvements. Light duty EERs will also be reviewed at that time.

Advisory committee input on this issue can be found in Appendix A.

VIII. Compliance Scenarios and Economic Analysis

1. Introduction

The Oregon low carbon fuel standards are designed so compliance can be achieved in a variety of ways; it does not mandate the use of any specific fuel type to achieve the ten percent reduction in carbon intensity by 2022. Each regulated party can choose the best fuel types to use given their particular circumstances and can also use low carbon fuel credits generated through the low carbon fuel standards program. Therefore, to assess program feasibility, it is helpful to develop and evaluate several different scenarios that reflect different potential mixes of fuel types that could be achieved over the next decade.

The basis of the compliance scenario approach is to identify which design factors are important enough to base decisions on and then bracket these parameters in an attempt to quantify the impact of each. This approach resulted in the advisory committee being able to compare eight different combinations of assumptions referred to as compliance scenarios, or ways compliance with the low carbon fuel standards can be achieved.

With the expertise of consultants and assistance from other state agencies, DEQ conducted a four-step analysis for its economic analysis. In order for the economic analysis to be meaningful, care must be taken in developing inputs. This section provides an overview of the technical analyses that will provide the inputs and the decisions that were made in the course of each step. Each of these steps is described in detail on the following pages (or for carbon intensities, in the last chapter).

1) Step 1: Conduct biomass assessment
2) Step 2: Conduct fuels assessment
3) Step 3: Calculate carbon intensities
4) Step 4: Develop compliance scenarios
5) Step 5: Conduct economic analysis

There are four critical data inputs necessary to complete a useful economic analysis. They are shown here in Figure 24 on page 146 and described in detail in the following sections.
2. **Biomass Assessment**

Biomass is defined as any organic matter, including woody biomass, agricultural crops, wood wastes and residues, plants, aquatic plants, grasses, residues, fibers, animal wastes, municipal wastes and other waste materials. For the purpose of estimating the potential availability of biomass for use as transportation fuel in Oregon, DEQ staff collected available information from existing studies on four different types of biomass, namely: wood, municipal solid waste, biogas and agricultural sources. DEQ did not conduct any original research on biomass availability. For detailed information on available estimates of biomass in Oregon suitable for use as a low carbon transportation fuel alternative, please refer to the Biomass Assessment and associated tables found in **Appendix I: Biomass Assessment**.

Several biofuels crops could be grown in Oregon on existing agricultural cropland, which are not currently grown in large quantities. In addition, there could be increased production of crops that are already grown in Oregon. There are also sources of biomass that have not been fully quantified for Oregon, including things such barley straw, mint slug, horse manure, culled fruits and vegetables, yellow grease (restaurant grease), brown grease (sewer and pipe grease that are trapped and collected), food processing waste, and cheese whey.

**Issues related to using biomass for transportation fuel production**

Much of the biomass that is considered a waste product, like sawdust or other mill residues, are low in price and are often the easiest biomass feedstock to access. As such, this waste stream has historically been utilized to a high degree in the production of other products (composite materials, particle/fiber board, animal bedding) or used to provide fuel for energy production (typically at a boiler to provide heat and power for the mill). Ultimately, the markets for these feedstocks will determine how and where they are used. Some of the currently available biomass...
could be used in future waste-to-energy projects. It is useful, however, to consider that Oregon is poised to make investments in facilities that will increase the utilization of available biomass.

Fuel generated from waste, such as forest residue, municipal solid waste, or agricultural residue will in general have lower carbon intensity than a fuel produced from a crop. This is because it is waste material, and the lifecycle analysis therefore does not include the production of the material, just the transport of the waste, conversion into fuel, distribution and use.

Advisory committee input on this issue can be found in Appendix A.

3. Fuels Assessment Discussion Paper

The Fuels Assessment discussion paper, which is included as in Appendix H: Fuels Assessment Discussion Paper, assesses the commercialization status of production technologies and the volume of fuel feedstocks likely to be available. DEQ consulted with other state agencies, fuel and feedstock producers, and other experts to compile this information, which was presented as a discussion paper at the April 15th advisory committee meeting for input, and used to develop several compliance scenarios. Although the input from the advisory committee was used in developing compliance scenarios, the Fuels Assessment Discussion Paper has not been changed to reflect input from the advisory committee. In addition, the Biomass Assessment gives some indication of how much fuel Oregon could produce from in-state feedstocks, although DEQ recognizes that the trend of importing either fuel, or in the case of ethanol, fuel feedstocks from out-of state might continue. Biomass availability studies in Oregon are summarized on in Appendix I: Oregon Biomass Assessment.

A. Fuels Assessment discussion paper

The low carbon fuels assessment discussion paper provided information to help the advisory committee and DEQ estimate volumes (bound high and low possible amounts) of alternative fuels used in Oregon between now and 2022. These estimates were discussed by the advisory committee and used in developing compliance scenarios, which in turn will be used in the low carbon fuel standards economic analysis.

The following three tables summarize Fuels Assessment findings for each fuel. For more details, please refer to each fuel assessment table:

Table 1: Summary Table for Alternative Fuels summarizes commercialization status and production information for alternative fuels
Table 2: Summary Table for Projected Alternative Fuel Use in Oregon in 2022 summarizes proposed low, moderate and high estimates of alternative fuels use in 2022.
Table 3: Summary Table for Alternative Fueled Vehicles in Oregon in 2022 summarizes proposed low, moderate and high estimates of alternative fueled vehicles in 2022.
These tables and the entire Fuels Assessment Discussion Paper can be found in Appendix H of this report and on the Oregon DEQ Low Carbon Fuels Standards web page at: http://www.deq.state.or.us/aq/committees/docs/apr2010/fuelsAssessmentDiscussion.pdf

Fuels Assessment Discussion Paper Content
The Fuels Assessment took the following factors into account in establishing the range of production and volumes used to bound the projected fuel volumes available in Oregon in the future:

- **Feedstock and Production Process.** For each of the fuels listed, the Assessment provides a brief description the feedstock used to make the fuel, production process or processes, and a listing of co-products generated from production. Co-products can displace other products currently on the market, thereby benefiting a fuel’s carbon intensity.

- **Commercialization Status of Fuel and Vehicles.** For each fuel type assessed, the commercialization status of the fuel is listed. Commercialization status includes information on whether the fuel is still in the early development stages and has essentially been produced in a laboratory only, whether it is in the initial stages of commercialization (for example, it has been produced at a pilot or demonstration scale), or whether it is fully commercialized and developed to the point at which it’s production and sale becomes economically feasible. For vehicles, the commercialization status is discussed.

- **Production.** For each fuel listed, the Assessment describes the current production or production capacity in Oregon, whether there is potential for more production in Oregon based on the feedstock available, and production volumes or capacity in the rest of the United States or the world, if applicable.

- **Use of Fuel for Transportation Purposes.** If information is available, the Assessment includes discussion of the current use of the fuel in Oregon, focusing on the volume used, the number of vehicles using the fuel, the existing infrastructure for the fuel, and any barriers to expansion or other special issues.

- **Summary of Known Trends.** This section covers available data on trends in the use of the fuel for transportation, the production of the fuel (if relevant), and the use, availability or production of alternative-fueled vehicles. Where available, information is provided that is specific to trends in Oregon or the United States. For some fuels, data was not collected until recently. For example, the U.S. Energy Information Administration did not start collecting data on CNG used as a transportation fuel until 2004. For most fuel, information is not yet available for 2008 or 2009, although there are some exceptions.

- **Preliminary Estimates of 2022 Use.** This section estimates future use, based on the trends in Oregon, the United States, or the world. DEQ has proposed a draft, preliminary estimate for low, moderate and high use in 2022 for some of the alternative fuels based on historic trends in fuel or vehicle use, regulatory requirements, studies, adoption rates in other areas, expert opinions, and methodologies used by others. DEQ intends to use the Fuels Assessment estimates of alternative fuel and vehicle use as inputs into the compliance scenario modeling.
In developing the draft scenarios, DEQ considered (based on advisory committee input) that alternative fuel use would increase under low carbon fuel standards above amounts required by existing regulations or predicted by historic increases. The following sources of information were assessed in generating estimates for future alternative fuels volumes in Oregon:

- Regulations applicable to an alternative transportation fuel or alternative-fueled vehicle, such as the federal Renewable Fuel Standard 2 requirement for biofuels or the Oregon Low Emission Vehicle Rule;
- Historic increases in alternative fuel use;
- Alternative fuel use trends in other countries, states, or areas that use large volumes of an alternative fuel or vehicles can help us identify feasible adoption rates for both light-duty passenger vehicles and medium/heavy-duty vehicle applications;
- Predictions of future use;
- Studies and expert evaluation; and
- Compliance scenario methodologies for low carbon fuel standards used by Washington, East Coast/Mid-Atlantic States, and California.

Advisory committee input on this issue can be found in Appendix A.

4. **Calculate Carbon Intensities**

For a detailed discussion on carbon intensities, see Section on Calculating Carbon Intensities for Oregon Transportation Fuels on page 122.

5. **Compliance Scenarios**

A compliance scenario combines information from the fuels assessments and the calculation of carbon intensities to estimate the volume of one or more low carbon fuels that would be needed to achieve the low carbon fuel standards. There are several purposes for developing compliance scenarios:

- The scenarios allow DEQ to assess whether the current production capacity of low carbon fuels in Oregon will likely be sufficient to support compliance with a low carbon fuel standards program.
- The scenarios allow DEQ to identify any gaps in alternative fuel availability that would need to be filled in order to have a feasible program. This allows DEQ to evaluate the low carbon fuel standards phase-in schedule in light of expected fuel availability and identify investment needs and economic development opportunities for Oregon to increase the availability of lower carbon alternatives fuels by 2022.
- The different compliance scenarios allow DEQ to evaluate the reasonable range of possible economic impacts associated with different compliance options.

Oregon’s contractor, TIAX LLC, with substantial input from the low carbon fuel advisory committee created a business-as-usual case that captures the future assuming no low carbon fuel standard to establish a base case with only known regulations incorporated. It assumed that Oregon receives its
proportional share of alternative fuels required by the federal Renewable Fuel Standard (RFS2) and that the Oregon Renewable Fuel Standard and Portland Renewable Fuel Standard regulations remain in place.

DEQ worked with the advisory committee to develop eight variations of compliance scenarios in order to compare the effects of several factors including: indirect land use change, in-state vs. out-of-state production of biofuels, price of crude, the need for advanced cellulosic technologies to develop, and the adoption rate of electric vehicles. TIAX then created the different fuel combinations that represent each compliance scenario. All scenarios were created to achieve a 10 percent reduction in carbon intensity by 2022.

**Scenario A – Cellulosic Biofuels with Indirect Land Use Change (Runs 1 + 6)**

Run 1 – Cellulosic Ethanol with indirect land use change (Produced In-State)
- In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of in-state cellulosic ethanol.
- If more ethanol is needed to reach total RFS2 proportional share volumes, it comes from Midwest corn ethanol.

Run 6 – Cellulosic diesel with indirect land use change (Produced In-State)
- Compliance achieved through the use of new in-state cellulosic diesel and new waste oil biodiesel capacity

**Scenario B – Mixed Biofuels with Indirect Land Use Change (Runs 2 + 7)**

Run 2 – Mixed Ethanol with indirect land use change
- In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of sugarcane ethanol, lower carbon intensity Midwest corn ethanol, and cellulosic ethanol
- So much ethanol was required here that the blend wall had to be increased to E12 (12 percent ethanol blended with gasoline) in 2017 and E15 (15 percent ethanol blended with gasoline) in 2020

Run 7 – Conventional biodiesel with indirect land use change
- Compliance achieved through:
  - Moderate amounts of in-state cellulosic diesel production
  - Out of state grown and produced camelina renewable diesel
  - New In-state waste oil biodiesel capacity
  - Existing in-state canola biodiesel
  - New out-of-state canola biodiesel production from Oregon grown canola

**Scenario C – Mixed Biofuels without Indirect Land Use Change (Runs 3 + 8)**

Run 3 – Mixed Ethanol without indirect land use change
- In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of sugarcane ethanol, lower carbon intensity Midwest corn ethanol, and cellulosic ethanol
- For comparison with Run 2 in Scenario B, we increased the blend wall to E12 in 2017 and E15 in 2020

Run 8 – Conventional Biodiesel without indirect land use change
- Compliance achieved through
- Existing canola biodiesel
- Existing waste oil biodiesel
- Midwest soybean biodiesel

**Scenario D – Electricity, Natural Gas and Cellulosic Biofuels with Indirect Land Use Change (Runs 4 + 9)**

Run 4 – High Electric Vehicles with Cellulosic Ethanol with indirect land use change (Produced In-State)
- In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of Electric Vehicles and Plug-In Hybrid Electric Vehicles plus in-state cellulosic ethanol
- Similar to Run 1 except more plug in vehicles are included, so less ethanol is required

Run 9 – max natural gas vehicles and cellulosic diesel with indirect land use change
- Similar to 6, but more natural gas vehicles are included so less biofuels are required

**Scenario E – One Pool**

- Gasoline pool reductions achieved mainly through the use of in state produced cellulosic ethanol (on top of existing Northwest corn ethanol and waste berry ethanol production).
- Plug-in vehicle populations double the BAU
- Diesel pool reductions achieved mainly through the use of in state produced cellulosic diesel, new waste oil biodiesel capacity and imported camelina renewable diesel.
- Light-duty diesel populations increase, natural gas populations increase

**Scenario F – Mixed Biofuels without Indirect Land Use Change, high oil prices (Runs 3H+8H)**

- Similar mix of fuels as Scenario C, but with higher oil prices (A new BAU was run as well)

**Scenario G – Mixed Biofuels without Indirect Land Use Change, low oil prices (Runs 3L+8L)**

- Similar mix of fuels as Scenario C, but with lower oil prices (A new BAU was run as well)

**Scenario H – Cellulosic Biofuels with Indirect Land Use Change, Out-of-State (Runs1H+6H)**

Run 1H – Cellulosic Ethanol with indirect land use change (Produced Out-of-State)
- In addition to Northwest corn ethanol and waste berry ethanol, compliance with standards achieved through use of out-of-state cellulosic ethanol.
- If more ethanol is needed to reach total RFS2 proportional share volumes, it comes from Midwest corn.

Run 6H – Cellulosic biodiesel with indirect land use change (Produced Out-of-State)
- Compliance achieved through the use of out-of-state cellulosic diesel and new in-state waste oil biodiesel capacity, existing in-state canola biodiesel.

**Alternatives considered**

DEQ considered many factors that provided the basis to many of the compliance scenario assumptions. A summary of the major factors considered include:

- **Factor 1**: End point of the low carbon fuel standards. Instead of using 2022 as the end point of the low carbon fuel standards, end points of 2020 or 2024 were considered. 2020 would align with California’s program. Since it would be at least 2012 for rulemaking to be complete, the program
would be less than 10 years. Therefore, regulated parties would have an accelerated timeframe to comply with the 10 percent reduction mandate. 2024 would align with Washington’s program (although subsequent recommendations from Washington have a 2023 end point year). This would result in the program’s reporting-only year being 2014 and the first compliance year being 2015. This delay in implementation would severely impede development of the infrastructure needed to support the low carbon fuel standards. It would also complicate how DEQ could implement this program in light of the 2015 sunset date in the statute.

Factor 2: Indirect Land Use Change. Instead of choosing to adjust the carbon intensity of biofuels with California Air Resources Board’s indirect land use change number, using a different indirect land use change number. EPA has indirect land use change numbers they used in the RFS2 program. Purdue University also has a new number for corn ethanol. There is no consensus whether one number is better or more accurate than another. The use of the California Air Resources Board number is not an acknowledgement of its accuracy or acceptance, but merely to provide an upper bound for analysis purposes. Once analysis provides some information on the significance of its effect, then the advisory committee members recommended what indirect land use change number to use for compliance purposes.

Factor 3: Oregon’s share of RFS2 biofuels volumes. RFS2 requires a minimum volume of biofuels to be produced nationwide, but does not specify where these volumes are used. In order to estimate the amount of alternative fuels Oregon should expect to receive, assumptions needed to be made. The advisory committee recommended by consensus that the compliance scenarios assume that Oregon would receive its proportional share (by percentage of its fuel used compared to the entire country) of RFS2 biofuels.

Factor 4: Blend wall. In order to use all of the ethanol expected from Oregon’s proportional share of RFS2, assumptions had to be about whether the current blend of E10 or a higher blend of gasoline is the assumed base case statewide, also known as the blend wall. A E15 blend wall assumes that more ethanol would be used in E15 gasoline, less used in E85 (the only alternative), less vehicle miles traveled by flex fuel cars (those capable of burning E85), compared to the E10 blend wall. An E15 blend wall also leads to higher gasoline distribution infrastructure costs but lower vehicle infrastructure costs. The State of Washington’s low carbon fuel standards analysis assumed that a statewide ethanol blend of 15 percent ethanol would be in place in the future. The advisory committee recommended by consensus that E10 would be the blend wall.

Factor 5: In-state production of alternative fuels. A basic assumption of all the scenarios is that the current in-state production of alternative fuels remains the same in the future.

Advisory committee input on this issue can be found in Appendix A.

6. Economic Analysis

DEQ hired a national expert in economic assessment (Jack Faucett Associates) to conduct an economic impact analysis of implementing a Low Carbon Fuel Standards Program. The economic analysis report (See Appendix D: Economic Analysis Report) was prepared by Jack Faucett Associates (JFA). In addition, JFA also completed a study attached as Appendix E: Comparable Economic Studies in Other States Memorandum. The DEQ and consultant, TIAX LLC., developed the Low Carbon Fuel Standard compliance scenarios. TIAX estimated the direct impacts of the scenarios by using the Argonne National
Laboratory VISION model and JFA converted the VISION outputs to inputs to the REMI PI+ macroeconomic model for the State of Oregon. The REMI model runs were conducted by REMI Northwest. The inputs and outputs of the REMI model were reviewed by Adam Rose, Ph.D. and Dan Wei, Ph.D. from the University of Southern California. DEQ staff provided project data and insightful reviews of model runs and reports.

A. How were the Economic Impacts Analyzed?

The economic analysis of a potential Low Carbon Fuel Standard in Oregon is focused on the development and evaluation of potential impacts from a wide range of fuels that could be used in the future to comply with the low carbon fuel standard. The purpose of the standard is to reduce carbon intensity of transportation fuel (including off-road equipment and vehicles) used from motor vehicle use in the state. This will be accomplished by altering the fuel supply mix from mostly petroleum products to a mix still dominated by petroleum products, but containing a greater portion of lower carbon alternatives such as ethanol, bio-diesel, compressed natural gas and electricity. The different compliance scenarios reflect the uncertainty of market response – responses may focus on any one of a variety of fuels, those fuels may come from in-state, out-of-state or foreign feedstocks, and they may be refined locally or out of state. A description of the compliance scenarios can be found on page 149 and in Appendix F: Compliance Scenario Description.

These compliance scenario options were analyzed, with the use of several nationally accepted economic models, to determine how industry and households would alter their demand for vehicles and fuel from the initiation of the standard through 2022. This exercise included existing federal and state regulations governing the production of biofuels, biofuels blending requirements, and car efficiency standards. This scenario testing shows that a low carbon fuels standard in Oregon is both feasible and economically beneficial. Changes in expenditures for petroleum and alternative fuels and the vehicles that use them were estimated along with the origin (Oregon produced or imports) of these fuels. These changes in expenditures led to changes in future employment, income, output and state product. The results were reported to the Advisory Committee for review and comment.

The Economic Analysis is included as Appendix D: Economic Analysis.

B. Economic Analysis Results

The macroeconomic modeling analysis produced estimates of overall economic impacts in the state, as well as specific impacts to approximately 70 different sectors of the economy, for all eight different compliance scenarios. All scenarios except the last scenario, which assumed all production to come from out of state, showed significant positive impacts.

To achieve compliance, significant investment in infrastructure and fuel production capacity results in an influx of economic activity. Employment, income and gross state product all grow as a result. The scenario projection generating the largest positive impact anticipated significant investment in new infrastructure for electricity and compressed natural gas. The scenario projecting the smallest impact anticipated all new low-carbon fuels being produced out of state.
The most significant impact from all compliance scenarios is generated by the investment in new production capacity and infrastructure. The consumer is projected to face some change in fuel expenditure (which is sometimes and increase and sometimes a decrease, depending on the scenario), but any such change is dwarfed in scale by the amount of economic activity generated by investment in new plants, new charging stations and new pumping equipment.

**Figure 25: Impact on Oregon’s Employment**

All scenarios that rely on liquid fuels from in-state supply demonstrate similar macro impacts. Positive economic impacts in Oregon stem from the importation of less petroleum fuel and its replacement with Oregon produced products, as well as from the investment in new infrastructure. Sensitivity analyses found that changes in fuel price projections had little effect on the broader economic impacts. Analyses also showed that changes in the assessment of emissions penalties for indirect land-use change (ILUC) had little effect on the broader projections of economic impacts.

In addition, all eight scenarios considered resulted in projections that consumers would face lower costs at the pump as a result of a low-carbon fuel standard. Please see Figure 26 on page 155 for fuel spending results. These impacts were moderate for biofuels, which are projected to cost almost as much as gas and diesel. They were significant, however, when electricity and natural gas (two fuels which cost much less than petroleum for the same amount of energy) were added to the mix.
Advisory committee input on this issue can be found in Appendix A.

C. Cost Effectiveness

One of many questions to consider in adopting Oregon’s low carbon fuel standards is whether the program would be “cost effective”\(^{vi}\). The economic analysis discussed in Section XX of this report shows that the overall effect of an Oregon low carbon fuel standards program would be cost effective. The analysis shows that Oregon low carbon fuel standards can promote new job growth, increase money retained in Oregon (i.e. less local money lost to fuel exports means more money retained for use directly in Oregon’s economy), and have other positive net benefits to the state’s economy. There is no one specific metric (or approach) for evaluating the “cost effectiveness” of low carbon fuel standards, but DEQ’s “economic impact assessment” reflected cost-effectiveness through the assessment of net cost of compliance across all compliance scenarios and the results indicate a net economic benefit to the state overall.

Providers of conventional petroleum fuels regulated under low carbon fuel standards would likely experience some negative compliance costs under a low carbon fuel standards program, as well as potentially some loss in revenue growth as less petroleum fuel is consumed in favor of alternatives.

\(^{vi}\) HB2186 Section6 (3) In adopting rules under this section, the Environmental Quality Commission shall evaluate: (a) Safety, feasibility, net reduction of greenhouse gas emissions and cost-effectiveness;
However, many regulated fuel companies are diversifying their own fuel resource portfolio and may also profit from increased sales of biofuels. Costs and revenues are also driven by foreign demand for petroleum, global supply, and many other external economic conditions. The nature of the petroleum retail market is very complex, and while there would be costs associated with low carbon fuel standards compliance, there could also be other mitigating factors that reduce the net cost of compliance to all regulated entities. It is not clear in the early stages, whether a low carbon fuel standards program would be cost effective for petroleum fuel providers. Other sectors, such as biofuels production, natural gas, or those involved in electric vehicles are expected to see positive economic benefits. For these sectors, adoption of the low carbon fuel standards is cost effective. Section X and Appendix Y of the report provide more information on the expected overall economic impacts to Oregon’s economy as a result of low carbon fuel standards as well as estimates of how 70 economic sectors would likely be affected.

HB2186 contains a sunset provision that would effectively end Oregon’s low carbon fuel standards program in 2015, unless that sunset is removed by the legislature. Section X of this report discusses the effect of the sunset on the low carbon fuel standards program. DEQ’s low carbon fuel standards advisory committee agreed that the existence of the sunset could seriously undermine the early investments (financial and material) needed to expand Oregon’s biofuels production capacity. These locally produced biofuels can play a significant role in helping regulated parties comply with the low carbon fuel standards, and create fuel resource stability and affordability... The economic benefits from in-state fuels production help make Oregon’s low carbon fuel standards cost effective and provide further economic opportunities through the development of a low-carbon economy.
IX. Potential Impacts to Public Health and the Environment

The distribution and combustion of transportation fuels is one of the largest contributors of human-caused air pollution. This chapter provides an overview of the pollutants DEQ regulates and the health effects\(^\text{vii}\) that can occur from being exposed to them. This section will also explore how low carbon fuel standards could affect air quality in Oregon.

1. **Criteria Pollutants**

   **Fine Particulate Matter**: Fine particulate matter (PM\(_{2.5}\)) consists of solid particles or liquid droplets that are less than 2.5 micrometers in diameter.

   **Sources** – Residential wood stoves and fireplaces, industrial boilers, field burning, diesel combustion, agricultural tilling, road dust, and other combustion processes emit fine particulate matter.

   **National Ambient Air Quality Standard** – 35 µg/m\(^3\) (24-hr average); 15 µg/m\(^3\) (annual average)

   **Areas not Meeting the Standard** – Klamath Falls, Lakeview, Springfield

   **Health Effects** – In general, fine particulate matter causes three kinds of health problems:
   - The particles may be inherently toxic because of their chemistry
   - The particles may mechanically damage the respiratory system
   - The particles may be carriers for other toxic substances

   Exposure to high concentrations of particulate matter increase hospital admissions for respiratory infections, heart disease, bronchitis, asthma, emphysema, and similar cardiovascular and pulmonary diseases.

   **Carbon Monoxide**: Carbon monoxide (CO) is a colorless, odorless gas.

   **Sources** - Incomplete combustion of carbon-based fuels, primarily gasoline-powered motor vehicles, wood stoves, and outdoor burning.

   **National Ambient Air Quality Standard** – 35 ppm (1-hr average); 9.5 ppm (8-hr average)

   **Areas not Meeting the Standard** – None

   **Health Effects** – In the body, CO binds tightly to hemoglobin, the red pigment in blood, which transports oxygen from the lungs to the rest of the body. Once hemoglobin is bound to CO, it can no longer carry oxygen (O\(_2\)). High concentrations of CO strongly impair the functions of O\(_2\)-dependent tissues, including the brain, heart, and muscles. Prolonged exposure to low

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\(^{vii}\) All health effects presented in this section are derived from the Agency for Toxic Substances & Disease Registry at: [www.atsdr.cdc.gov/substances/indexAZ.asp](http://www.atsdr.cdc.gov/substances/indexAZ.asp).
levels of CO aggravates existing conditions in people with heart disease or circulatory disorders.

**Nitrogen Oxides** - Nitrogen dioxide (NO\(_2\)) is a reddish-brown gas that is a primary component in the formation of ground-level ozone or smog when it reacts with volatile organic compounds in a photochemical reaction. It also combines with moisture in the air to form nitric acid, which causes corrosion of metal surfaces and contributes to acid rain. In addition, NO\(_2\) absorbs visible light and reduces visibility. Nitric oxide (NO) is also produced during the combustion process, but once in the atmosphere, NO is rapidly oxidized to form NO\(_2\).

**Sources** - Fuel combustion in motor vehicles and utility and industrial boilers.

**National Ambient Air Quality Standard** – 0.053 ppm (annual average)

**Areas not Meeting the Standard** – None

**Health Effects** – NO\(_2\) is a lung irritant and may be related to chronic pulmonary fibrosis.

**Sulfur Dioxide** - Sulfur dioxide (SO\(_2\)) is a colorless, pungent gas. It combines with moisture in the air to form sulfuric acid which causes corrosion of metal surfaces and other building materials. In addition, sulfuric acid and sulfate particles formed in the atmosphere from SO\(_2\) can contribute to regional haze and acid rain.

**Sources** - The major source of SO\(_2\) nationwide is combustion of high sulfur coal; but in Oregon where burning of high sulfur coal is not allowed, diesel, heating oil, and low sulfur coal are the major sources.

**National Ambient Air Quality Standard** – 0.14 ppm (24-hr average); 0.03 ppm (annual average)

**Areas not Meeting the Standard** – None

**Health Effects** – SO\(_2\) acts as a lung and eye irritant. When SO\(_2\) is inhaled, it causes bronchial constriction, which results in breathing difficulty and increased pulse and respiratory rate. People with respiratory diseases like asthma, bronchitis, or emphysema are particularly susceptible to the effects of SO\(_2\). When particles capable of oxidizing sulfur dioxide to sulfuric acid are present, the irritant response increases in magnitude by two to three times. When sulfuric acid is inhaled, mucous production increases. This reduces the respiratory system's ability to remove particulate matter, and can lead to more severe respiratory infections, such as pneumonia. Chronic exposure to SO\(_2\) can lead to coughing, shortness of breath, fatigue, and bronchitis.

**Volatile Organic Compounds** - Volatile organic compounds, commonly referred to as “VOCs”, are a large family of compounds made up primarily of hydrogen and carbon. These compounds are instrumental in the complex series of reactions leading to the formation of ground-level ozone and smog, where they combine with nitrogen oxides in high heat and sunlight. Many volatile organic compounds are also air toxics (and are described individually below). The EPA and DEQ do not have an ambient standard for volatile organic compounds, but they are still regulated because of
their contribution to ozone formation and because many are air toxics. Regulations include capping
the amount of these compounds in coatings and limits in industrial permits.

Sources - Motor vehicles, fuel evaporation, coatings and inks, and combustion processes.

**Ground-Level Ozone or Smog** - Ozone (O\(_3\)) is a pungent, toxic, highly reactive form of oxygen.
Ozone is not emitted directly into the air. It is formed through a series of chemical reactions
between VOCs, NOx, and oxygen during hot weather. Ozone can affect a variety of materials,
resulting in fading of paint and fiber, and accelerated aging and cracking of synthetic rubbers and
similar materials. Reductions in growth and crop yield have been attributed to ozone. To control
ozone pollution, it is necessary to control emissions of VOCs and NOx.

National Ambient Air Quality Standard\(^{viii}\) – 0.075 ppm (8-hr average)

Areas not Meeting the Standard – None

Health Effects - Long-term exposure to ozone causes significant breathing problems, such
as loss of lung capacity and increased severity of both childhood and adult asthma. Ozone causes irritation of the nose, throat, and lungs. Exposure to
ozone can cause increased airway resistance and decreased efficiency of
the respiratory system. In individuals involved in strenuous physical
activity and in people with pre-existing respiratory disease, ozone can
cause sore throats, chest pains, coughing, and headaches.

2. **Air Toxics**

**Acetaldehyde** - Acetaldehyde (CH\(_3\)CHO) is a product of incomplete combustion. It is a colorless
liquid that is flammable and has a fruity and pleasant odor at dilute concentrations.

Sources - incomplete wood combustion in fireplaces and woodstoves, coffee roasting,
burning of tobacco, vehicle exhaust fumes, and coal refining and waste
processing

Ambient Benchmark Concentration – 0.45 µg/m\(^3\) (annual)

Oregon Annual Average over the Ambient Benchmark Concentration? - Yes

Health Effects – Acute (short-term) exposure to acetaldehyde results in effects including
irritation of the eyes, skin, and respiratory tract. Symptoms of chronic
(long-term) intoxication of acetaldehyde resemble those of alcoholism.
Acetaldehyde is considered by EPA to be a probable human carcinogen
(Group B2) based on inadequate human cancer studies and animal studies
that have shown nasal tumors in rats and laryngeal tumors in hamsters.

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\(^{viii}\) EPA is expected to finalize the reconsideration of the 2008 8-hr ozone standard by July, 2011. Multiple
locations in Oregon could fail to be in attainment with the standard depending on what it is. Medford has the
highest risk, followed by Portland, Salem, and Hermiston.
1,3-Butadiene – 1,3-Butadiene ($C_4H_6$) is a colorless gas with a mild gasoline-like odor. It is used to make synthetic rubber and plastics including acrylics and is a component of gasoline.

Sources - Vehicle exhaust, waste incineration, wood fires, or cigarette smoke.

Ambient Benchmark Concentration – 0.03 µg/m$^3$ (annual)

Oregon Annual Average over the Ambient Benchmark Concentration? - Yes

Health Effects – Acute (short-term) exposure to 1,3-butadiene causes nausea, dry mouth and nose, headache, and decreased blood pressure and pulse rate. Chronic (long-term) symptoms include increased risk of cancers of the stomach, blood, and lymphatic system. 1,3-butadiene is considered by EPA to be a carcinogen.

Benzene - Benzene ($C_6H_6$) is a colorless liquid with a sweet odor. It evaporates into the air very quickly and dissolves slightly in water. It is highly flammable and is formed from both natural processes and human activities.

Sources - Benzene ranks in the top 20 chemicals for production volume. It is used to make plastics, resins, nylon and other synthetic fibers, some types of rubbers, lubricants, dyes, detergents, drugs, and pesticides. Natural sources of benzene include emissions from volcanoes and forest fires. Benzene is also a natural part of crude oil, gasoline, and cigarette smoke.

Ambient Benchmark Concentration – 0.13 µg/m$^3$ (annual)

Oregon Annual Average over the Ambient Benchmark Concentration? - Yes

Health Effects – Acute (short-term) exposure to very high levels of benzene can result in death, while high levels can cause drowsiness, dizziness, rapid heart rate, headaches, tremors, confusion, and unconsciousness. Chronic (long-term) exposure to low levels of benzene causes harmful effects on the bone marrow, red blood cells, the immune system, and excessive bleeding. Chronic exposure to high levels of benzene can cause leukemia, particularly acute myelogenous leukemia, often referred to as AML, a cancer of the blood-forming organs. EPA has determined that benzene is carcinogenic to humans.

Diesel Particulate Matter – Diesel particulate matter is emitted from diesel-powered engines. Diesel particulate matter is defined as fine particulate matter ($PM_{2.5}$) and carries all of the health effects described for $PM_{2.5}$. It also causes visibility impairment and regional haze.

Sources – Diesel exhaust is emitted from a broad range of diesel engines; the on-road diesel engines of trucks, buses and cars and the off-road diesel engines that include locomotives, marine vessels and heavy duty equipment.

Ambient Benchmark Concentration – 0.1 µg/m$^3$ (annual)

Oregon Annual Average over the Ambient Benchmark Concentration? – Yes

Health Effects – Acute (short-term) exposure to diesel exhaust may cause irritation to the eyes, nose, throat and lungs, some neurological effects such as
lightheadedness, or exacerbate asthma. Chronic (long-term) exposure has shown lung inflammation, cellular changes in the lungs, and immunological effects. Based upon human and laboratory studies, there is considerable evidence that diesel exhaust is a likely carcinogen. EPA has not determined the toxicity of diesel PM based on its carcinogenicity.

**Formaldehyde** - Formaldehyde (CH$_2$O) is a colorless, flammable gas that has a distinct, pungent smell. It is used in the production of fertilizer, paper, plywood, urea-formaldehyde resins, as a preservative in some foods, and in many products used around the house, such as antiseptics, medicines, and cosmetics.

**Sources** - Cigarettes and other tobacco products, gas cookers, and open fireplaces are sources of formaldehyde exposure. Formaldehyde is given off as a gas from the manufactured wood products used in new construction.

**Ambient Benchmark Concentration** – 3 µg/m$^3$ (annual)$^ix$

**Oregon Annual Average over the Ambient Benchmark Concentration?** – No

**Health Effects** – Low levels of formaldehyde can cause irritation of the eyes, nose, throat, and skin. People with asthma may be more sensitive to the effects of inhaled formaldehyde. It is likely that EPA will make a determination soon about the carcinogenicity of formaldehyde, but none currently exist.

Implementation of low carbon fuel standards in Oregon will lead to increased volumes of alternative fuels used as transportation fuels. Ethanol and biodiesel are the fuels that will replace petroleum gasoline and diesel as the traditional transportation fuels in the most significant quantities. While these alternative fuels may make sensible strategies for carbon reduction, there are other unintended consequences that have negative impacts on Oregon’s air quality.

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$^ix$ 3 µg/m$^3$ is the current Oregon Ambient Benchmark Concentration. EPA used a preliminary toxicity value of 0.08 µg/m$^3$ in the 2005 National Air Toxics Assessment to determine risk. Oregon’s annual average exceeds this value. EPA is expected to issue a finalized value in 2011 and then Oregon will decide whether to revise the ambient benchmark concentration.
3. **Effect of Burning more Ethanol**

Even before governments started mandating increased use of ethanol in gasoline blends as a climate change strategy, ethanol was used as an oxygenate to increase the efficiency of combustion and reduce carbon monoxide emissions. Co-benefits of this strategy were reduced emissions of particulate matter, sulfur dioxide, and unburned hydrocarbons. However, ethanol burns hotter than conventional gasoline, which in turn increases NOx emissions. In addition, the vapor pressure of gasoline-ethanol blends between 2 percent and 10 percent lead to increases in evaporative VOC emissions. The vapor pressure decreases in higher blends and so do VOC emissions.

The formula that leads to ground-level ozone formation varies by geography, meteorology, and emissions. Areas are typically categorized as either VOC-limited or NOx-limited to describe which type of emissions is the driver of ozone formation. Analysis of data from the Portland and Medford areas has determined that they are VOC-limited for ozone. That means that increases in VOC will cause more ozone formation than increases in NOx. Therefore, anticipated increases in NOx emissions from burning more ethanol should not lead to a significant increase on ozone formation.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>PM</th>
<th>CO</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>Ozone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethanol Blends*</td>
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<td>↓</td>
<td>↓</td>
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*(B.E.S.T. website 2008, "Review of Fuel Ethanol Impacts on Local Air Quality", 30*)

In the atmosphere, ethanol oxidizes into aldehydes, most significantly acetaldehyde and formaldehyde. Annual averages for the entire state and each of the 36 Oregon counties exceed the ambient benchmark concentrations for each of these air toxics. The use of more ethanol will increase emissions of acetaldehyde and formaldehyde, while emissions of other air toxics including benzene, 1,3-butadiene, PAHs, toluene, and xylene emissions will all decrease.

Federal vehicle fuel economy standards will reduce emissions of these air toxics in the future. Statewide efforts to adopt transportation and land use plans to reduce the amount of driving will further reductions. Lastly, local efforts to partner with communities to reduce air toxics that are over the benchmarks will also help lower the risk of exposure of individuals to these pollutants.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Acetaldehyde</th>
<th>Benzene</th>
<th>1,3-Butadiene</th>
<th>Formaldehyde</th>
<th>PAHs</th>
<th>Toluene</th>
<th>Xylene</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethanol Blends*</td>
<td>↑</td>
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4. **Effect from Burning more Biodiesel**

Biodiesel has become an increasingly attractive climate change strategy because it not only reduces direct CO\textsubscript{2} emissions from engines but also the diesel particulate matter which has a significant effect on climate change (600 - 900 times that of CO\textsubscript{2}). As part of the latter, both the mass and toxicity of diesel particulate matter is reduced with the replacement of biodiesel for petroleum diesel. Emissions of particulate matter, carbon monoxide, volatile organic compounds, and sulfur dioxide are all reduced. Some studies suggest that the higher oxygen content or the higher
Combustion temperatures of biodiesel produce an increase in nitrogen oxide emissions; but new
engine technologies have made adjustments to negate this effect. In addition, studies indicate that
the risk from exposure to a variety of air toxics (benzene, 1,3-butadiene, acetaldehyde,
formaldehyde, diesel particulate matter) decreases when biodiesel is blended with petroleum diesel.
Strategies to reduce diesel PM and PAHs will be needed in the future as DEQ continues its efforts
to meet the statewide benchmarks.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>PM</th>
<th>CO</th>
<th>NOx</th>
<th>VOC</th>
<th>Ozone</th>
<th>SO2</th>
<th>PAHs</th>
<th>Total Risk from Air Toxics</th>
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<tr>
<td>Biodiesel Blends**</td>
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<td>↓</td>
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**(U.S. DOE website 2003, "Impact of Biodiesel Fuels on Air Quality and Human Health", 31)

5. **Electricity Produced in Oregon**
Using electricity as a transportation fuel is a very effective strategy to reduce greenhouse gases but
considerations should be made for how that electricity is produced. The current profile of Oregon’s
electricity production is outlined in **Appendix B: Lifecycle Analysis**, but it is important to
remember that the renewable portfolio standard will require the carbon footprint of that profile to
be significantly reduced in the future. It is easy to presume that the future mix of Oregon’s
electricity will be produced from cleaner energy sources with respect to criteria pollutants and air
toxics.

6. **Other Environmental Impacts**
As raised in the section on **Indirect Land Use Changes and Other Indirect Effects** on page 135,
there are many unintended consequences related to establishing a low carbon fuel standard. The
inclusion of an indirect land use change will address carbon emissions as a result of changes in land
used to produce low carbon fuels, but there are a myriad of additional non-carbon effects that could
be considered.

**Water Quality & Quantity**: Significant increases in agricultural activities to meet the demand for
biomass-based fuels raise significant issues regarding the contamination of both surface and ground
water quality. Among them is the increased use of chemicals to maintain and increase crop yield
and increased cultivation activities that will increase runoff and soil erosion. More water may be
needed for irrigation.

The exploration of gas reserves uses the practice of “fracking” to create fractures in rocks to
increase the output of a well. Chemicals are commonly injected to accelerate this process and will
contaminate nearby groundwater if surveys are not accurate. Many drinking water supplies are
being contaminated this way. Another example is in the extraction of bitumen from the Canadian
oil sands reserves, which takes large quantities of water to steam the crude from the sands.

**Food versus Fuel**: Many low carbon fuels are being made from traditional food crops. The
feedstock of first generation ethanol is corn and sugar cane while the feedstock of first generation
biodiesel is soybean. Many believe that increased demand for low carbon fuels will result in higher
prices for food. Current research indicates that improvements in crop yield and the production of
co-products used as animal feed will negate this effect. Many also believe that these short-term
improvements will not be able to keep up with the continuing demand for low carbon fuels in the future.

**Ecological Effects:** Depending on where land use changes are occurring, there could be significant loss of habitat leading to the elimination or displacement of native species. The risk of severe losses due to wild fires will increase as human activity reaches farther into previously undisturbed terrain. If genetically modified crops replace native ones, there is a risk of unintended genetic mutations occurring nearby. Increased pesticide use could also lead to more water pollution.

At this time, no science exists to quantify these non-carbon effects such that it can be incorporated into a low carbon fuel standard. However, the science is continuing to evolve and DEQ will review its progress during future low carbon fuel standards program reviews in 2014 and 2016.

7. **Net Reduction in Greenhouse Gas Emissions**

House Bill 2186 requires the Environmental Quality Commission to consider net reductions in greenhouse gas emissions. DEQ calculated potential future greenhouse gas reductions with low carbon fuel standards in 2022 for two of the eight compliance scenarios. Scenario A achieved 2.285 million metric tons of carbon dioxide equivalent greenhouse gas pollution reductions. The one pool scenario achieved 2.189 million metric tons of carbon dioxide equivalent greenhouse gas pollution reductions.

*Advisory committee input on this issue can be found in Appendix A.*
X. Annotated Version of House Bill 2186, Sections 6-9

House Bill 2186 is a statute passed by the 2009 Oregon legislature, authorizing several greenhouse gas reduction strategies. Sections 6-9 of the bill authorize the Environmental Quality Commission to adopt rules for low carbon fuel standards. Below are sections 6-9 of the Bill. The full text of House Bill 2186 is available at the Oregon Legislative Website. Copies of enrolled bills are those that have passed both houses and have been signed by the Governor.

www.leg.state.or.us/09reg/measpdf/hb2100.dir/hb2186.en.pdf

SECTION 6

Definitions
(1) As used in this section:
   (a) “Greenhouse gas” has the meaning given that term in ORS 468A.210.
   (b) “Low carbon fuel standards” means standards for the reduction of greenhouse gas emissions, on average, per unit of fuel energy.
   (c) “Motor vehicle” has the meaning given that term in ORS 801.360.

Authority to adopt low carbon fuel standard rules:
(2) (a) The Environmental Quality Commission may adopt by rule low carbon fuel standards for gasoline, diesel and fuels used as substitutes for gasoline or diesel.
(b) The commission may adopt the following related to the standards, including but not limited to:

Schedule for implementation:
(A) A schedule to phase in implementation of the standards in a manner that reduces the average amount of greenhouse gas emissions per unit of fuel energy of the fuels by 10 percent below 2010 levels by the year 2020;

Lifecycle analysis to determine carbon intensity numbers for each fuel:
(B) Standards for greenhouse gas emissions attributable to the fuels throughout their lifecycles, including but not limited to emissions from the production, storage, transportation and combustion of the fuels and from changes in land use associated with the fuels;

Scope of fuels covered:
(C) Provisions allowing the use of all types of low carbon fuels to meet the low carbon fuel standards, including but not limited to biofuels, biogas, compressed natural gas, gasoline, diesel, hydrogen and electricity;

Deferrals for adequate fuel supply:
(D) Standards for the issuance of deferrals, established with adequate lead time, as necessary to ensure adequate fuel supplies;

Exemption threshold:

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* The Environmental Quality Commission is a five-member citizen panel appointed by the governor to four-year terms, serving as the Oregon Department of Environmental Quality’s (DEQ) policy and rulemaking board.
(E) Exemptions for liquefied petroleum gas and other alternative fuels that are used in volumes below thresholds established by the commission;

**Fuel quality:**
(F) Standards, specifications, testing requirements and other measures as needed to ensure the quality of fuels produced in accordance with the low carbon fuel standards, including but not limited to the requirements of ORS 646.910 to 646.923 and administrative rules adopted by the State Department of Agriculture for motor fuel quality; and

**Adjustments to carbon intensity numbers to account for drive train efficiency (efficiency of the motor):**
(G) Adjustments to the amounts of greenhouse gas emissions per unit of fuel energy assigned to fuels for combustion and drive train efficiency.

**Requirement to consider standards in other states:**
(c) Before adopting standards under this section, the commission shall consider the low carbon fuel standards of other states, including but not limited to Washington, for the purpose of determining schedules and goals for the reduction of the average amount of greenhouse gas emissions per unit of fuel energy and the default values for these reductions for applicable fuels.

**Consumer Cost Safety Net to ensure price of gasoline or diesel remains competitive:**
(d) The commission shall provide exemptions and deferrals as necessary to mitigate the costs of complying with the low carbon fuel standards upon a finding by the commission that the 12-month rolling weighted average price of gasoline or diesel in Oregon is not competitive with the 12-month rolling weighted average price in the PADD 5 region.

**A wide variety of requirements:**
(3) In adopting rules under this section, the Environmental Quality Commission shall evaluate:
   (a) Safety, feasibility, net reduction of greenhouse gas emissions and cost-effectiveness;
   (b) Potential adverse impacts to public health and the environment, including but not limited to air quality, water quality and the generation and disposal of waste in this state;
   (c) Flexible implementation approaches to minimize compliance costs; and
   (d) Technical and economic studies of comparable greenhouse gas emissions reduction measures implemented in other states and any other studies as determined by the commission.

**Exemption for certain vehicles:**
(4) The provisions of this section do not apply to:
   (a) Motor vehicles registered as farm vehicles under the provisions of ORS 805.300.
   (b) Farm tractors, as defined in ORS 801.265.
   (c) Implements of husbandry, as defined in ORS 801.310.
   (d) Motor trucks, as defined in ORS 801.355, used primarily to transport logs.

**SECTION 7**
**Adoption by Environmental Quality Commission and date rules become operative:**
(1) Except as provided in subsection (2) of this section, section 6 of this 2009 Act becomes operative on July 1, 2011.
(2) The Environmental Quality Commission may adopt rules before the operative date specified in subsection (1) of this section or take any action before the operative date specified in subsection (1)
of this section that is necessary to carry out the provisions of section 6 of this 2009 Act. Any rules adopted by the commission under this section do not become operative until on or after July 1, 2011.

SECTION 8

Rule sunset provision:
Sections 6 and 7 of this 2009 Act are repealed on December 31, 2015.

SECTION 9

Requirements for DEQ reporting to the Oregon legislature:
(1) The Department of Environmental Quality shall report on the implementation of sections 3 and 6 of this 2009 Act to:
   (a) The interim legislative committees on environment and natural resources on or before December 31, 2010; and
   (b) The Seventy-sixth, Seventy-seventh and Seventy-eighth Legislative Assemblies in the manner provided by ORS 192.245.

(2) The reports required under subsection (1) of this section must contain a description of:
   (a) Rules adopted under sections 3 and 6 of this 2009 Act;
   (b) The manner in which the Environmental Quality Commission complied with the requirements of sections 3 and 6 of this 2009 Act in adopting the rules;
   (c) Significant policy decisions made by the commission in adopting rules under section 3 of this 2009 Act; and
   (d) The anticipated effects of the December 31, 2015, repeal of sections 6 and 7 of this 2009 Act on the availability of low carbon fuels and the development of biofuels production facilities and electric vehicle infrastructure in Oregon.
### XI. Advisory Committee Member List and Operating Principles

#### 1. Low Carbon Fuel Advisory Committee Member List

<table>
<thead>
<tr>
<th>Name</th>
<th>Affiliation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mark Reeve, Chair</td>
<td>Reeve Kearns, PC</td>
</tr>
<tr>
<td>Emily Ackland</td>
<td>Association of Oregon Counties</td>
</tr>
<tr>
<td>Carrie Atiyeh (alternate)</td>
<td>ZeaChem</td>
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<tr>
<td>Jonathan Burke</td>
<td>Westport Innovations Inc.</td>
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<tr>
<td>Todd Campbell (alternate)</td>
<td>Clean Energy</td>
</tr>
<tr>
<td>Eric Chung</td>
<td>PacifiCorp</td>
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<tr>
<td>Kyle L. Davis (resigned)</td>
<td>PacifiCorp</td>
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<tr>
<td>Marie Dodds</td>
<td>AAA</td>
</tr>
<tr>
<td>Brian Doherty (alternate)</td>
<td>Miller Nash/WSPA</td>
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<tr>
<td>Katie Fast (alternate)</td>
<td>Farm Bureau</td>
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<tr>
<td>Abe Fouhy</td>
<td>American Hydrogen Association Northwest</td>
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<tr>
<td>Jana Gastellum (alternate)</td>
<td>Oregon Environmental Council</td>
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<tr>
<td>Robert Grott</td>
<td>Northwest Environmental Business Council</td>
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<tr>
<td>Sam Hartsfield</td>
<td>Port of Portland</td>
</tr>
<tr>
<td>Marion Haynes</td>
<td>Oregon Business Association</td>
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<tr>
<td>Ian Hill</td>
<td>SeQuential Biofuels</td>
</tr>
<tr>
<td>Frank Holmes</td>
<td>Western States Petroleum Association</td>
</tr>
<tr>
<td>Brock Howell</td>
<td>Environment Oregon</td>
</tr>
<tr>
<td>Randy James</td>
<td>Portland and Western Railroad</td>
</tr>
<tr>
<td>Michael A. Johns</td>
<td>Lane County Department of Public Works</td>
</tr>
<tr>
<td>Christine Kelly</td>
<td>Oregon State Univ: Chemical, Biological &amp; Env. Engineering</td>
</tr>
<tr>
<td>Mark Kendall</td>
<td>Oregon Environmental Council</td>
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<tr>
<td>Dan Kirschner</td>
<td>Northwest Gas Association</td>
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<tr>
<td>Tom Koehler</td>
<td>Pacific Ethanol</td>
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<tr>
<td>Allison Koenker (alternate)</td>
<td>Associated General Contractors</td>
</tr>
<tr>
<td>Geoff McPherson (resigned)</td>
<td>Citizen</td>
</tr>
<tr>
<td>Matt Michel</td>
<td>Canby Utility</td>
</tr>
<tr>
<td>David N. Patterson</td>
<td>Mitsubishi Motors R&amp;D of America</td>
</tr>
<tr>
<td>Harrison Pettit</td>
<td>ZeaChem Inc.</td>
</tr>
<tr>
<td>Andrew Plambeck</td>
<td>Ecumenical Ministries of Oregon</td>
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<tr>
<td>Sam Pounds</td>
<td>Tidewater Barge Lines</td>
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<tr>
<td>Joshua Proudfoot</td>
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<td>Marcy Putman</td>
<td>Labor Union – IBEW</td>
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<td>John Rakowitz</td>
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<tr>
<td>Danielle Romain</td>
<td>Oregon Petroleum Association</td>
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<tr>
<td>Paul Romain</td>
<td>Oregon Petroleum Association</td>
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<tr>
<td>Bob Russell</td>
<td>Oregon Trucking Association</td>
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<tr>
<td>Jennifer Shmikler</td>
<td>Farm Bureau</td>
</tr>
</tbody>
</table>
2. Advisory Committee Operating Principles

The members of the Low Carbon Fuel Advisory Committee agree to operate under these operating principles.

A. Purpose

The 2009 Legislature authorized the Environmental Quality Commission to adopt low carbon fuel standards in order to reduce greenhouse gas emissions from gasoline, diesel, or any fuel that substitutes for gasoline or diesel.

DEQ will be drafting rules for review and submitting to the commission for approval. DEQ convened this advisory committee to discuss and give input on specific policy and technical issues related to the low carbon fuel standards, including review of DEQ’s draft fiscal and economic impact statement.

B. Low Carbon Fuel Advisory Committee Charge

DEQ will draft rules for low carbon fuel standards.

1. The advisory committee will discuss and give input on program requirements and issues as part of the rulemaking process, within the timeframe provided. DEQ is seeking diverse input into policy and technical issues regarding implementation of low carbon fuel standards in Oregon.

DEQ is seeking input on the following issues. These are described in more detail in Agenda Item C for the November 3rd advisory committee meeting entitled “Rulemaking Process and Policy Issues.” Where an issue has a specific requirement or mention in House Bill 2186, the section is noted.

- Consumer cost safety net (exemptions and deferrals to mitigate a non-competitive price of gasoline or diesel) (Section 6, (2)(d))
- Fuels covered under a low carbon fuel standard (including which ones are opt-in) (Section 6 (2)(b)(C))
- Exemption threshold and exempted fuels (Section 6, (2)(b)(E), and Section 6, (4)(a)-(d))
- Oregon’s approach to lifecycle analysis and calculating fuel carbon intensities (Section 6, (2)(b)(B)), including drive train efficiencies, (Section 6 (2)(b)(G))
- Economic analysis (Section 6 (3)(a) and Section 6 (3)(d))
- Regulated parties
- Credits and deficits
- Compliance scenarios and feasibility (Section 6 (3) (a))
- Electricity-specific issues
- Short term and forecasted fuel supply deferrals (Section 6, (2)(b)(D))
- Indirect land use change (Sec. 6 (2)(b)(B))
- Process for establishing new fuel pathways
- Implementation issues (Section 6 (3)(c))
- Phase-in schedule (Section 6 (2)(b)(A) and 6 (2) (c))
- Public health and environmental impacts (Section 6 (3)(a) and (b))
- Effect of sunset (Section 9 (2)(d))
C. Low Carbon Fuel Advisory Process and Operating Principles

A. Process: The advisory committee is being asked to discuss and give input on key program policy and technical issues influencing the design and implementation of low carbon fuel standards in Oregon. The committee’s discussions will be used by DEQ in forming its draft rules for low carbon fuel standards, which will then be proposed for broader public review and comments as part of DEQ’s rulemaking process. DEQ is seeking diverse input from key stakeholders into the design of low carbon fuel standards. Recognizing the complexity of low carbon fuel standards, DEQ will not seek consensus positions from the committee, nor will the committee be asked to vote on specific issues. However, DEQ would give great weight to any committee recommendation in which there is consensus. Meeting summaries and a final report will document the different perspectives and recommendations of committee members.

The product of this advisory committee will be a DEQ report summarizing advisory committee discussions and recommendations to the DEQ Director. DEQ staff will draft the report in collaboration with the advisory committee to ensure accuracy and completeness. This summary report will be made available to the public at the end of the committee process and as part of DEQ’s subsequent low carbon fuel standards rulemaking.

B. Operating Principles

The Chair will be responsible for:

1. Helping facilitate the conversation so the committee stays focused on the issues and objectives and all perspectives are heard; and
2. Helping all members adhere to the process and ground rules.

All Low Carbon Fuel Advisory Committee members are asked to commit to the following ground rules:

1. Attend each meeting to ensure continuity throughout the process;
2. Prepare for and set aside time for the meetings;
3. Treat everyone and his or her opinions with respect;
4. Allow one person to speak at a time;
5. Comment constructively and specifically;
6. Engage in honest, respectful, constructive, and good faith discussions;
7. Consult regularly with constituencies and provide their input;
8. Stay focused on the specific topics for each meeting;
9. Not attempt to represent the views of any other committee member or the Low Carbon Fuel Advisory Committee as a whole to the public or media; and
10. Appoint one alternate if needed. It is each committee member’s responsibility to fully brief the alternate on all relevant issues and prior committee discussions. DEQ would appreciate being informed in advance if an alternate will substitute for a primary committee member at a meeting.

C. Public Records and Confidentiality: Low Carbon Fuel Advisory Committee records, such as formal documents, discussion drafts, meeting summaries, and exhibits are public records. Low Carbon Fuel Advisory Committee communications are not confidential and may be disclosed. However, the private documents of individual Low Carbon Fuel Advisory Committee members and the Chair generally are not considered public records if the Agency does not retain copies.

D. Information Exchange: Low Carbon Fuel Advisory Committee members will provide information as much in advance as possible of the meeting at which such information is used. The members will also share all relevant information with each other to the maximum extent possible. If a member believes the relevant information is proprietary in nature, the member will provide a general description of the information and the reason for not providing it.
D. Public Involvement

All meetings will be open to the public and have a limited time set aside for the public to speak. Additionally, citizens who wish to submit comments are encouraged to communicate directly with a Low Carbon Fuel Advisory Committee member or to communicate by submitting written comments through the website: www.deq.state.or.us/committees/advcomLowCarbonFuel.htm. All public comments received will be compiled and included as an Appendix in the Low Carbon Fuel Advisory Committee’s Report to the DEQ Director. In mid 2010, with guidance from the Committee’s report, DEQ intends to develop proposed Low Carbon Fuel Standard rules and conduct an open and public rulemaking process. DEQ will seek and carefully consider broader public and stakeholder input. DEQ’s final rule proposal may be modified based on public comment. Each committee member can provide additional comments to DEQ on the LCFS rule during the public comment period of the rulemaking. DEQ hopes to take a final proposed LCFS rule to the Environmental Quality Commission (EQC) for consideration in late 2010.

E. Process Support

DEQ is convening the Low Carbon Fuel Advisory Committee and will be the primary agency providing staff support. DEQ will consult with other agencies and stakeholders, as needed, to support this project and the Low Carbon Fuel Advisory Committee.

Briefing Materials: DEQ staff will email briefing materials at least one week prior to each meeting. The committee Chair will lead the Low Carbon Fuel Advisory Committee in a discussion to gather input from Advisory Committee members on the issue at hand.

Meeting Summaries: DEQ staff will prepare Low Carbon Fuel Advisory Committee meeting summaries. Meeting notes will summarize significant issues raised during the discussion, whether and how issues were resolved, and individual committee member recommendations regarding program elements, implementation, and other action items. The meeting summaries will be posted on the Project website at: www.deq.state.or.us/committees/advcomLowCarbonFuel.htm.

Advisory Committee Conclusion: As noted above, DEQ will develop a report on the advisory committee discussions and recommendations. If the advisory committee achieves consensus on any issue, the report will reflect that, otherwise the report will reflect the perspectives and recommendation of any of individual committee members. The report, after review and modification by the advisory committee as needed, will be submitted to the DEQ Director.

F. Communications and Media Coverage:

The DEQ Air Quality Division headquarters office will respond to public or media inquiries associated with the organization, structure, process, and goals for the low carbon fuel standard rule development and advisory committee. While free to communicate and share individual perspectives with the media and others, DEQ asks advisory committee members to offer their personal viewpoint only and to refrain from speaking for other committee members or the advisory committee as a whole. We ask committee members to vet ideas and issues concerning the low carbon fuel standard at committee meetings before discussing them outside of the committee structure, since the way in which positions are publicly represented may affect the ability of the Low Carbon Fuel Advisory Committee to work together. When asked for information about the purpose or activities of the committee DEQ asks you to refer others to the project website: www.deq.state.or.us/committees/advcomLowCarbonFuel.htm.
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Oregon Low Carbon Fuel Standards Report

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Please note that numbering in this appendix follows the numbering in the LCFS report for consistency.
VI. Oregon LCFS Program Design

1. Summary of LCFS Program Design

November 16, 2010 Advisory Committee Meeting

- When you talk about covered fuels and then refer to the section of the report where it is defined, as an example of something we don’t want to have covered now, it says ethanol derived from biomass sources such as Brazilian sugar cane, food waste, wood waste and agricultural waste, it seems like you could say purpose-grown crops or something else in there such that this list is not meant to be exhaustive. It seems like this list ought to have broader options.

- Figures 3 and 15 in report depicting the transport of LNG in or out of pipeline look incomplete to me because there will be natural gas piped possibly to California or even Washington and will trucked into Oregon, as opposed to being transported via an LNG barge. **Response:** That statement is intended to say that LNG could be trucked into Oregon. So you're assuming it gets trucked into Oregon from somewhere else in the U.S.? **Response:** Right.

- For LNG, is the fuel regulated when the barge stops and actually unloads the LNG onto a cube trailer? **Response:** We haven’t figured that out yet. Whoever is dispensing it, if they are getting fuel from a barge or trucked into Oregon, they would be the regulated party. If it never gets co-mingled with the pipeline. It’s unclear when you have the LNG barged or trucked into Oregon. It could be confused with the second schematic.

- There was a lot of debate around where the responsible party if it was brought in from out of state. There was a question on jurisdiction in the example of a Boise distributor that brings a load of fuel FOB into Oregon. You’re saying that the compliance obligation for that fuel will be on the Boise distributor, are you saying you’ve got the regulatory authority to regulate outside the state, and/or are you just going to shut down the market? **Response:** Once they bring it into the state, they’re responsible. **Comment:** You’re saying then that out of state parties are responsible. **Response:** As the same way they are for the fuel tax and fuel quality standards required in Oregon.

- In the At-A-Glance table for 2B, you have listed potential Opt-in parties as utility companies, energy service provider, or energy that goes into fuel dispensing equipment in Oregon. However, in that section of the report, it only mentions the utility companies. **Response:** That is a mistake. They should read the same. **Comment:** I also wondered if an energy service provider was essentially a fuel provider. **Response:** In the report itself on page 55, the potential opt-in parties in Oregon are the three natural gas companies who own the majority of fueling stations, or CNG fleet owners who own fuel dispensing equipment. **Comment:** Okay, I got thrown off where it says proposed, and then it says potential opt-in parties, and I didn’t know how you were defining natural gas companies. **Response:** It just needs clarification to indicate that anyone who owns or could own dispensing equipment could be an opt-in party.

- How does the utility play a role in this? There are some concerns in terms of competition, because a utility can create a very uncompetitive market place, and it isn’t clear if the regulation being proposed considered that, and whether it would require a utility to create shareholder subsidiaries because there is no way in a mature market that fuel providers can compete with utilities if they are able to cross-subsidize their rate base. Furthermore, for those non-participating rate payers, it doesn’t seem fair why they would be paying for infrastructure. That’s the issue currently being discussed with the California Utility Commission, and it is something that needs to be addressed in Oregon as well. **Response:**
(Wallace, ODOE) Utilities cannot sell electricity now into the transportation sector, and the PUC is the entity that regulates that. We’re addressing that issue now for electric vehicles, but for CNG that has been addressed a long time ago. In fact at one point, NW Natural used to sell to the public, and they were forced to move their compressor behind the fence and cease and desist.

- For 2D (in the At-A-Glance section of the final draft report), there was something that really concerns me, particularly for utilities. The language on page 58 states that if you put biogas into the pipeline, the compliance obligation no longer falls on the producer but instead would go to the utility. **Response:** It would go to whoever owns the fuel dispensing equipment. The language which states that “The owner of the fuel dispensing equipment can show that the fuel was used for transportation, but the producer cannot if the fuel is injected into a natural gas pipeline.” Clean Energy produces biogas from all over the country and then we pay a transfer rate to assure that those molecules can be tracked for the purpose of renewable portfolios. I would assume that the same logic that would be used for renewable electricity generation for electric vehicles, so if you assume that, this is actually inhibiting the potential for or doing production in Oregon completely because if I have no incentives to do biogas, people are going to lose that benefit immediately when the biogas goes into the pipeline. That would be a significant roadblock for us. **Response:** Does most of the biogas going into the pipeline in California get used in the transportation sector? Yes, because the customer is purchasing that quantity from us. They are creating the reason for us to pull that biogas from the landfill that would otherwise be wasted. So we contract that distribution with the utility. **Response:** But in fact, what happens is the customers may or may not use that biogas, but they have paid for it to be produced. It works just like green power for electricity. I’m paying for 10% green power, but may never actually consume that renewable power. But I am creating that market demand for the renewables to be supplied, and it’s the same concept. If I’m a producer and I start biomethane projects in the state of Oregon, being pipeline accessible is an advantage because there’s a line of transfer that is created so that I can actually power those vehicles that can make that case. If you take away the ability to put that biogas into the pipeline, my customer base shrinks and I can’t provide those benefits. The pipeline doesn’t make natural gas, it only delivers it. The actual production needed to make the fuel transportation-worthy is if you compress it or liquefy it, and that is why CNG and LNG are regulated completely different. The way the California Air Resources Board defines the regulated party as whoever has the ability to compress the gas at the station, and whoever delivers that natural gas to a transportation station is how LNG is regulated because otherwise you could put it anywhere and you’d have no idea how or if it would be used for transportation. That’s why it’s regulated the way it is. So if we’re compressing natural gas at a station and we deliver biomethane to that station and pay for that transfer, we should be the one to get that credit, otherwise there’s no reason to produce biomethane unless you’re a utility and you’re using the RPS. If you want it in the transportation sector, you have to make that change.

- So how would you make that happen? **Response:** (WSPA) I will provide my thoughts in the written comments, but I think it would be something along the lines of the person that receives custody of the biogas in the pipeline.

- Is the proposal for addressing fuel used in short line railroads something that has been discussed previously? **Response:** It isn’t something we have discussed as a committee. It was an issue during the authorization of House Bill 2186 and the question of how to handle fuel to be used in short line railroads was discussed in the Legislature. At this point, we don’t have enough information. Real briefly, the issue with potentially using low carbon fuels in locomotives is that engine manufacturers don’t warranty biofuels to be used in locomotive engines. This is an issue that may get resolved in the long run, and renewable diesel may not have that same issue, but for now we’re thinking about biodiesel as not being able to be used in locomotives. And then you’ve got the fuel distribution network for short line railroads.
is captive in that fuel distributors are distributing primarily the short line customers, and since they can’t buy any biofuels they basically have to buy 100% credits to comply with the LCFS, and we don’t really know at this point how that will play. We are hopeful that the credit market will work well but when we have one small sector that is completely dependent on the credit market, we think it is premature to apply the fuel in that scenario. So what we’d like to do is by 2016 when we conduct the comprehensive program review, we’ll have a lot of information about how well the credit market would work, the fuel distribution network and quantities/volumes of fuels. For perspective, we’re talking about a very small percentage of transportation fuel that would otherwise be subject to the LCFS. What about the language in the rationale that says there’s nothing in the LCFS that would prohibit regulated parties from obtaining unblended fuels, and that was included to address harborcraft, how is that any different for the locomotive operators? Why should DEQ be exempting anything that was not specifically mentioned in the legislation? **Response:** For the other markets, the fuels distributors will be able to meet most of their compliance obligation by blending biofuels. They may have some customers that won’t be able to use their product and will have to buy credits to cover that portion, we think in this case it may be that their primary or sole customer can’t use biofuels, and they essentially have to purchase electric vehicle credits for 100% of their compliance obligation, which we think is premature before seeing how the market will work, so it’s a very unique circumstance. And the harborcraft people haven’t argued this same point? **Response:** We haven’t heard from them that they have the same fuel distribution problem

- I recognize the unique character of that small market share, but am sensitive to the fact that for many years there has been, albeit anecdotal, and not standard testing of a number of short lines that have blended biofuels and have we heard mixed stories about an unsatisfactory experience. It’s not just the engines, but I understand its’ also retrofits and associated warranties. Most of their fleets are somewhat legacy blends, but parts are still an issue. **Response:** Hopefully one way or another, this issue will get resolved by the mid-program review, and there are a lot of reasons to wait and observe for now.

- My concern with choosing a number (360,000 gallon threshold for fuels used for transportation in small volumes) we are inadvertently discouraging pilot and demonstration plants from locating in Oregon, and that is a very important stepping stone to commercial scale for new fuels. ZeaChem’s plant is going to have a capacity of 250,000 gallons per year, and so I think at that scale it’s still in the experimental phase, it’s not commercial scale, and I think it would be preferable to have an opt-in status depending on how well the plant is running. I don’t know where they would fit in the proposed exemptions. Obviously they are above the 50,000 gallon threshold, but they may be under 360,000 gallons but I’m not sure if that would apply to them. And the other issue I see is what if you get imported fuel from out of state that are outside of the categories, and how then do you define the category. You may be creating a disincentive to begin their development process. I would recommend a clarification of the 360K and what that applies to and how that gets parsed out. **Response:** I’m not sure I understand how the 360K threshold might create a disincentive. What you’ve got is a capacity, but under a demonstration scale you’re really running campaigns. You’re building a capacity but it’s an experimental facility and under those circumstances, you aren’t necessarily going to be hitting your pathway CI numbers, it’s going to be really irregular. And so if you were in a position to take advantage of being a regulated party, you would want to do so. **Response:** It almost sounds like we need another exemption for a pilot facility that could apply for pilot status if they were not in commercial operation. **Response:** (Chair) This also has to square with how we deal with new fuel pathways. Are you talking about a new pathway, or just making the same product the same way or a different pathway? Because with a different way, don’t you have already some threshold? **Response:** We do, but I think what Harrison is saying is that if a company is still working on their process and wants to pilot a demonstration scale, they want to avoid all of that. I’m saying that we would want the ability to opt-in to take advantage of it. You want the credits and want to be in the game, but it’s very likely that you will not be in the game until you’ve refined your process.
Response: So what about an option for an individual small scale producer that produces greater than 50,000 gallons that is in pilot mode can apply for an exemption? They’d have to declare themselves to be a pilot facility and it seems like it would make sense if we had something like that. Does anyone have any objection to that concept, of having an opt-in option? There would have to be some demonstration that it was a pilot operation. One distinction would be that the facility is demonstration or piloting a new technology, not one that already exists. (Chair) There probably also ought to be a time limit on it because the program overall wants to put all the low carbon producers in to the program so that credits can be available for use. Response: (ZeaChem) But they don’t get the benefit, and you’d want to seek that benefit when you are capable of doing so, and I think this can be set up appropriately to achieve that. I think a demo may remain a demo, and then you shut it down once you’ve built a fifty million gallon plant at that site or nearby.

- Have you determined whether those facilities exist? Response: Not that I know of, but it could happen in the future. For those who are contemplating import of low carbon fuels in Southern California, it is really confusing to figure out what stations actually receive the molecules of biogas that are put into the pipeline and at what volumes. There will be times when a facility won’t import, and it’s really up to a utility with regard to how they purchase their gas.
- What about facilities that would eliminate truck stop idling would that fall under this exemption? Response: I think it depends on who owns the equipment.
- It seems a little inconsistent with CNG and electricity, because for CNG the proposal before us, if someone wants to put biogas into the pipeline it gets tracked the same way as green electric power. For example, when electricity derived from solar or wind power gets sold, the customers know what they’re buying, but the exact electrons that they receive aren’t going to all be generated from green sources. But there’s a contract in place for that particular commodity and we can track where it goes.
- So is your suggestion that we use similar language that has to do with the chain of custody being documented by the dispenser? Response: (ODOE) Yes. Response: The purpose of this program is not to reduce the carbon intensity of electricity production but it intended to reduce the carbon intensity of transportation fuels. There are other programs such as the Renewable Portfolio Standard and other ways of affecting the carbon intensity of electricity itself. What we’re trying to do with electricity is capture what its carbon intensity is as a factor in calculating the carbon intensity of electric vehicles but not trying for implementations that account for it, unlike the biofuels which are being produced specifically as transportation fuels. Response: (ODOE) My concern is that it is not consistent with some of the other efforts being made in Oregon to reduce greenhouse gas emissions, like Senate Bill 1059, which tracks on a county by county basis and looks at the utility aggregated mix of that county. Those numbers are drastically different than what is being proposed here and ODOE is looking at the transportation sector of a utility different than the residential, industrial and commercial sectors, so it’s all pulled apart. You’re looking at it as if it’s part of the overall field and it’s not. Nor will it be counted that way, because the transportation sector is going to be looked at separately.
- This is too small a market to affect a change in the decision making processes of utility companies, so the question then becomes, can you put the burden on individual entities or users to prove through chain of custody that they’ve done something exceptional so that there is an outlet for that but the burden isn’t on DEQ. There should be a process that utilities can go through to show that they’ve done something to distinguish the carbon intensity of the electricity they generate. Response: The purpose of this program is not focused on community comparisons. Response: (ODOE) There’s a statewide program for 2011 that SB1059 came out of, but we still have the statewide analysis to conduct. SB1059 was a separate mandate for Metropolitan Planning Organizations. I don’t see what the distinction is for biomethane and other renewables. Biomethane can be sued for power generation or transportation, and if you try to identify
where the renewables are coming from, you run the risk of double counting which diminishes the ability of the program to create real carbon reductions. It would take away incentives for an industry to move in that direction. **Response:** Those are valid points. The other side of that is if you are purchasing an electric vehicle, the benefit that would come from that electric vehicle would solely depend on where you live because you don’t have control over your service provider district and what choices are made in terms of renewables there. I’m not sure that accurate, because I could produce biomethane and power a fleet of transit buses in Portland for example, and they could use that biogas. **Response:** In the electricity sector though, the question is does the role of electric, which is predominately from the Bonneville hydroelectric source which is very low carbon intensity as compared to the Pacificorp and PGE service territories, and that is where the population centers are located that can most likely support electric vehicle infrastructure. So you’ve got a mismatch where the likely market is for electric vehicles compared to where the low carbon electricity is generated, so we’d be creating a system that would not likely create the right incentives for getting electric vehicles infrastructure. Beyond the timeframe of the LCFS, those electric vehicles will still be generating carbon reduction benefits for a long time. There’s no right or wrong answer to this issue, but the net result is that the statewide average electricity carbon intensity then makes that all neutral with regard to the incentive for putting electric vehicle infrastructure in place. I have no problem with a statewide application I’m just surprised that there would be no incentive for low carbon fuels in a low carbon fuel regulation.

- If you go back and adjust the value of banked credits, it’s going to put a lot of companies out of compliance, **Response:** The concept is that if we add indirect land use at some point in the future, some of those low carbon credits will have less value and the baseline would be off if we didn’t adjust it, and any banked credits would be overstated. So this wouldn’t affect a past-compliance determination, but the use of those banked credits in a future year needs to be put on par with newly generated credits. What would happen to a regulated party that is just barely in compliance at that point in time? Would you readjust the baseline before they are out of compliance so they don’t have excess credits that then need to be adjusted? **Response:** Adjusting the baseline doesn’t affect their compliance, it affects how far we have to go to get the ten percent reduction. So what we’d be doing is calculating what the carbon intensity at the start and end of the program is and getting a ten percent reduction. I don’t think it affects an individual company’s compliance unless they were relying on those banked credits for next year’s compliance obligation. If, as a result of the mid-program review DEQ decided to add an indirect land use change value to the carbon intensity of a fuel, regulated parties will know a couple of years in advance that that change is coming and there will be some established amount of time before it goes into effect. If the assumption was that the very next year regulated parties would be able to use those credits the following year but they couldn’t, then that would be a shock to the system. But you can’t allow the banked credits to be overvalued compared to the newly generated credits. Starting with a number to represent indirect land use change like CARB is using and then adjusting that number at a later date as more accurate information becomes available would result in a smaller adjustment to those banked credits. Indirect land use needs to be included. What numbers should be sued I am not prepared to take a position on at this time, but there is enough out there that says indirect land use should be a component considered in the LCFS analysis. **Response:** This is probably another one of those cases where there isn’t a right or wrong answer, and DEQ encourages committee members to articulate their position in the exit survey. We realize there is not consensus on this issue within the committee, and we took the various positions into account when making this proposal. They way I read and understand DEQ’s position is that there isn’t enough certainty behind the indirect land use change numbers and it’s essentially a wait and see approach, and once there’s enough confidence to move forward they would take action. I thought WSPA would be supportive of DEQ’s approach, because I took it as if a fuel producer has any question with regard to my CI reduction associated with my fuel when I’m generating
credits I may not want to bank them but instead I may just want to sell them because I don’t know if those credits will hold their value. The problem I have with this proposal is that the people who sell the credits don’t get dinged, the people who bank credits do. And a regulated party who is counting on those banked credits to help comply with the standard in the later years of the program gets screwed because the game has changed midway through. I think you have some unintended consequences with 8A (At-A-Glance) because it’s not only not fair across the board, you’re going to have a dumping spree of banked credits by those who think they might be at all in jeopardy of losing monetary value of those banked credits. If you want to avoid having to go back and re-calculate emission reduction credit values, you should also change the value of any credit that is generated from that decided date that the change takes effect moving forward. If my strategy is to bank generated credits for future years I get penalized because I may be more efficient and I don’t need those credits, so that’s a raw deal. **Response:** The ideal scenario for the present is that we would have great science that would tell us what the land use change numbers should be and we’d do it from the beginning. But currently, the state of the science isn’t there yet and in we also have a lot of questions about other indirect affects and whether biofuels are being unfairly penalized by an indirect affect and the divergence in the numbers of land use are so wide, the safe bet is to go with the cellulosic ethanol and what we’re saying is that we not going to take corn ethanol and add an indirect land use change number to it at this point but stakeholders are on fair notice that those credits may be worth less in the future as the science determines what those numbers should be. So it wouldn’t be of great benefit to bank a bunch of ethanol credits for long term as this policy approaches. But if we went with the approach you are suggesting and provided a protection for credits banked under certain set of rules and you should be allowed to keep them at the value they had when generated, the problem is if we have a large volume of banked credits, that’s going to dis-incent future production of low carbon fuels. We’re trying to balance the whole scenario. I’d say include CARB’s values for indirect land use change right now. You’re saying DEQ won’t start regulating until the Department feels like there is enough certainty as to which numbers should be used and sorry to those who banked their credits, you lose and the people who sold them win, and I don’t think that’s fair at all. I think that will create a high carbon flood in the market system, and they will take as many credits as they can and then we’ll see a large exodus of those high carbon fuel producers from the LCFS program. **Response:** Let’s have everyone clearly state their position on this issue in their exit surveys and in your comments on the report as well and we can give this some more serious thought.

- The EER figure being proposed for heavy duty CNG and LNG is a California-specific EER which accounts for the legacy vehicles on the roads today, so this is not what is expected for future vehicles. I would encourage DEQ to contact Cummins Westport and other manufactures for a more accurate EER value for those types of vehicles because this is not accurate.

- There was discussion earlier about adopting the California LCFS reporting system and this is quite contrary to that system, so it will require a lot of programming modifications and guidance development. So I would challenge the assumption that Oregon could use California’s system without making significant modifications to it. An Oregon-specific program will require additional resources to build and implement.

- In California, credits cant’ be used until the following year so that they can be verified by CARB. **Response:** The regulated parties will be responsible for calculating the value of credits generated and reporting that information to DEQ. DEQ will not be going out and verifying all these credit transactions. We may spot check some, but the essence of the annual report is to show that you credits and deficits match and that you bought credits from somebody who reported to us that they generated credits. The regulated parties will have to be buying and selling credits that they know are valid. DEQ will not be
certifying credits ever, even at the end of the year. DEQ will check the reports and make sure the credit transactions balance, but I don’t see what the hold up of buying real time credits would be.

- Would all fuel providers have to register with the state? **Response:** They would anyway. They are already automatically a regulated party, so if you think you’re buying credits from an opt-in, you’d want to verify that they’ve opted in and that would be your due diligence as a buyer that you aren’t buying more credits than they produced but otherwise you don’t know if they’ve already sold their credits to somebody else.

- The temporary deferrals are looking at two components. Some of the deferrals are looking at supply issues while the other is looking at cost issues to the consumer, but those two things are intertwined and under the Type 1 description where the regulated party is still having to comply, I can envision a scenario where regulated parties would continue on no matter what the costs just to be able to be in compliance and not have that compliance burden hanging over them. A regulated party is going to want to be in compliance and cost is a secondary factor versus the supply question. **Response:** Even though they would still be in compliance carrying over? But they wouldn’t be, they would have a continuous increase of that obligation and I see that as potentially complicating because I see both components as one issue. A supply problem may happen, but you won’t have the 12-month rolling price average to address that for a year, so you’ll have a huge cost impact immediately. **Response:** Type 1 was designed for a small debt that is over five percent and not likely to affect the price, and regulated parties will have to decide whether to buy credits now or decide to allow a deficit to accrue under the assumption that credits will be cheaper next year, but that is only an option when the deficit is small and doesn’t have the potential to affect the price. If it’s a large deficit under Type 2, it will be forgiven during the deferral period. In balance there is not going too far on either side with Type 1 or 2 because under Type 2 you’re losing the benefit of the program during a deferral period and you’re allowing credits to continue accruing so you aren’t dinging biofuels producers but you’re still diluting the program so you aren’t getting any benefit from the program this year and you’re also allowing banked credits to accumulate you’re going to get less benefits next year so it’s something you’d only want to do if it’s a large long-term disruption in supply. (Chair) The term “available” is used, and obviously price does matter because more things are available if you’re willing to pay more. Do we have some threshold or significance to determine what is “available”? **Response:** Not really. If there is a fuel that is being delivered to Oregon the previous year I would say that that fuel is available. **Response:** We can address that in the guidance that accompanies the rule, but we don’t have that figured out at this point. Also, there is a proposal on the table by DEQ to identify when a deferral is triggered, but we still don’t know what the deferral means. **Response:** For this one specifically or for all of them? For this one specifically, you’re identified the 0.01% trigger, but haven’t articulated how the program would be affected. **Response:** There are two proposed ways to address that type of scenario. The first is to administratively defer the LCFS for a week to a year and the second is to go through a rulemaking to adjust the compliance schedule end year. If it gets deferred for a year the standard would go right back to where it would have been the next year.

- We may want to change the terminology that currently reads “Initial physical pathway report” in the reporting section to distinguish the physical route a fuel is transported on from the pathways associated with assigning a carbon intensity value to a fuel type.

- Correct me if I’m wrong, but I thought the concept was that the physical pathway was to document that you qualified for a specific lookup value on the table so it’s not just new fuels. **Response:** (Chair) So if that is the case, basically all reporters would have to do something at least once. **Response:** That is correct. It’s a one-time report for each fuel from each company until a change occurred that would affect the carbon intensity of a fuel type, at which point they would be required to submit a new report.
- If regulated parties were able to roll up all the identical pathways and report one number at the end of the year that’s one thing, but if they were required to report each transaction that would be very burdensome. **Response:** We welcome comments and suggestions on how to do this differently, because we only want to collect the data that will help us determine whether a regulated party is in compliance and no more.

- If regulated parties were able to roll up all the identical pathways and report one number at the end of the year that’s one thing, but if they were required to report each transaction that would be very burdensome. **Response:** We welcome comments and suggestions on how to do this differently, because we only want to collect the data that will help us determine whether a regulated party is in compliance and no more.

- With regard to meeting compliance obligations, do you need anything in the way of enforcement that says failure to submit a required report is a Class 1, 2 or 3 violation? **Response:** Let me briefly explain DEQ’s enforcement rules. There are several things that happen in Division 12. One is we classify all violations as either Class 1, 2, or 3, with Class 1 being the most serious violations like a violation of a standard. A Class 2 violation would typically be recordkeeping violation, and this is the default class that all violations fall into unless otherwise specified. There are penalty matrices, and the penalty for a Class 1 violation by a large business is bigger than a penalty for a Class 3 violation by a home owner, for example. So you have to identify which penalty matrix is appropriate for the violation based upon the classification. If those things aren’t identified it all defaults to a moderate level so the program rules would work without any specific changes, but we do want to differentiate between the more serious violations like not complying with the standard against a more minor violation like failure to submit a report on time. Since the first two years of the program will be reporting only, there wouldn’t be any major violations during that time, and any reporting violations would default to the Class 2 violation category.

- Is there an educational component? Will it be that a regulated party could receive a Class 2 violation before being trained on how to comply? **Response:** Beyond the initial reporting years of the program, once the rules are defined in terms of classifying violations, then there is our existing enforcement guidance about how we respond. So if an inspector discovers a violation, and it’s the first violation and the violating party is cooperative and correct the violation immediately then they get a warning letter versus something else where it’s a repeat violation and the violating party doesn’t cooperate, the violating party in that case would not get a warning letter but would instead receive a referral for enforcement.

- In terms of funding mechanisms for the program, why not don’t we a discussion about a funding mechanism? **Response:** When House Bill 2186 was authorized it did not come with funding, and DEQ let the Legislature know that we could use in-house resources to develop the program, but that the Department wouldn’t be able to implement the program without additional resources. Right now when you look at the schedule the initial program implementation is reporting so the resource needed primarily is resources to develop the database to receive reports and conduct outreach, and we’re fairly hopeful that a combination of federal funding and in-house resources will be able to handle that. So the significant part of the budget requested would be when the compliance obligation begins in 2014, and we will have to have a budget request to go along with it. We will be discussing this with the Legislature this session, but it will not be presented as a budget request in 2011. It would probably be a budget request in the 2013 session, but remember there is currently a program sunset in 2015 so that issue will have to be addressed in 2013 along with other questions still remaining at that time with regard to the path forward.

- And that could be a fee-based funding model? **Response:** Whether it was general fund or a fee-based method, it would still have to go before the Legislature. We haven’t investigated that at all, but we anticipate that if California has 40 FTE to implement their LCFS program, just on the back of the
envelope, Oregon is about one tenth the size of California, and we will be heavily riding on their program for ideas on how to implement the Oregon LCFS, we will probably need 2 or 3 FTE to run this program, but have not yet conducted a detailed analysis. In the 2011 Legislative session, DEQ will not be taking any position on whether the sunset should be repealed or not, but as part of the report, we will identify what the potential impacts of the sunset are and it will be informational at this point.

- As part of the rulemaking process, DEQ must submit to the Legislature a Fiscal Impact Analysis. Does that Fiscal Impact Analysis include any estimate in terms of need for staff? Can you do that in the absence of any authorization for staff? **Response:** Yes. Is that typical? **Response:** The thing that’s not typical about this program is that it’s got a phased and very delayed compliance element to it. So typically when we’re adopting a rule it’s got a fiscal and economic impact that we can identify, and this might be a little more speculative. But with the requirement in the Oregon Administrative Procedures Act, we need to disclose all the information that we have, and so we can provide what we know, but not what the fiscal impact is going to be.

- I’d like to take this opportunity to say publicly that I thought this format was masterful in terms of laying out and laying everyone know what you heard, and that you made your decision. **Response:** Thank you for that, and we’re hoping that since we knew going into this committee that there would be a wide divergence of viewpoints we didn’t want to ask you to sing a report that says this is our committee recommendation. We are trying to be very clear that this is DEQ’s recommendation informed by these discussions. Hopefully most of you agree with many or most of the recommendations even if you don’t like the program as a whole. And we’ve said all along that if there are some of you who don’t think that we should adopt it at all will have an opportunity to weigh in on that once the rulemaking process starts, but we were focusing this committee on what would be the best way to implement the program. We really appreciate the effort and time you all have spent on this committee. It has been really helpful and a great learning experience.

- For the clarify the toxics reduced by biodiesel, can you elaborate on that? **Response:** The PM from diesel is considered a toxic air pollutant. CARB doesn’t recognize any toxics reductions unless it’s created in E20. **Response:** the take home message from this is that we don’t know where we stand yet with the anticipated revisions to the ozone standard and will hopefully know more with regard to any areas in Oregon that might be violating it by the end of this year. If we are violating the ozone standard, transportation is a significant source of precursor emissions for ozone and ethanol can increase the VOC emissions and biodiesel could increase the NOx emissions, both of which could make it harder to meet the ozone standard, and depending on how much of those fuels are used we may have to offset that in other ways in out ozone strategy. So balancing all the environmental affects we definitely need to be aware that the low carbon fuel standard could work against the ozone standard but the effect of that may range from very marginal or nothing to significant.

**Summary of written comments from advisory committee member or alternate November 29, 2010**

- 3B - Farm vehicle and logging trucks - a strange request given that these two industries stand to benefit the most from alternative fuels as feedstock providers. What conditions do they have that are different from others other than cold weather. Blending for cold weather is an important concer to address.

- Short line rail should not be exempt. The switch to cleaner fuels is a one time inconvenience. Short line rail systems consume a very large portion of a metro areas fuel and therefore a very large portion of the local and global emissions. While cold weather lines will need to vary their concentrations of some fuels in the cold months, much of the concerns come from improper protocols when people aren't informed on the transition methods. A one time education effort should not be a barrier to adoption.
5 - Post 2022 should be a lot more aggressive in the reduction schedules. While we MUST allow for a real technology and infrastructure change, the emission reductions that mean the most are the reductions that happen sooner than later.

6a - EXCEPTION: An electricity provider who only provides electricity for transportation and is exempt from Oregon Public Utility Regulation by ORS 757.005 (1)(b)(G) can obtain a carbon intensity number that is different than the statewide average carbon intensity for electricity and specific to the electricity they supply. - Change the word "supply" to "dedicate or purchase for the purpose of meeting the EV load." "Supply" is too nebulous.

6B - Need to put something here that ensures that if the carbon emission reductions of the co-products are attributed to the fuel CI, then there is no other way that they can market those reductions in the channels for the co-products.

6C - Careful to align this with DEQ's definition of waste versus beneficial use. For compliance with the RPS it must be defined as waste. Mill waste and post consumer organics/wood are excellent beneficial use inputs. If they are categorized as waste, it may require a fuel producer to unnecessarily cary a solid waste permit.

6d - This assumption is fine given no timescale. Consider that bio sources that grow on a yearly basis are very different than trees on a 40 year plus cycle. The environmental community will fight any process that allows for large biomass that is on a long cycle. This section should be re-written to accomodate short life biomass and waste biomass only. This will alleviate the concern about "whole logs" as feedstock to energy and fuels and addresses the timescale concerns of a true living carbon cycle.

6E - Next cycle of this platform should include an Energy returned on Energy invested ratio. We can't afford to waste our energy in the name of lowered emissions.

6F - Should state that DEQ intends to implement a carbon intensity factor for land use in 2014. Otherwise it leaves it open for more delay.

6G - if we are considering or implementing indirect land use in 2014, we simply MUST pair this with other indirect effects. Otherwise we are incenting one fuel pathway over another.

7B and 7c are good ideas that will allow for the rapid change in technology and industry.

8 - Stipulate that dedicated electricity can not be zero carbon through offsets. It must be sourced from Renewable sources - reference those power sources that are zero carbon in production and insist on bundled recs. Buying NWPP power and matching recs does not reduce carbon. Recs do not equal negative carbon, just null carbon so adding them to NWPP power still equals the carbon intensity of the power pool.

9A & B - Note that this is VERY different then fuel supply disruptions.

What do we do if the deficits are greater than what the credit holders want to sell? It seems that the only way to meet the compliance bar will be to import very large volumes of ethanol etc from low carbon fuel sources in other countries. While the CI may be known, it may encourage other ecological or social harm to those areas that are not regulated the way they are in Oregon. Likely the deferrals will build up for three years. Then the market will be flooded by imports for a brief moment and then go back to normal.

This will not support innovation in our region. This problem will go away when the production volumes of LCFs catches up to the high carbon intensity fuels. Perhaps we should:

Build in a preference for in state produced fuels somehow.
• Allow trading between states? We could also consider a price cap on credits that would take away the incentive to horde credits and make it mandatory that Oregon generated credits are purchased first. This would de-facto set the market price.
• 10A - this threshold is awfully low. It seems like this is well within market fluctuations.
• 11A - 5% is too low. The price of fuel fluctuates a lot. We can't interfere with the incentive to use less fuel.
• 11B - Exempting a fuel type is a bad idea. Letting deficits accrue is more appropriate.

Summary of written comments from advisory committee member or alternate November 30, 2010
• 2f) Electricity opt-in period should extend beyond 1-year.
• 4) Fully support two baselines—1 for gasoline, 1 for diesel
  o Promotion of low-carbon fuels derives the largest economic benefits for Oregon. Simply substituting diesel for gasoline based on vehicle technology improvements does not yield as many benefits. Oregon needs to develop clean alternatives to petroleum, especially as petroleum will grow increasingly carbon-intensive in the future.
• 5) DEQ should make every effort not to let the compliance schedule slip. Every year that we delay implementation of the program is a year delay in investment opportunities and carbon reductions for Oregon.
• 6a) Carbon Intensities
  o We support the exception for transportation-only electricity suppliers.
  o We support reviewing a statewide average for electricity during the 2016 program review.
• 6h) DEQ should reassess EERs to allow for technology improvements in all vehicle types. The way this is currently written seems to imply there will only be improvements in ICEs, where as efficiency improvements will likely be made in EVs and other engine types.
• 7c) DEQ needs a better method of tracking high carbon crude. This is important for the smooth administration of the program so that low-carbon fuel producers know how large the market will be from year to year, and for the environmental integrity and efficacy of the program. This distinction is very important and has severe environmental risks attached.
  o Reports suggest that tar sand production is poised to ramp up quickly. DEQ needs to closely track these developments.
• 10) Forecasted fuel supply deferral: A 0.1% threshold is too small. At this level, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5% confidence interval, so this number should be at, or just outside that range. This section also needs to allow for the 10% carry over to be factored in.
• 10b) Compliance adjustments: Whenever possible, DEQ should make up for reductions lost in deferrals.
  o Allows bigger market for L-C fuels.
  o Better environmental outcomes.

Summary of written comments from advisory committee member or alternate December 1, 2010
• 2f) DEQ needs to finesse this recommendation. Because there are multiple potential opt-in parties for electricity, there needs to be a way to cycle through so that each party has an opportunity to participate in
the program. However, after that time has expired, there should be an opportunity for any party to decide at any point to participate in the program. Time limitations don’t apply for other fuel types, so electricity should not be limited by a one-year opt-in period.

- 4) OEC fully supports using two baselines—one for gasoline and one for diesel.
  - Promotion of low-carbon fuels derives the largest economic benefits for Oregon. A single baseline would reward a simple substitution of diesel for gasoline—based on vehicle technology improvements, rather than fuel improvements—and does not yield as many benefits. Indeed, the economic analysis did not show any advantage for a single baseline strategy. Oregon needs to develop clean alternatives to petroleum, especially as petroleum will grow increasingly expensive and carbon-intensive in the future.

- 5) DEQ should make every effort not to let the compliance schedule slip. Every year that we delay implementation of the program is a year delay in investment opportunities and carbon reductions for Oregon.

- 6a) Carbon Intensities:
  - We support the exception for transportation-only electricity suppliers.
  - We support reviewing a statewide average for electricity during the 2016 program review.

- 6f, g) Indirect Effects: OEC supports inclusion of indirect effects within the timeframe proposed by DEQ. Indirect effects are real and are important for accurate carbon accounting.

- 6h) DEQ should reassess EERs to allow for technology improvements in all vehicle types. The way this is currently written seems to imply there will only be improvements in internal combustion engines, where as efficiency improvements also will likely be made in electric vehicles and other engine types.

- 7b) DEQ needs to allow for a pilot-scale category that does not automatically regulate facilities at this scale, but does allow an opportunity to opt-in.

- 7c) DEQ needs a better method of tracking fuel sourced from high-carbon crudes. This is important for the smooth administration of the program so that low-carbon fuel producers know how large the market will be from year to year, and for the environmental integrity and efficacy of the program.
  - Reports suggest that tar sand production is poised to ramp up quickly. DEQ needs to closely track these developments.

- 10) Forecasted fuel supply deferral: A 0.1% threshold is too small. At this level, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5% confidence interval, so this number should be at, or just outside that range. This section also needs to allow for the 10% carry over to be factored in.

- 10b) Compliance adjustments: Whenever possible, DEQ should make up for reductions lost in deferrals. This will create a more predictable market for low-carbon fuels and yield much better environmental outcomes.

- 13) OEC encourages DEQ to develop LCFS-specific enforcement actions as soon as possible and to maintain strong oversight of the program.

2. Covered Fuels

December 3, 2009 Advisory Committee Meeting

[Type text]
Best option depends on how the program deals with credits. If the program does not have credits, Options A (electricity, hydrogen, LNG from biogas and CNG from N. American sources are opt-in, all other fuels are regulated) and Option C (same as A, except that biofuels plants could opt-out) would be fine. If the program uses credits, then Option B (all fuels are regulated) looks best in order to ensure that credits are available to buy under the program. Response: An advantage of Option B is that information would be available about the supply of low carbon fuels because producers of low carbon fuels would be required to report. However, they would not be required to sell credits.

Whether opt-in parties decide to actually opt-in to the program depends on whether the trading mechanism is user-friendly, especially in the case of individuals owning electric vehicles. Response: It seems unlikely that low carbon fuel providers will choose not participate, because reporting costs will be outweighed by gains from selling credits. It is important to give incentives for participation, both to ensure credits are available and to lay the groundwork for low carbon fuel availability after 2020.

Even if entities decide to opt-out, they will be subject to the LCFS as consumers of fuel.

PacifiCorp prefers the opt-in approach. Their service area is largely rural, meaning that the costs of installing separate meters and gathering the data will initially outweigh the benefits of selling credits.

Publicly owned utilities find it difficult to take a position at this time without knowing more details, but have concerns about lack of resources for investments and load growth.

Perhaps charging stations could split credits with owners of vehicles, using a something similar to the cardlock system. Response (PacifiCorps representative): In the short-term, it would be more efficient for the utilities to perform the function of accounting for and trading credits on electric vehicle owners’ behalf, but in the long-term a liquid market may be develop that will make it easy for individuals owning charging stations to trade credits on their own. If utilities are forgoing an opportunity to generate revenues, people will bring it to the attention of the PUC.

The gradual phase-in schedule for LCFS argues for an opt-in approach.

Biomass-based diesel has such low carbon intensities that it should be an opt-in fuel. Response (CARB): They included it among regulated fuels because credits from biomass-based diesel are needed for compliance with the LCFS.

Many advisory committee members felt that Option A (electricity, hydrogen, LNG from biogas and CNG from N. American sources are opt-in, all other fuels are regulated) would work, with some reservations about whether biomass-based diesel should be included in the “Regulated” group or the “Opt-in” group. Response: This determination will partly depend upon the ultimate carbon intensity numbers for biomass-based diesels. A discussion ensued about whether participation of biomass-based fuels should be mandatory, with concerns raised that small producers could face reporting costs without a countervailing opportunity to sell credits. Response (CARB): California allows an exemption for low volume fuel producers, because the reporting costs could outweigh the opportunities for some of them. However, they did not find most biomass-based diesels to fit into this category because they are not small volume.

Summary of written comments from advisory committee member or alternate December 1, 2010

Clean Energy believes it is the intent of the DEQ only to regulate liquefied natural gas (LNG) that is imported from overseas to the United States and not blended with otherwise North American natural gas contained in the country's pipeline system (i.e., LNG would be subject to regulation if it is trucked directly to a vehicle refueling station from an LNG import terminal). Clean Energy does not believe this is made clear in the "At A Glance" summary and section describing "lb)". We therefore recommend that
DEQ adopt the following language for fuels "Regulated (compulsory participants) under LCFS": "Fossil LNG that is imported from overseas and trucked directly to a vehicle fueling station without the benefit of blending with North American-based fossil natural gas within the country's pipeline system." We believe the above definition would provide a better understanding of DEQ's true intent under this section.

- Clean Energy supports DEQ's decision to limit the regulation of Fossil LNG to imported LNG that is not blended with North American fossil natural gas within the country's pipeline system as we believe the blending of imported and domestic fossil natural gas will still provide a fuel that will meet, if not exceed, the LCFS' 2022 carbon reduction goals. In fact, North America's abundance of natural gas due to the advances of hydraulic fracturing calls into serious question the economics behind the future importation of natural gas from overseas. Even if LNG is brought overseas and injected into the pipeline, Clean Energy believes such injections will be limited and represent a small fraction of the natural gas supplied to the state of Oregon.

3. Regulated and Opt-in Parties

**January 27, 2010 Advisory Committee Meeting**

- CNG is a currently-existing technology, useful for short “captive” fleets that travel short distances, but economically marginal at this time. The LCFS could tip the scales in favor of making it economically feasible.
- Natural gas utilities are considering ideas to make home compressors more widespread, like leasing them to homeowners.
- Natural gas world has changed drastically over the last 12 months, with many new discoveries. Heavy-duty vehicle fleet owners are especially interested.
- Most common use of LNG is forklifts. They would most likely liquefy pipeline gas onsite. LNG gives vehicles more range.
- California’s LNG filling stations were developed as a network for long-range trucking fleets, tied to the port of Los Angeles. The effort was led by a California clean air agency.
- The equipment is the same as for fossil fuel natural gas, although there could be extra steps to clean it to ensure there are no equipment problems. It’s more difficult to clean methane that comes from municipal solid waste and sewage, compared to dairy manure. Most of this methane is used for electricity generation now. The LCFS could tip the scales in favor of making these kinds of projects more feasible.
- What is included when calculating the carbon intensity of methane from waste? Where are the boundaries drawn?
- Is there an easy way of netting out fuels that come to a Portland terminal, and then are barged to Pasco? **Response (Trucking Association representative):** State economist has a study of fuels bought and used in Oregon and Washington. Perhaps the designation of regulated parties can piggyback onto the fuel tax system. Commenter believes that out-of-state distributors selling fuel into Oregon pay Oregon fuel tax. **Response:** DEQ LCFS team will coordinate with current greenhouse gas reporting rulemaking team to try to make reporting for LCFS and GHGs coincide where possible.
- How it would be handled if a distributor has retail stations on either side of the state borders? **Response:** If Washington and Oregon have similar programs, then we can coordinate.
• Does this proposal track with federal “Blenders of Record” designation? **Response (WSPA):** “Blender of record” refers to producer. For EPA reporting purposes, the refinery reports. That is the level where WSPA prefers reporting to be.

• In case of a retail station getting shipments from out of state, the retail station would be a regulated party? **Response:** This issue has come up for GHG reporting as well. The volume of fuel involved is very small, but some fuel does arrive in Oregon this way. We want to try to make this as simple as possible for small businesses – perhaps an out-of-state distributor could voluntarily agree to be the regulated party in order to make it easier for the Oregon gas stations they distribute to.

• Where the biofuel producer is selling to a terminal, it seems likely that the compliance obligation would shift to the terminal, but that the terminal would pay a premium for the biofuel depending on its carbon intensity in order to get the credits. **Response:** This is correct. However, the biofuel producer would still need to report.

• Why is non-North American natural gas treated differently? **Response:** We know that North American natural gas has a low carbon footprint, but non-North American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.

• It’s possible that someone could deal in LNG, trucking it around to sell as a fuel. Or a fleet owner could liquefy it themselves. In any event, the volumes are likely to be small.

**February 24, 2010 Advisory Committee Meeting**

• There are some practical implementation issues there. Opt in versus regulated. If the regulated entity is always going to be a fuel dispenser, then the fuel dispenser might be a fleet operator. How is he going to know if he is opting in or if he is already regulated, because the portion of the natural gas that he gets from the utility will not go to any of the dispenser, so they are not regulated, but they are the ones that are coordinating the LNG. So is anybody going to do natural gas just by virtue of the fact that LNG makes its way into the natural gas distribution system that just happens to be a customer. Because if the regulating is the fuel dispenser you won’t ever have an opt in. If you want to sell natural gas to transportation because there is LNG in the mix already, aren’t you then already automatically regulating it? Because, I don’t know how you can differentiate that if your point of regulation that the opt in regulation system is the person who owns the dispensing equipment. Because they don’t have control…they don’t have the management control. They are not making the decisions to import the LNG for their fleet operation. So that is why I see the difficulty here in differentiating natural gas, as to whether you are or not. The only way you have a regulated source is if, and I’m just going to throw this out there, Northwest Natural Gas is contracting or bringing imported LNG and NW Natural also operates a bunch of filling stations. That would be one hypothetical. Let’s say they don’t, because I don’t believe they do. Most of them are title partnerships and the partner actually has title to the equipment. What happens with the customer who is receiving that? That is where I see that is the challenge of how you laid this out with the fuel dispensing equipment. I actually like that and I feel that is pretty close to what they will recommend on the electricity side. What is tripping me up is this differentiating between opt in and regulated.

• I can see our fuel dispenser guy could call up his fuel provider and say “What is your mix with North American and what is your mix with LNG?” and then maybe there is a different CI. Then that assumes a mix of those two. And so he is not given as much credit, because there is a greater percentage of imported LNG as part of that. It is almost an analogy of how electricity might work, at that point. What if there is a really lousy hydro year and higher carbon one year, and then the underlying mix is not as low carbon as it has been in the past.
I just want to join the discussion here. So would CNG that was made 100% from imported LNG would it be over the carbon intensity value? Response (CARB): It is possible that it would be very close.

So you might want to say that CNG that was not from North American sources that was not blended in with the pipeline, but that was sold directly as transportation fuel. That is unlikely a very small market, but that particular case would be regulated if it sold as transportation fuel. And then otherwise, if it is blended in the pipeline then I think Kyle is going down the right path. That when the person who owns the fuel dispensing equipment chooses to opt in they are going to get a carbon intensity value that represents the blend.”

Did we want to follow up with the point about if the percentages of imported LNG and the mix goes above some point would that automatically make pipeline fuel regulated as opposed to opt in to the extent that someone is selling it as transportation fuel. I guess there is some point you would have to wonder if it was going to be high enough to be worried about. Or whether the blend always going to be lower than the standard for gasoline or diesel and you just field differently with opt in?

Practically speaking, if an LNG terminal is built and operated at the utilization factors that we are talking about, we will never breach that low carbon fuel standard.

So we agree that there are no objections to this? Then I just want to reiterate Andy’s proposal to make sure there is no objections to that. All CNG that comes out of a pipeline can opt it, any CNG that comes from LNG is not blender into the pipeline is regulated.

So what you are saying is that they are all regulated by low carbon fuel standards because CARB has determined that the LNG uses of carbon are of higher intensity than diesel? How is it that they are regulated from the beginning?

I think there is a fundamental policy question here and that is, do you want to introduce a barrier to the adoption of LNG transit vehicles, for instance. If you want to introduce a barrier to that you will make them regulate it. That is a barrier. It is a hurdle that must be overcome to, and maybe it’s easy and maybe it’s not, but it is a hurdle. So that is the question that you have to ask yourself whether it is regulated or whether it is opt in. Opt in and maybe they get to come in anyway, but regulated you are creating one more layer of difficulty for them in this process, which could be beneficial.

There are 155 gasoline licensed dealers. So you have 155 entities in there and I would guess that most of them, maybe all, sell diesel also. They are different entities than the diesel licenced use fuel sellers.

So what we are saying it those entities would be the regulated entities. That’s what we are saying, for both the gasoline and the diesel.

You would want to reword the regulation to say they are licensed and they are also distributing diesel then they would be regulated.

How would one of these fuel dealers track where the fuel came from and what carbon intensity is? Generally, the fuel is coming from the terminal, and the operators of the terminal get their fuel from import.

Can you can determine the difference between fuel that came from a terminal from Saudi Arabia or from fuel that came from California?

It is not that much an issue for the gasoline itself, because all gasoline will have the same carbon intensity. The issue is of the blend stock, which is going to be the quantity and the type of ethanol.

So they will have that information and you are going to be asking if they know the carbon intensity of the ethanol because of how the ethanol is made. So from California it would be the first producer of the ethanol that would be the regulated entity or importer but not necessarily the dealer who is distributing it.
So that might be a question to think about. Maybe the scheme works for the gasoline and diesel, but not necessarily for the ethanol.

- If you had a high super diesel blend stock, it has to come in and get mixed somewhere and somebody has to have a record of those two parts coming in and giving blend to get carbon intensity numbers of the terminal. So that is really the piece of the import or in production. So it needs to be regulated there before the terminal. Because the terminal is the blending area, right. So you are going to have that large scale then it’s got to be up streamed at the terminal.
- I am sure that none of the fuel distributors know whether or not the ethanol they are selling came from Brazil or Idaho. Very few.”
- Some will know, because because of the value.
- The terminal will know what it bought.

Options presented for biofuels/gasoline/diesel regulated party:

Option A: the regulated party for biofuel or petroleum is the producer or importer
Option B: the regulated party for biofuel or petroleum is the ODOT fuel tax payer

- From our point of view we like Option A. I think you are dealing with fewer parties there. It is where the action is happening.
- Option A versus Option B. Option A digs further upstream. Your original proposal doesn’t necessarily track the taxing and ODOE information and may require the regulator to do something additional that they are not doing right now. Option B, which would have looked more to the 155, are more in line with ODOT taxing and has an ease of use and ease of implementation going for it, but it sounds like it has some difficulties in terms of the bio fuels, or at least a piece of it. How that information be pulled together and recorded.
- Option B is less flexible than A.
- One other consideration is that on Option A level they don’t necessarily know if that fuel is being sold into Oregon or into Washington or somewhere else. Versus on Option B, I think they do know exactly that is sold in Oregon.
- This is difficult. In Option B, it’s based on what is sold in Oregon. And Option A is not. Because something ends up in an Oregon bulk plant or is taken by an Oregon truck doesn’t necessarily mean that it is going to be sold in Oregon. That person could be making a route through the stations in Oregon and in Washington and be all over the place. It is a much greater burden to do the record keeping on that. The reason why Option B for reporting purposes is much nicer is it is easy. If there is any way that we can get whatever numbers that are available on feed blend stock then that is probably the better way to go, with less burden to industry.
- There are two options to explore. One would be to use Option B for gasoline and diesel but not for the bio fuels. I don’t know if that is easy to separate out. But they could go through an Option A approach and the other option would be what Paul said. Whether or not you could go with Option B for everything, but that the terminals would have to get the information on the carbon intensity somehow.”
- The terminals would have to report the carbon intensity content into the dispensed blended fuels.
- They don’t put it in their tanks if they don’t know what it is.
• One of the points I wanted to raise is one of the reason we wanted flexibility in the system is you have to keep in mind that this has to be done in cooperation. These should marry to each other in my opinion. Secondly, we want flexibility, because one of the advantages that flexibility gives us is that an Oregon producers can create a relationship with a user allowing an increase in the level of the bio fuel use. And you want those two parties to be able to trade directly through each other, so there is a potential financial exchange relationship there, an economic relationship there that incentivizes that. So you want that flexibility.

October 14, 2010 Advisory Committee Meeting

• Under the example of a gas station that hires a truck to pick up fuel from out-of-state and deliver it to the gas station, that truck owner has the compliance obligation and cannot transfer the compliance obligation, correct? Response: That is correct, under that option. And in that case the producer out-of-state of that fuel may or may not have transferred the compliance obligation. That’s a private transaction. Response: Yes, that’s right. In this example, the truck owner is not just a commercial trucker, but is a distributor or jobber, and that is the concern. Truckers don’t own the cargo they haul. Response: Correct, so it would be another distributor. The taxes paid on that product is whoever imported the fuel, and in this case it would be the owner of the gas station. They can’t refuse the tax obligation. Response: If the gas station owner owns the fuel as it crosses the border into Oregon, they would have to take the compliance obligation under this option. So are you saying that whoever has the tax obligation is the one that is required to report? Response: There is a little more nuance than that.

• Under the new ODOT rules, if a trucking company takes delivery of the fuel they can then submit the tax to ODOT. Response: Do they own the fuel? Yes, it’s their fuel. This is not a for-hire trucker trucking fuel, this is a trucker that is receiving fuel that is used in their own trucks for fleet use. They shouldn’t be a regulated party. Response: But under this option, they would be. The purchaser can refuse the compliance obligation if they’re not the importer. But who’s the importer? The importer is the petroleum company with respect to the fuels tax, not the entity receiving the fuel. They don’t usually give up ownership of the fuel until delivery. It was never the intention to regulate trucking companies under the LCFS, so I want to make sure that you aren’t. Response: No, right.

• Where you would not have a fuel tax obligation and still be the regulated party? Response: Going back to the nuance, once an entity is defined as an importer, if they own the fuel as it crosses the border into Oregon, they become an importer. This means that they cannot refuse the compliance obligation for any fuel they purchase in-state. So it’s really important how you define the importer. So basically what you’re saying is that you’re trying to discourage rogue importers. Response: In the June committee meeting we discussed exempting small importers but most of the distributors felt that would be unfair, so we are not proposing that. But we are concerned that someone who gets a truckload of fuel would be an importer, so we came up with an option where we created the definition of the small importer who could refuse the compliance obligation for fuel delivered and purchased in state. Response: (Paul Romain) Frank, realistically, how many small gas stations along our border are arranging for their own fuel imports from across the border? Response: (Frank Holmes) I don’t think very many. Response: (Paul Romain) They’re small, which means they don’t make money and they don’t have the infrastructure to do this. So you have a solution in search of a problem. Response: So you see option two as unnecessary. I think you basically say that when you’re bringing the stuff in you’re the regulated party, and basically mirror the ODOT approach.

• There is an option in ODOT’s administrative rules where the importer can pay the tax and the recipient can also pay the tax if they choose to do so, but the importer has to report the import. So as long as the importer is required to report the import, then I’m okay with that option.
Do most of the perimeter stations acquire out-of-state petroleum products through WSPA members? **Response:** (Paul Romain) This isn’t like beer distribution where you can only have Oregon distributors distribute in Oregon. This is petroleum, so you could have a Washington distributor distributing in Oregon, or an Oregon distributor distributing in Washington. If they are distributing fuel in this state they are going to be paying tax in this state, regardless of where they are located.

If a gas station is importing and has a compliance obligation, would we need to have a mirror report from the out-of-state distributor? **Response:** (Bob Russell) They are currently required to report to ODOT as an importer of fuel. You have imports and exports, and the net is basically what gets taxed. So there is a system that is more defined with gas than for diesel because the point of taxation for gas is the rack, and the point of taxation for diesel is the point at which it is put into the vehicle. What prompted the change in ODOT rules was to address situations where fuel is delivered to a farm and the farmer has a choice to either have the tax paid by the outfit that delivered the fuel, or pay the tax themselves. There is then an assurance on the part of the farmer that ODOT is going to treat that diesel fuel as tax exempt on the invoices they send to ODOT. In the past the farmer didn’t have the option of paying the tax, that had to be paid by the importer and if the importer didn’t pay the tax, because the incidence of taxation is when the diesel goes into the truck, then the farmer was on the hook for those taxes. So in order to let the farmer off the hook, they were allowed to pay the tax themselves so that the farmer could provide proof that the tax was paid.

Let’s finish talking about gas before moving onto diesel, because we are confusing the two. **Response:** Actually, we are proposing the same thing for diesel.

So is the farmer an importer under the LCFS program? **Response:** (Bob Russell) You could look at it two different ways, and I need to be sure that we are looking at it one way and not the other. That it’s the person that has the obligation of reporting the import to ODOT, that’s the person who would be the regulated party. **Response:** It would be whoever owns the fuel, so is that the same person? **Response:** (Bob Russell) Usually it is, that’s a contractual thing.

Regardless of whether a truck importing fuel is owned by the purchaser of that fuel, is there a way to tell how many small gas stations on the outlying edges of our state would take possession of the fuel before it was transported into the state? Because that’s what gets at the definition of importer and how many small gas stations would be affected by the definition. **Response:** (Bob Russell) ODOT’s definition is slightly different than what you’re proposing. They are more strict on the definition, because it’s the person that brings the fuel across the border that is the importer. No matter who owns it at that time? **Response:** (Bob Russell) Yes. Ownership is almost always at the FOB destination. **Response:** So then would the definition we’re proposing be workable? **Response:** (Bob Russell) I think so. I just want to make sure that what we’re saying is that anyone that takes bulk delivery of fuel does not become a regulated party under the definition. So as long as it’s FOB, they don’t, but if they actually take ownership out-of-state, then that farmer might be an importer. **Response:** (Bob Russell) Which is why the definition of an importer being proposed for the LCFS is different from ODOT’s definition. I’ve said from the beginning that the ODOT system should be used because that gives you the ability to do your compliance piece in the easiest possible way because ODOT already has all the reports.

It sounds like we don’t need the distinction between small and large importers because the fact that you might become an importer, if you’re a small gas station, you might make the decision to make the transaction in a certain way so as not be considered an importer.

It sounds like most of the smaller gas stations are already receiving fuels in a manner that allows them to not be considered an importer. The gas stations aren’t the problem, it’s the farmers. **Response:** Farmers are exempt.
• Once the incidence of taxation occurs, then it adds another level of complexity that can affect the trucking industry. If we’re using the ODOT definition of importer, then I’m fine. You need to use the ODOT definition of importer. **Response:** Okay. As long as you’re consistent with the ODOT definition, then I’m good with proposed definition of regulated party. **Response:** The ODOT definition is different than whoever owns the fuel when they bring it in. They aren’t doing it by ownership, they’re doing it by who causes the import or export activity. They recognize that the contractual nature of ownership can be different under different circumstances.

• I’m still fuzzy on who causes the economic activity; because the gas station will be ordering fuel, they’re causing the economic activity because otherwise there would be no delivery? **Response:** (Bob Russell) If there’s no customer, then there’s no delivery of fuel, agreed. But the ODOT system doesn’t follow the way you’ve described. They don’t want to get involved in the contractual relationship between buyer and seller. The guy that owns fuel outside of Oregon and is going to sell it in Oregon is the guy that is considered the importer, under the ODOT system. In most circumstances it’s FOB destination so the seller truly does own the fuel, but I could envision a situation where that may not be the case, but in ODOT’s system they ignore that. **Response:** (Paul Romain) The importer is whoever owns the fuel and then causes it to be shipped into Oregon, and that person is responsible for reporting to ODOT for tax purposes in most instances, but there is an option with diesel. So would the gas station who ordered the fuel be the entity that caused the fuel to come to Oregon, or would it be the distributor who supplied the fuel? **Response:** (Paul Romain) Technically, both of them caused the import, so forget the word ‘caused’; the bottom line is if you’re bringing fuel in from out of state, you’re the one who has the obligation regardless of whether you use your own trucks or hire a trucking company to transport that fuel into the state. **Response:** (Bob Russell) ODOT issues licenses and stickers that are different. In the example of a farmer, they would get a users license and sticker which gives the farmer the option to pay the fuels tax themselves. The petroleum provider has a seller’s license and sticker, so it attaches to the certificate. So that’s the answer: It’s the petroleum user or petroleum seller that has the obligation of tax and/or report to ODOT, period. **Response:** So if a gas station received a shipment of fuel delivered FOB, who would be the importer? **Response:** (Bob Russell) The seller, always.

• Is that going to cause some enforcement problems if the regulated party is located out-of-state? **Response:** (Paul Romain) For tax purposes it doesn’t, and it shouldn’t for anything else. **Response:** (Bob Russell) This follows the existing reporting systems. This creates a new compliance obligation for a lot of parties, so that might discourage marketing in Oregon. **Response:** It won’t necessarily be the person that pays the ODOT tax that has the compliance obligation. **Response:** (Bob Russell) Correct, but in most cases it will be. **Response:** Okay.

• Request for committee input on draft economic analysis by Thursday, October 21, 2010.

• Will we see the draft rules in November, or just the final DEQ LCFS report? **Response:** Just the final report with the proposed program structure. At the next meeting we would like to spend some time talking about the last committee meeting and what comes after that in terms of our post-committee vetting process and how you will be given the opportunity to see the rules, among other topics. November’s meeting is when we will address the committee’s request to review the whole program structure. At that meeting we will look at all of the proposed elements together. And December’s meeting will cover anything we haven’t wrapped up in our November meeting.

• In terms of rule timing, will the report be done before the Legislative check-in in February? **Response:** The rules are complicated, and we need to have the benefit of these last few discussions to finalize that, so I think it’s best at this point to focus our energy on the final report and the economic analysis which means the draft rules might lag by a month and that would be part of the post-committee process we will discuss with regard to how we will receive your input. **Response:** (Bob Russell) My understanding from
previous discussion is that the committee wouldn’t see draft rules until sometime next year, and probably not in the first six months. **Response:** Right, not proposed rules, but a model rule that people could see the rule language in addition to the overall structure of the program. Will there be a fiscal impact along with those rules? **Response:** Not in that step. If or when we get to the point of actually proposing rules for adoption, that would include the fiscal impact analysis in our usual rulemaking process. We won’t be able to get all of that done by December, so we want to concentrate on the report and have the model rules probably a month later. If we give the legislature a model rule with no fiscal impact because we’re going to do proposed rules down the road, it seems like they’d be getting half a loaf. **Response:** The economic analysis is part of that package that they will review. **Response:** (Mark Reeve, Chair) The fiscal impact shouldn’t differ from our economic analysis unless the rules are different than what we’ve discussed. **Response:** In our report to the legislature, we’ll have things to discuss that go beyond the economic analysis, such as implementation questions, resource questions, etc. So I imagine our report would be more comprehensive, but would have to include this committee’s report, the economic analysis and other aspects of the fiscal impact of the rule and then we’ll have a fiscal impact statement, but we wouldn’t be proposing adoption at that point. We’ve heard from many people that they would like to see in detail what our draft rule would look like.

- My understanding of this process is that in November we will have the economic analysis report, we’ll get a better view of what the program will look like in December, we’ll have a more complete report to the legislature to show that we’re making progress and what the economic impact of the program is expected to be as it’s being proposed and this update isn’t supposed to be looking for legislative approval but is intended to show the progress being made. And then we will begin the process of EQC rulemaking next summer. What is the target date for that – are we coming up with a proposed rule throughout the Spring and then looking for the EQC to begin the rulemaking process? **Response:** The rulemaking process typically takes six to nine months. So we hope to start the rulemaking towards the end of the legislative session and have something adopted by the end of the year, but we don’t have a rulemaking schedule established yet.

- If we go with what we’re proposing in terms of the compliance schedule, wouldn’t we need to make regulated parties aware of what the rule is by the end of 2011? **Response:** Hopefully the model rule will be what we propose. **Response:** (Bob Russell) The first year would be reporting only, which is 2012, so 2013 would be the first year of compliance? **Response:** That would be roughly the schedule.

- There is some balancing to do in terms of the timing of the fiscal impact analysis because if you do it too early and the rule is modified it can be out of date. **Response:** (Bob Russell) And that’s a very important piece and it almost seems like we are going to be out of step because I agree that until we have a final rule or close to it, it’s hard to calculate those impacts. I think the legislature is going to want some oversight in terms of cost to the agency and budget limitations at some point – when is that point? **Response:** As part of our reporting back to the Legislature in this next session, we’ll talk about implementation of the program, the resources we would need to implement the program, and I think the budget would come from there. I don’t know if it would be in that session or in a following session.

- Will DEQ be asking for legislative approval this session for all the funding needed for the whole program? **Response:** I don’t think so. **Response:** (Mark Kendall) There was a fiscal and a revenue pack submitted with the legislation when it passed and the final report would indicate if there was a wide separation from the fiscal and revenue impact that the legislature approved.

- Is part of the administrative process a requirement that a new fiscal be done? **Response:** Every rulemaking will have a fiscal. **Response:** (Mark Kendall) But that’s a rulemaking, not a statute. **Response:** The rule is not proposed at this point. Mark is right because the EQC could change what is proposed.
• Correct me if I’m mistaken, but my understanding is that the budget provided staffing to conduct the rulemaking, it didn’t provide any staffing to implement a rule. You’re going to need a budget to issue whatever is necessary to impellent the rule. Funds are going to have to come from somewhere, so there is going to need to be some kind of legislative action prior to the time that DEQ implements the rule. The questions is, is that something that you are going to go into the 2011 session with, or are you waiting to 2012 assuming we’d have a special or annual legislative sessions? Response: (Brock Howell) I think this is a question for Andy, so maybe we can get a quick response from him to that question to the committee members. Response: Sure. We will talk about to the legislature about the resource needs to take the program forward. When and how much and if we ask for it, I don’t know.

Summary of written comments from advisory committee member or alternate November 5, 2010 regarding regulated parties.

• If we’re looking at Oregon in isolation, have we calculated in an avoidance factor? Given our aversion to biodiesel at the moment, and if there is a price differential, then there should be an avoidance factor for both rail and trucking, because we are capable of buying fuel elsewhere. Response: (Michael Lawrence, JFA) We can think about that in the change – remember what we provide to the model is dollar expenditures for fuel and if we were to reduce that by some portion we’d have less impact. That could be done but the fuel taxes would still have to be paid to Oregon since you pay taxes on where you drive. Oregon doesn’t have a fuel tax. Response: (Michael Lawrence, JFA) The weight-mile tax applies. Response (ODOT): Oregon does have a fuels tax, however, if the vehicle is over 26,000 pounds then the weight/miles tax is paid. In Oregon you either pay the fuels tax or the weight/mile tax but not both. There are exceptions, like with farmers or split weight vehicles.

• Michael mentioned the only benefits in this analysis are due to the plant construction in-state. With the scenarios being discussed, would this avoidance factor then eliminate that positive impact and add a negative to it? Response: (Mark Reeve, Chair) I thought I heard Michael say that it would be an overall reduction of fuel use potentially, and if truckers that fuel their trucks in Washington drive through Oregon and re-fuel in California, what percentage of fuel use in Oregon it could represent. And that percentage reduction of fuel use would come off the overall gains and losses running through the model, so unless you have a huge plant that is anticipated to be built doesn’t get built, I’d think you would bring down those benefits proportionately. Response: (Michael Lawrence, JFA) I’d have to think about it a little more, but I can’t think of any other. You have to pay fuel taxes in Washington and weight mile tax in Oregon, so that would make it less desirable to try to avoid re-fueling in Oregon. That’s not correct, the tax system is based on where the fuel is burned, not where it’s purchased, so you’re going to pay the same amount of tax no matter what state you’re in. So tax is not a motivator. Response: (Michael Lawrence, JFA) In terms of location of fuel purchase. Correct. While I agree with you that the total amount of fuel we’re talking about is small because gasoline is consumed in much larger quantities than is diesel in Oregon, but it is a significant portion of the diesel consumed. Response: I think it’s an effect they could explore, maybe as a sensitivity analysis of “x” amount of fuel is able to be purchased out of state. You’re missing the point, because at one point we said we’re looking only at Oregon, and now we’re looking at effects of a LCFS regionally. Response: No, I’m not looking at it regionally, I’m questioning whether your scenario of avoidance is realistic when you consider that California already has a standard, Washington is considering a standard, and our indication is that the price isn’t going to be different and so you have a scenario that we could look at sensitivity on to see if it makes a difference. Based on what you’re saying the investment scenario needs to reflect that there is going to be demand for low carbon fuels in Washington and California too because of their standards, which would impact the location of plants. Response (ODOT): This would not be the case as the fuel taxes are considerably
higher in both Washington and California. Fueling in Oregon would actually be a savings. You only pay weight/mile tax on vehicles over 26,000 pounds. Vehicles under that weight are subject to the fuels tax.

- This raises the question of how we’re accounting for compliance. We discussed using the weight-mile tax as the numbers we’d use for the net amount of fuel used in the state, and if we’re using that number to hold accountable the system, then we would have to figure out how that would work. **Response (ODOT):** This is incorrect. As the point of taxation for diesel (use fuel) is at the user level and in Oregon you either pay the weight/mile tax or the fuels tax, this method would only capture the gallons “reported” to MCTD, none of the gallons “reported” to FTG and none of the gallons sold in bulk and never reported.

- If a gas station is importing and has a compliance obligation, would we need to have a mirror report from the out-of-state distributor? **Response:** (Bob Russell) They are currently required to report to ODOT as an importer of fuel. You have imports and exports, and the net is basically what gets taxed. So there is a system that is more defined with gas than for diesel because the point of taxation for gas is the rack, and the point of taxation for diesel is the point at which it is put into the vehicle. What prompted the change in ODOT rules was to address situations where fuel is delivered to a farm and the farmer has a choice to either have the tax paid by the outfit that delivered the fuel, or pay the tax themselves. There is then an assurance on the part of the farmer that ODOT is going to treat that diesel fuel as tax exempt on the invoices they send to ODOT. In the past the farmer didn’t have the option of paying the tax, that had to be paid by the importer and if the importer didn’t pay the tax, because the incidence of taxation is when the diesel goes into the truck, then the farmer was on the hook for those taxes. So in order to let the farmer off the hook, they were allowed to pay the tax themselves so that the farmer could provide proof that the tax was paid. **Response (ODOT):** Not even close for diesel. Diesel (use fuel) is not taxable until it is used upon the roads and highways of the state, therefore, there is no restriction to “importing” diesel in any amount for any reason. Use Fuel “importers” are not required to be licensed under the current statutes.

- Let’s finish talking about gas before moving onto diesel, because we are confusing the two. **Response:** Actually, we are proposing the same thing for diesel. **Response (ODOT):** This is problematic because they are treated differently in ODOT statutes.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- Long-term, plug-in cars powered by renewable energy are likely to be the best technology to reduce global warming pollution from the transportation sector. To make sure that plug-in cars and plug-in infrastructure can take advantage of the LCFS as a market driver, the electricity optin period should extend beyond one-year. In addition, because plug-in cars are likely to improve in efficiency, the EERs for all vehicle types should be periodically reassessed.

- Utility companies should not be eligible for credit generation under OR LCFS. As we noted during the November 16th Advisory Committee meeting, Clean Energy does not believe any "utility company" should be eligible to generate LCFS credits unless it generates such credits through an investor-owned subsidiary that cannot "rate-base" or "cross subsidize" the cost of infrastructure (i.e., a home refueler or charger, public or private CNG/LNG fueling station, public or private electrical vehicle charging station) or the price of fuel (i.e., electricity or natural gas). TheDraft Final Report mentions "utility company" for CNG under Section 2b), for LNG under 2c), for biogas under 2d) and may be inferring a "utility company" for electricity providers under 2f) with the use of "electricity provider". Incentivizing utilities to enter the market for alternative fuel infrastructure through the use of ratepayer funds will create an anti-competitive environment. Private enterprise (i.e., Clean Energy, Trillium, ALT, Prometheus, etc.)
would struggle to compete as such entities do not have the ability to cross-subsidize with profits from a regulated monopoly. Incenting utilities by allowing them to generate credits is likely to limit market development and thus limit the state's ability to achieve its LCFS goals.

- In other words, utilities should not be permitted to participate directly in the natural gas vehicle fuel business, such as NGV refueling, that compete with non-utility enterprises because of the risk that they will engage in anti-competitive conduct (e.g., below cost and cross-subsidized pricing of the refueling services provided to the retail customer). If the holding companies of the utilities want to participate in market activities which result in the generation of credits, they should do so on an unregulated basis with the same terms, conditions and risks facing any non-utility enterprise and without any benefit from inappropriate affiliate transactions with the utility. In this situation, and only in this situation, the non-regulated affiliate of the utility would be the "fuel provider" that would be entitled to receive the benefit of any LCFS credits that are generated as a result of the affiliate's activities which generate the credits. Furthermore, allowing utility companies to rate-base or cross subsidize their costs to provide natural gas vehicle or electric vehicle infrastructure or fuel pricing would not be fair to non-participating rate-payers who would not benefit directly from such investments. Clean Energy therefore objects to direct utility company participation in LCFS credit generation without the use of an investor-owned unregulated subsidiary for CNG, LNG, biogas or electric fueling.

- CNG Opt-in definition of "energyserviceprovider" under 2b). Under the "At a Glance" section of the document and Section 2B on page 55 itself, the "opt-in parties" for Compressed Natural Gas (CNG) are defined as "utility company, energy service provider, or any entity that own the fuel dispensing equipment in Oregon for transportation use", Clean Energy wants to make sure that the DEQ definition of "energy service provider" means third-party fuel providers of CNG. At the November 16th Advisory Committee meeting, it appeared DEQ staff concurred with this interpretation and we wanted to raise this initial concern to you in writing so that staff may further clarify this definition in the narrative.

- LNG Opt: in definition and figures should be further clarified under 2c) to reflect DEQ intent. During the November 16th Advisory Committee, DEQ staff clarified its position on what kinds of LNG processes would be subject to regulation or would qualify for opt-in status. Specifically, DEQ made it very clear during the meeting that LNG subject to regulation would be imported LNG that never enters the pipeline system and is directly trucked to a fueling station versus opt in LNG that is either imported and blended in the pipeline system or LNG that is produced from North American natural gas from the pipeline system and then trucked to a fueling station. Unfortunately, the current definitions under Section 2c) and figures 3 (page 56) and 15 (page 116) fail to clearly make this distinction. Clean Energy therefore recommends making the following changes:

  - LNG from fossil sources -"Opt-in: Any LNG produced from natural gas supplied through a pipeline" Clean Energy supports DEQ's use of the phrase "natural gas supplied through a pipeline" as we believe LNG produced by natural gas from a pipeline anywhere in North America should qualify for "opt-in" status. That said, Figure 3 and Figure 15 could be interpreted to read that such fuel would not qualify for "opt-in" status and would be regulated if fossil-based LNG is produced from the pipeline system outside of the state and trucked into the state to a fueling station. Note that the language used to describe the first phase of four phases for both figures under the regulated pathway reads, "LNG barged or trucked into Oregon". Clean Energy therefore recommends that the first phase of the "regulated fuel" pathway read, "Overseas LNG barged to the US". This modification of the pathway would clearly show the intent of DEQ: to regulate fossil-based LNG that fails to blend with North American natural gas within the pipeline system.
- Clean Energy supports DEQ's decision not to regulate overseas fossil-based LNG if it is blended with North American fossil-based natural gas in the pipeline system. Clean Energy would like to express its support of DEQ's decision not to regulate imported fossil-based LNG from overseas if it is blended in the pipeline system with North American fossil-based natural gas. Clean Energy believes that the amount of imported natural gas from overseas will be small if imported at all given the significant resources of natural gas available in North America. Estimates to date are over 200 years of proved reserves of fossil natural gas based on 2008 consumption levels in the U.S. and this leads Clean Energy to believe that there will be an insignificant percentage, if any, of the natural gas made available to the state of Oregon and the United States from overseas. In fact, since natural gas as a commodity in the U.S. is at $3 to $4 per mmbtu at current market prices and international prices are around $7 per mmbtu, it's hard to understand why imported natural gas would be shipped to US markets under current market conditions.

- Clean Energy urges DEQ to change how it attributes credit generation to "Biogas (CNG and LNG) ". Clean Energy is very concerned as to how DEQ defines what constitutes an "opt-in" party for biogas if the biogas enters the pipeline system. Clean Energy believes that the definition will: (a) slow or kill any viable projects within the state; (b) prevent any potential biogas shipments into the state from out-of-state to help support the state's LCFS; and (c) again float the possibility that a "utility company" can participate in the marketplace, creating an anticompetitive environment with its ability to rate-base and cross-subsidize projects. Specifically, Clean Energy strongly objects to the language found on page 57 of the Draft Final Report on that states: "If the biogas is injected into the natural gas pipeline (this does not occur in Oregon, but it could), the producer would earn and sell the natural gas to a natural gas company. If the natural gas company dispensed a volume of natural gas equal to the biogas they had bought for transportation, they could earn and sell credits for that volume of biogas bought." Clean Energy believes there are several options that the DEQ should consider to ensure that the "chain-of-custody" of biogas would be retained by the biogas producer once the biogas product enters the pipeline.

  - Pipeline Transfer Fees to Retain Chain-of-Custody of Biogas. Biogas fuel producers should have the ability to retain the rights to their product and market and sell that product to the end-user, even when the biogas is injected into the pipeline system by paying pipeline transfer fees. Specifically, if the biogas fuel producer pays the pipeline operator for the transfer of biogas through the pipeline system, this can serve as the "chain of custody" required by DEQ to demonstrate the physical delivery of the biogas to the fueling station. Of course, this option has the downside of adding unnecessary costs to in or out-of-state biogas production and that is why we would urge DEQ to strongly consider biogas swaps.

  - Biogas Swaps. A second option that Clean Energy hopes DEQ would consider over the requirement of paying pipeline transfer fees to create a "chain of custody" would be for DEQ to allow "biogas swaps": the practice whereas a biogas producer contracts the production and sale of biogas to a specific customer without the actual physical transfer of the biogas to that customer. This is a common practice in the electricity market as the approach eliminates the expensive pipeline transfer fees associated with physically transferring the biogas from point A to point B while ensuring the continued production of biogas. The reason why biogas swaps should be accepted is obvious: greenhouse gases that cause climate change are not considered "local pollutants with localized impacts" like criteria air pollutants and the energy swap policies encourage the development of economically viable biogas projects throughout the county by providing carbon compliance to sell the biogas. This ultimately enables the largest reduction in greenhouse gas emissions. While Clean Energy sensed that DEQ would prefer to have a system that could physically demonstrate the transfer of biogas to a fueling station, DEQ should be aware that this adds a significant premium to the cost of producing perhaps the lowest carbon fuel available on the market today and could actually make
some biogas production projects economically infeasible. This is not an outcome or hurdle that Clean Energy believes DEQ would intentionally want to establish. Further, not allowing biogas swaps also creates an unfair advantage of electricity over gas. If it would be useful, Clean Energy would be more than happy to work with staff to create this option for future biogas sales that would support the Oregon LCFS's goals of a 10 percent carbon reduction by 2022.

- Clean Energy believes it would be helpful for DEQ to better define how a party would qualify as an "opt-in party" for CNG, LNG and biogas (CNG or LNG). The Draft Final Report, as it is currently written, is virtually silent on this detail and Clean Energy believes that it should be defined so that it is clear under the LCFS who is actually generating the LCFS credit for fueling a natural gas vehicle (NGV). Clean Energy, therefore, urges DEQ to consider how the California Air Resources Board defines each of the respective parties as each fuel (CNG, LNG and Biogas) has their own distinct process or pathway.

- Specifically, natural gas on its own is not a vehicular fuel. It either needs to be compressed or liquefied before it can be used by a natural gas vehicle (NGV). The California Air Resources Board (CARB), with this understanding of the NGV Industry, decided to define the "opt-in" party for each fuel as follows:

  - CNG: The owner of the fueling infrastructure that compresses the natural gas.
  - LNG: The entity that delivers the LNG to the fueling station.
  - Biogas (CNG or LNG): The producer of the biogas.

- CARB defined the "opt-in party" for these various forms of natural gas to identify the party that actually "enabled" the fuel to be used in the vehicle. For CNG, natural gas needs to be compressed. The party that invests the monies to create the infrastructure to compress the fuel should rightfully take the LCFS credit under the LCFS program. For LNG, the physical delivery of the fuel to the LNG fueling station is the enabler and therefore defines the "opt-in party". As for biogas (CNG or LNG), this should favor the biogas producer to remove any barriers that could be created by diminishing the profitability of biogas production. Clean Energy will provide CARB's exact language to DEQ as an appendix to these comments.

4. Exemptions

November 3, 2009 Advisory Committee Meeting
- Non-road fuel is not as available as many farmers would like. Some have to drive 30 miles to buy it.
- Most gas stations have two underground tanks, one for premium, and one for regular. Mid-grade gasoline is produced by blending the two. Some stations have a third tank for diesel.
- The approval process for new tanks is said to be longer than two years.
- Railroads are said to use the same fuel as trucks as both come from the same supply.

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- If producers less than 10,000 gge equivalent are proposed to be exempted, and that is the volume of the smallest producer, then no one would be exempted. **Response:** That is a suggested starting point – the
idea is to give the smallest producers time get up to production volume before being regulated. DEQ is open to other suggestions.

- Need to consider barge system, towboats, etc.
- With regard to intrastate locomotives, the definition of “intrastate” has to do with where the shipment is going, not where the locomotive is going. So a truck could be transporting wheat to a silo, which then gets put on a train out of state. That truck movement, although never leaving Oregon, is interstate commerce because the wheat is destined for out of the state. Some trucks are captive and will fuel in Oregon, but 90 percent of trucks registered in Oregon are engaged in interstate commerce and could probably fuel elsewhere. **Response:** What DEQ is concerned about is the fuel, not the goods that are being shipped. An interstate locomotive is likely to fuel outside of Oregon, as could the oceangoing vessels. DEQ will look into the definition of intrastate railroads. Farm and log trucks are exempt, but the truck owners themselves would not be subject to the LCFS. What is important is that the fuel they use is exempted. So we’re not talking about exempting the interstate locomotives, but the fuel they use. The question is about the fuel and the fueling system and can the fuel be supplied separately.

- If you are regulating at the blender level, how will you separate that out?
- What about fishing vessels? The entire fleet is legacy. Should we consider granting them the same considerations as logging trucks?
- Commercial construction equipment, off-road equipment fuel is supplied in two ways. Some companies own their own equipment, others rent. So when you’re talking about this in relation to the construction industry, it is very complex – some are small businesses. **Response:** This regulation is for the fuels, not the equipment.
- But all of the construction equipment doesn’t get capitalized very often, and what kind of retrofit or new equipment would need to be purchased to use the fuel? Some portions of construction equipment fleets have specialized uses. Even though it doesn’t use different fuel, it needs to operate well. **Response:** The statute requires that any biomass-based diesel or ethanol meets fuel specifications enforced by the Oregon Department of Agriculture. On-spec biodiesel should be able to function in any engine.
- Part of the statute says the rule has to be feasible. Truck manufacturers will only honor warranties with five percent biodiesel or less.
- Of the fuels for which exemptions are proposed, some are outside DEQ’s jurisdiction and some are specialized fuels that have their own specifications.
- Currently, we have an Oregon Renewable Fuel Standard requiring B2 (diesel blended with two percent biodiesel) is being distributed. We have an avenue for off-road fuel to be clear, and we have clear aircraft fuel already. For people concerned about the effect of a LCFS, what are you doing now? You’re either using a clear off-road product, or you’re using B2. Hence, potentially low carbon fuels are already on the market and people are using them.
- Why didn’t DEQ propose to exempt all off-road? Airport and ground support or port equipment is not exempted. All of those fuels will need to use fuels that meet a LCFS spec. If that is the case, then those technologies become candidates for electrification or natural gas. In California, there are existing regulations that address this equipment, and they are working on sorting out the relation to the LCFS. In Oregon, we do not have regulations that address this type of equipment.
- Recreational boats are exempt from the Oregon Renewable Fuel Standard for a good reason. It’s not a large amount in terms of quantity, but you might want to be consistent with the Oregon Renewable Fuel Standard.
• The regulated entity is the fuel provider, and not the fuel consumer, so these fuels should still be provided. It’s the provider’s obligation to balance the fuel mix, so there is a potential to provide for some of these consumers while making reductions in other areas. So the LCFS is not a wholesale change in the fuel mix.

• Right now farm operations use the same fuel as truckers and the construction industry. This exemption was given to the farm industry, and it seems not to mean anything because fuel providers might not maintain a separate fuel supply for the agricultural community. Maybe in some areas it might be available because out-of-state suppliers will still be bringing in fuel.

• Exempting all non-road fuel would be appropriate to ensure that fuel distributed to farm vehicles is functionally exempted from a LCFS. It is widely held that fuel distributors minimize the number of fuels they provide to reduce cost and simplify operations. Therefore, relatively small volume uses (such as farm vehicles) may get low carbon fuels regardless of exemptions. Furthermore, a LCFS has the potential to increase use of biodiesel making fuel more expensive or causing performance problems. Response: Because exemptions dilute the overall effectiveness of a LCFS program, they should be used only as actually needed. LCFS fuels still need to comply with established fuel standards.

• Throughout the passage of this bill (House Bill 2186) and in hearings the agricultural community heard that this would have no impact because of the exemptions. It’s frustrating that this does not appear to be the case because the fuel suppliers will not be supplying clear fuel.

• Are agricultural users today getting clear, off-road diesel fuel? Yes, either dyed or clear, depending on the amount of fuel they buy. To buy clear fuel, they have to purchase a whole truckload, and there is only a small segment that can do that. The concern is the cost and availability and what the LCFS means to their business.

• If the agricultural community is getting clear fuel now, the LCFS should not affect that.

• Is it the price or perceived performance issue? During the session, the concerns were raised because of the price.

• When ULSD first became available, the Port of Portland wanted to require ULSD as a pilot project for one construction project, and there were major concerns that it would cost more, etc. It turns out that it did not cost more, because of the large supply. The more these low carbon fuels have to become a specialty fuel due to more and more exemptions, the more they will cost. There might be economies of scale if there are fewer exemptions.

• What is the nature of the burden to agriculture? If agriculture is already using fuel that is highway grade, that means they have made the fuel filter switches and the commenter doesn’t understand what the cost risk would be given that the fuel would be available ubiquitously, and the cost would not be more.

• The concern is what happened with the move to 10 percent ethanol – there were significant impacts to not just the agricultural sector. We need to look at the exemptions from the Oregon Renewable Fuel Standard, because there were significant costs, not just to agriculture. Costs of engine failures, new carburetors and retrofitting because engines can’t run with ethanol. The agricultural industry runs on older equipment and vehicles. B2 (diesel blended with two percent biodiesel) is a low percentage blend, but as we move to a higher percentage – current warranties allow for five percent biodiesel, but older vehicles do not have that consideration.

• But haven’t they already borne that cost in the switch to ULSD? ULSD, with its higher solvency, has already cleaned out all of the tubes, so what is the additional cost?

• I think the ULSD is only on clear and not red at this time. Is there going to be with LCFS, a new change, such as a higher blend or something else that would have an impact on older engines.

[Type text]
• So that is question for DEQ – is the fuel more problematic as it gets purer? This is a discussion not just for the agricultural community, but for all users.

• So far, there has been nothing but anecdotal evidence presented on the cost of increased biofuels use. Do any advisory committee members have any actual evidence or studies of greater cost or problems due to increased biofuels use?

• One member stated that federal rules require locomotives to be retrofitted in future years to reduce emissions of Volatile Organic Compounds, Nitrogen Oxides and Particulate Matter. He indicated the use of biodiesel in upgraded locomotives would nullify the equipment warranty. Response: DEQ will investigate this issue.

• One potential solution regarding agricultural fuel use (it wouldn’t solve the whole issue with the exemptions) is that the farm coops are a large fuel buyer and they they already keep track of agricultural use of fuel for tax purposes. Some also have fuel sales to cars, but can separate out that documentation. Although, off-road fuel is not tracked for tax purposes. Could the rule be written around this existing documentation? Response: Yes, the criteria are that the exemptions would need to be verifiable and traceable. DEQ suggested one way to achieve that end would be for final users of exempt fuels to provide simple statements of exempt use. Such statements would be aggregated by regulated parties and their total volume would be subtracted from compliance calculations.

• For bridge construction projects that required fuel tracking, it was easy to get fuel information from a fuel supplier. It’s just an accounting protocol for the fuel supplier, and is easily traceable.

• Other members also expressed concern that a LCFS would cause problems with legacy vehicles or niche uses such as sailboats (in which fuel for auxiliary engines can remain unused for years). On the other hand, one member pointed out it is likely such vehicles are already getting biodiesel; another thought any problems would be temporary and limited to clogged fuel filters.

• The committee also discussed whether exempt fuels should be allowed to earn low carbon fuel credits. Allowing such credits could provide an incentive for low carbon fuels when they are not mandated and provide flexibility in meeting a LCFS standard. Not allowing such credits could discourage the use of biofuels beyond what is already required by renewable fuel standards (in response to concerns that greater use of biofuels in exempt categories would cause problems).

• What percentage of biofuels is likely to be required? The advisory committee would like DEQ to provide information.

• Some agricultural users have been using higher blends of biodiesel, and love it.

• LCFS does not require biofuels to be blended.

Summary of written comments from advisory committee member or alternate January 15, 2010 regarding exemptions

• There is an exemption for interstate rail but not interstate barge. There are several operators including Tidewater on the Columbia and Snake river system that operate interstate as well as our harbor boats that are strictly intrastate. My question is was there any thought given to the possible perception of a competitive advantage afforded the interstate rail companies which just happen to be our biggest competitor?

Summary of written comments from advisory committee member or alternate June 17, 2010

[Type text]
On revisiting exemptions, I see the exempt parties and/or fuels of low market volume pretty well addressed in earlier discussion and decision. Given the magnitude of the influence of any exempted fuel or opt-out of provider on either the near term fuel carbon content or overall accomplishment of the LCFS, I see that as an edge discussion. We simply want any rule adopted not to provide permanent exemption for any fuel or provider or regulated entity, but to simply provide a vehicle for it to be administered by staff. We want to reserve rights in any case to remove exemption for various and obvious reasons.

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- Unless you can demand a huge amount of volume, don’t expect to get non-blended stuff. And that is where the exemption thing is going to cause some political troubles down the line because the folks who are exempt thought that they were going to get non-blended stuff.
- Interstate locomotives are currently getting non-blended fuels because they represent 2 million gallons of demand where the trucks are getting the mandated 2% biodiesel. The locomotives probably won’t have a problem getting non-blended in the future.
- How does this fuel exemption certificate functionally get from the user to the supplier that they can then use that to take into accounting for their credit? **Response:** There is no certificate. Regulated parties will track how much fuel is sold to exempt parties and that volume is not used in the calculation of meeting their LCFS compliance obligation. The documentation of that sale should include a statement that it is being used for an exempt use.
- The 360,000 gallon equivalent what is that percentage rise for the volume in Oregon. Is that like 1% or 1/10%?” **Response:** There is basically 2 billion gallons statewide, approximately.
- The marine exemption does not apply to all other watercraft and that didn’t seem to be what you said when you discussed it previously. Did that change for same reason? **Response:** the exemption is just for ocean-going marine vessels. All other watercraft uses are not exempt.
- Water craft are exempt from the ethanol requirement. But if they are not exempt from the LCFS, so they could get a blended fuel that they don’t want. **Answer:** The marina could still provide the appropriate fuel to that boat, but the ultimate regulated party would have to make it make it up by selling more low carbon fuel elsewhere or buying more credits so the net balance works out.
- The problem is with the language. Saying that possession of the fuel is the key in meeting the LCFS is wrong. That has nothing to do with it. They can have whatever fuel in their boat, in their logging truck, or whatever. **Response:** Yes, that is correct. We will work closely w/ DOJ to craft some language that would apply more broadly but still specifically refer to the exempt uses.
- DEQ should consider that consistency with the RFS is something that regulated parties would like to see. I.e. exempting water craft. This is not a technical issue, it’s a political one.
- For any type of federal reservation I assume they are exempt. **Response:** They are not exempt except for those uses specifically called out in this section of the rules.
- Shouldn’t we exclude these exempt groups from the sectors that are included our REMI model? **Response:** Even though the fuels are exempt, there may be other economic impacts to these sectors so they should remain in the REMI model.
- I would strongly advise as our job as the advisory committee, knowing this process and going through it in California, making it clear up front as soon as possible about who are the regulated parties in this
program. Right up until the end I kept going into CARB and saying “You are not regulating me right? You’re not regulating me?”

- With propane, if we switch from diesel to propane, can we get credit it for that even though it’s exempt? **Response:** Propane is exempt from this program, which means that fuel distributors can’t get any credit from selling propane. Propane did not want to be a regulated entity and they would have to become one if they wanted to sell credits. We can look into whether we could write the ability for them to opt-in and then if they opted-in they would have some reporting obligations. As long as they are okay with it I think it would be beneficial to the program.

- Six months ago, when we first talked exemptions I was basically told to wait until later in the process. Is now the time? For the economic impact analysis, is it going to be about fuel prices only? Is it not going to be about whether a whole fleet, in my case the legacy fleet/construction industry, can make happen what is going to be essentially a mandate by the fuel producer to use more low carbon fuels? It would appear to me, that there is no place in this process that an industry like mine to know for sure what is going to happen. That is why you are doing an economic impact analysis, right? It seems that we are not going to drive down deep enough to help some industries understand or help you understand what the impacts could be on industry. Am I missing something here? A whole number of industries and a big part of this advisory committee’s job is to try to understand the implementation of this program and I’m not seeing the place where that is going to happen. **Response:** The economic analysis is going to be looking at all sectors. It is going to provide a lot of good information for you to see what we anticipate the cost of fuel is going to be and the availability of fuels and what kind of demand there might be for, in particular, on your sector. Let’s see how it comes out and then let’s revisit it.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- Small producers of low carbon fuels are exempted from regulation under the LCFS as recommended by DEQ. ZeaChem supports DEQ's recognition of both individual small producers less than 10,000 gallons gasoline equivalent (gge)) and total aggregate volumes of low carbon fuels under 360,000 gge to ease the burden of introducing new fuels into this highly competitive market. However, ZeaChem is concerned that the exemptions outlined do not adequately account for pre-commercial scale production facilities, such as research and development and demonstration scale, which are needed in order to verify a new technology prior to commercial production.

- Recommendation: The language surrounding aggregate volumes is vague as it specifically applies to ethanol. The report recognizes the important role of ethanol as a low carbon fuel including current first generation corn ethanol and advanced cellulosic ethanol production. In the proposed aggregate volume exemption, DEQ should indicate that cellulosic ethanol is a separate, distinct fuel group from corn ethanol since the state already has production levels of corn ethanol well in excess of 360,000 gge aggregate volume. By creating a separate fuel group for cellulosic ethanol, the DEQ will recognize the advancements being made in the industry based on different feedstocks and novel technologies and processes and ensure that small volume producers of cellulosic ethanol are exempt.

- Recommendation: In addition to the above proposed modification to the total aggregate volume language for ethanol, ZeaChem respectfully submits to DEQ an additional exemption category for research, development and demonstration facilities. This additional exemption allows novel pre-commercial technologies to be established in Oregon without additional regulatory burden, thereby promoting future commercial scale production of low carbon fuels in the state. On November 23, 2010, the Oregon Department of Energy (ODOE) published the new permanent rules for the Business Energy Tax Credit (BETC) program. Included in the final rule is a definition for "Research, Development, and
Demonstration Facility (RD&D)." In order to simplify state policy and regulation impacting pre-commercial scale facilities, ZeaChem recommends that DEQ include the ODOE BETC definition of RD&D facilities as an additional exemption to the LCFS. (See: OAR 330-090-0105 62(a)(A)-(C), available at: http://oregon.gov/ENERGY/CONS/BUS/docs/BETC_Rules_112310-Final.pdf.

5. Setting the Baseline

January 27, 2010 Advisory Committee Meeting

- The 2007 data is fine to start with and for DEQ to use for its analysis, and the Energy Information Administration data is widely reported although not perfect. As we get closer to developing the rule, we can see if 2008 data are significantly different than 2007.
- Why not use 2008 data if it’s available in July? **Response:** DEQ and its contractor need to go ahead with compliance scenarios and economic analysis before then.
- Considering 2007 versus 2008: In 2007 the economy was strong, so demand for oilsands as the marginal, most expensive resource, should be higher than in 2008 when the economy was weak. That would make 2007 a conservative baseline with regard to carbon intensity.
- Do we give fuel providers credit for blending ethanol into premium gasoline, if it’s considered “exempt” from the state RFS?
- Commenter prefers not to include biodiesel in the baseline. Biodiesel blending was not required under state law in 2007, which is the year we’re likely use for our baseline data. Would like to get credit for what we’ve already done. **Response:** We should include biodiesel at the 2010 required blend rates if we’re trying to reflect what will actually be in the market in 2010, which includes B2 statewide and B5 in Portland (Portland reports sales of 15 percent of state diesel market).
- We shouldn’t simply reward existing biofuel use. Biodiesel should be included in the baseline.
- The legislation says 2010, not 2007. Conversation ensued about how to interpret the date set in statute, whether it simply refers to the start of the program or to the actual data that must be used to set the baseline.
- Perhaps the program should require zero reductions until 2010 data is available, or should make it clear that ultimately regulated parties will have to true up to a baseline based upon 2010 numbers. **Response:** We have to start somewhere, and 2007 is what’s available now.
- Will the baseline be used to figure out what regulated parties have to do year-by-year, or simply to set the 2020 goal? If the baseline is used to set the 2020 goal, then making midterm adjustments once 2010 data is available is not as big a deal.
- It seems like we’re talking about really small changes, while indirect land use change is going to dominate over the difference between 2007 and 2010.
- It makes sense to leave out small volume fuels when setting the baseline (for example, electric cars, blends over B5, etc.).
• Fuel-switching almost guarantees a new vehicle, and new diesel controls are stricter, so not that worried about increased diesel particulate pollution. Don’t want to encourage dog fight over natural gas supplies between transportation and electricity generation.
• Commenter prefers one standard, and agrees that co-pollutants from diesel are not an issue. Light duty diesel is an improvement over gasoline.
• Oil industry prefers one standard, based upon new numbers from CARB on carbon intensity of soy biodiesel which is not much better than petro diesel.
• Commenter does not get the point of two standards, concerned about creating silos. **Response (CARB): If you have one standard, then once you take into account efficiency of diesel vehicles, regular diesel will generate credits without doing anything to improve its carbon intensity. Those credits could be applied toward gasoline, and gasoline would not have to make many improvements either. If there are two standards, improvements will have to be made on each side. Credits from each can still be applied toward compliance for the other fuel category. Acknowledges there are concerns about the lack of enough low carbon diesel alternatives. Even if the carbon intensities for gasoline and diesel are the same, if you apply an EER to diesel, then regular diesel will comply with the LCFS and you will get zero reductions from the program.**
• Biggest contribution of the LCFS is stimulating innovation in the fuels market, so we want to make sure the program we design does that.
• We have high benzene content in our gasoline, so switching to diesel is not a big concern.
• Carbon intensity of soy biodiesel is a big compliance concern for oil industry.
• Oil industry representative stated that diesel vehicles travel approximately 30 percent farther for the amount of carbon emissions generated.
• Switching more of the light duty fleet to diesel would have an immediate effect on carbon emissions. Reducing emissions in the short run is more valuable than in the long term. Two standards will delay the reduction in emissions, which makes the reductions worth less.
• How will electricity providers track when electricity is used to displace gasoline and when it displaces diesel? It would be easier for them to have one standard.
• Andy Ginsburg pointed out that Oregon is much smaller than California, and has much less chance of stimulating innovation in fuels, so perhaps other factors, such as avoiding complexity, should drive Oregon’s decision about one versus two standards.
• Commenter expressed preference for two standards, but sees that benefits will also come from one standard.
• Commenter expressed concern that one standard will allow credits for what regulated parties are already doing, causing lower benefit from the program. **Response: Baseline could be set to ensure that there is no credit for existing diesels, only for new users of diesel.**
• Andy Ginsburg asked whether committee was comfortable with a tentative consensus that they preferred one standard, but with plans to re-examine the issue once they have seen compliance scenarios.

**Summary of written comments from advisory committee member or alternate June 17, 2010**
• The legislative intent is to reduce carbon content in Oregon's roadway transportation fuels. That is plural. Setting two baselines provides equal incentive for diesel and gasoline to progress. One baseline obfuscates the differences between the fuels, the potential(s) for each to lower their carbon content and creates an environment where fuel choice may be as attractive as improving our fuel base carbon
performance. Although more choice of distillate fuels and compression engines over internal combustion will reduce carbon dioxide emissions, it is a benefit that is in addition to the objectives of the LCFS legislation. We should use two baselines to be specific about our hopes and targets for each fuel. Using the EER and tracking gasoline conversion to light duty diesel is rife with data collection efficacy issues that we shouldn't base public policy accomplishment on. We are treating each of the alternative lower carbon fuels independently, we should do the same for base fuels. The complexity of administering a two base approach will not that difficult to do and drives innovation in each fuel. Option 3 will yield the best outcome for lowering the carbon content in each fuel. If we want to reduce carbon dioxide emissions from fuel us, then there should be an approach that encourages of incents diesel use over gasoline as long as PM et. al. is appropriately addressed and that should be separate from LCFS.

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- People are buying light-duty diesel vehicles. There is fuel switching from gasoline to diesel. **Response:** Right, and it would be appropriate to apply a diesel EER to the switches from gasoline to diesel.

- The new SCR technology for light-duty passenger diesels results in diesels that are almost as clean if not cleaner than gasoline. The concern about diesel for more toxic air pollution is one of the things that is happening now with the latest rule making in California Level 3. The phase in starts at 2014 and will be fully phased in about 2020 in Oregon.

- Gasoline has benzene, so any toxicity in diesel makes the issue a wash.

- Fuel suppliers would like the flexibility of encouraging fuel switching to diesel to meet the standard, rather than having to blend low carbon biofuels or purchase credits. This might reduce the innovation for low carbon fuel.

- For tracking light duty diesel fuel use, use the Cost Allocation Study. It is a model that predicts how much revenue is going to be produced from various classes of vehicles.

- Individual companies are going to have to show compliance with the low carbon fuel standard based on the volumes of diesel and gasoline that they sell. They will generate a certain amount of deficit relative to the standard, and will have to generate credits by blending biofuels or buying credits from other low carbon fuels. So if we have general data that we know this number of diesel passenger vehicles were sold in Oregon in a given year. First we have to figure out how many of those would have been sold anyway and how many are as the result of fuel switching so they represent a reduction in gasoline. And then we have to figure out who gets that credit, individual companies?

- If you look at the fuel not the cars, from the individual producers point of view, you can certainly provide that data on the ratio of gasoline to diesel. **Response:** the change in ratio could happen because of fuel economy on the gasoline side, the diesel side, a change in market share, or fuel switches from gasoline to CNG or some other fuel.

- There are fuel economy standards, at least for heavy diesels. **Response:** A change in the fuel economy standards for diesel (or gasoline) could mask the effect of fuel switching and companies would not accurately receive credits.

- What we are suggesting is that diesel is viewed as both as a regulated fuel and as a low carbon substitute for gasoline. **Response:** Yes.

- For gasoline, if it were possible to track it I think that is what we are suggesting. We are trying to see if there is a mechanism that would actually work, or are we going to end up basically providing credit for something that is not really occurring but is actually just masked because of fuel economy improvement in gasoline vehicles.
• Someone switches to an E85 vehicle, so goes from gasoline vehicle to an ethanol vehicle. What then? **Response: There is no change in the EER because it is the same kind of engine as gasoline.**

• Why is the reason for the switch relevant? You should just keep it at the fuel supplier level. The goal is to get more low carbon fuel out there. The reason people are switching is irrelevant.

• Here is an extreme example just to illustrate the point. In a future year we had absolutely no growth at all in the amount of gasoline vehicles. They stay stagnant, and fuel economy doesn’t improve. The amount of gasoline sold stays constant and the amount of diesel that is sold goes up because there are more people and they are buying new cars and all the new cars are diesel passenger vehicles. And so what has actually happened here is just that we have had growth in the amount of vehicles and we have had no improvement in greenhouse gas emissions, but our program having not been able to capture that difference gave credit for all the growth in diesel use and made it appear as if we had reduced greenhouse gas emissions. But nothing had happened, other than population increasing in Oregon. That is an extreme example.

• If you relatively lessen greenhouse gas emissions, but you have more vehicles on the road, but the level remains the same. Relatively, you really have reduced it.

• Not if you are assuming that the diesel vehicles are replacing the gasoline vehicle, which I think we are assuming. We assume that the diesel vehicle replaces the gasoline vehicle.

• The easiest way to reduce carbon emissions is to use efficient fuel. We should encourage fuel switching.

• You want to get credit for that in the right way and I think that is the key. How do you give credit for that in the most accurate way possible? And the dual baseline may actually do that better.

• The duel baseline doesn’t encourage fuel switching. It would be a benefit if we could approach the percentage of diesel passenger vehicles in the fleet such as in Europe.

• How do you parse out the credits to the individual supplier of diesel?

• I would hate to see that issue hold us up from doing something that is beneficial. **Response: You can’t separate out growth from fuel switching. If we set up the program like this with no way to track clearly how much of increased diesel use was as a result of reduced gasoline use and how much was as the result of just growth. We would be providing credit for increased overall use of fuel as opposed to reduction in emissions.**

• But I think you can discreetly analyze cars, which are 10,000 lbs or less, medium duty or heavy duty separately. So once you recognize that you can, say this is what is happening in 10,000 lbs and under category today that is your baseline. And you can see what happens in the future. I think you can do the same thing with the suppliers. I don’t think you look at the vehicles. I think it’s a low carbon fuel standard and you look at the fuel. That is what you are measuring. You are not measuring the number of vehicles. You are measuring the amount of fuel. So if you see an increase in the amount of diesel fuels sold how do you tell how much of that is from growth in total vehicle travel and how much of that is from fuel switching?

• You would be able to see the difference in the ratio, which is what you have in the slide right there. **Response: that slide is the list of things that will not work.**

• The ratio will be affected by fuel economy changes. As gasoline cars become more fuel efficient due to the new Café Standards, the ratios change

• You calculate the impact of the Café Standards, both for gasoline and diesel, because you know the turnover of your fleet, how long it takes for it to turn over, so you know what percentage of your fleet would be in compliance with the new standards versus the old standards. **Response: If you were able to**
do that you still couldn’t attribute it to an individual regulated party. I don’t want you to get the impression that DEQ doesn’t want to make this work. We would love to see if there is a way to make it work. We just haven’t been able to figure it out yet. We have gone through the same mental exercise and if we can figure it out. If there is a way for us to implement it and be actually able to track the credits we are open to it.

- If you have 100 vehicles on the road today and there are 20 diesel and 80 gas, and ten years down the line you have 150 vehicles on the road and you’ve have added 50 diesel and no gas, that is a positive thing. Your ratio is lower. So, why are you having a problem in saying just stay with the fuel? It’s okay, we are implementing the low carbon fuel standard, because in effect there is less carbon out there, because people are switching fuels and you can track it simply at the fuel supplier level when you regulate.
- Would the supplier be able to tell us how much light duty diesel they sold to light duty applications?
- They would be able to tell you how much they sold to a gas station.
- You answered my question that I was going to ask you and that is from the rack going out to the stations if that fuel supplier will know where that fuel is sold, light duty versus heavy duty, in a gross percentage. And those would be the people who would be looking for the credits, who would want to do the accounting to get that credit. You have the registrations of the vehicles. We know what the fleet fuel economy is going to be and you can basically do a calculation of what your overall fuel economy is based on vehicles registered.
- That’s where you are trying to do your accounting for the greenhouse gas in the atmosphere. The oil industry is looking to figure out what is there in credits that they are getting. And maybe you change that credit amount or value every two or three years. But you can come up with what the fleet looks like and you can come up with what the percentage of gasoline versus diesel. And then you can value how much that additional diesel is.
- It’s not exactly right, because you are going to have a statewide average for where the vehicle fleet has gone, but what you need is that at the individual transaction level so that way you know that the vehicle is sold to what type of vehicle or vehicle that was in. And all you know is the statewide average. You don’t know whether the transaction was to a fuel switch.
- Well there is a gross assumption that you have to make in all of this stuff here. If you try to save us the CO2 emissions from each one of these cars, you might want to do that. Obviously, if we could monitor the CO2 output of every car that makes all of this easy, but you have to make a few assumptions along the line. And I think you make the gross assumption of what the average fleet is in the State and then you know what the amount of diesel that is being sold versus the amount of gasoline. If what is going on Europe is any indicator it is going to be pretty significant. What I’m hearing from the majority of manufacturers is they are talking 30-40% diesel introduction in the next couple of years because of the fuel economy standards. You are laying curves on top of curves. It is not a flat line that you are going to see change. You have a fuel economy standard that is going to increase and now you are trying to adjust off that adjustment.
- This single baseline seems to violate two significant principles that we operating under. 1) we want a system which promotes innovation. We’ve understood that that is a compromise here of the single baseline. 2) administrative simplicity. It needs to be workable and this is like grabbing something here and making assumptions and tracking this, and simplicity is the only way this thing is going to work. I think we should go through the other scenarios and options and see how they really look and how the impacts may affect these considerations.
- At the federal level, the President has put into effect Executive Orders to increase efficiencies for not only light duty vehicles for the years 2012 through 2016, but also to go beyond that and also look at
medium and heavy duty trucks. The low carbon fuel standard is intended to shift the market away from high carbon fuels to low carbon fuels, not to move vehicles to greater efficiency. So, moving from gasoline to diesel will essentially move you from a 95 gram CO2 equivalent fuel to roughly a 94 gram CO2 equivalent fuel. The California Resources Board largely identified this and rejected the approach of having diesel fuel switching in the light duty sector because of the following. One, the objective of the standard is to bring low carbon fuels into the market. And two, it would be an enforcement nightmare essentially. But I think the former reason is of much more weight. Further, if you look at the California low carbon fuel standards lookup tables, they clearly demonstrate that they are looking at substitutes for gasoline and don’t consider diesel, because it would not be in the interest of the State to consider this minor substitution for a multiple of reasons. One, it wouldn’t really be a lower carbon fuel objective to go to this pathway. But, second, it would also further undermine efforts to bring in truly low carbon fuels into the market. So I think as the Department of Environmental Quality moves forward they should strongly consider the pathway that California Resources Board chose. They worked out this issue fairly extensively and I think fuel switching with another essentially high carbon fuel in a light duty market won’t achieve the objectives that the state is trying to achieve. **Response:** applying a diesel EER could bring down the carbon intensity of diesel used in fuel switches to 79.

- **Options presented in the meeting:**
  - **Option 1:** Single baseline, diesel EER applied to light-duty diesel use
  - **Option 2:** Single baseline, no diesel EER applied
  - **Option 3:** Two baseline standards

  - The intent of the legislation is to reduce our carbon emissions, not to encourage innovation. I think best way is Option 1.
  - Option 3 gives the best results in reducing carbon emission. If we think about the overall impact or method we have to reduce carbon emissions, we know on the transportation side there is increasing fuel economy, which is already being taken care of, in things like reducing vehicle miles traveled. And then there is actually addressing the fuels piece. I think Option 3 gives us the clearest cut way to actually get both fuel pathways, and is the easiest to administer.
  - We did say that we are going to remain fuel neutral, but now we are saying except in this case. I agree probably in the long run, but I still think Option 1 is the best way if we are going to remain fuel neutral and let the marketplace do what it wants to do to reduce carbon.
  - We seem to be trying to base a decision on a lot of assumptions and not enough facts. I think that DEQ can do more research to figure out how to administratively administer the different options. I also think that last time we had this discussion, Andy said that we would take this discussion up again when we had the compliance scenario information together so that we can actually see the kind of the impact it had. It could change all of our opinions once we have that information available. More information that would allow us to make a much better decision.
  - The overall goal is to reduce carbon and Option 1 does that the best way and is the easiest and quickest. If we encourage fuel switching to help us to meet our goal, then innovation can come later.
  - One baseline would make the most sense because of carbon intensity we want to drive towards that. But administering a program and making sure we achieve the ultimate goal, there is a lot of value in achieving success and making sure it is done in the most efficient way possible. Two baselines is a lot easier. That the difference between having one baseline and two baselines isn’t big enough to warrant trying to go through all the hurdles we would have to do to go towards one baseline. If we really want to get this program going and be effective and enforceable we would just go with two baselines. The need to do more research and data is a question mostly of administrative ease and the experience of doing
regulatory programs. DEQ has a lot of experience in that. I respect their position of going towards two baselines to make sure that we can get the program off the ground.

- Anything that we do on this program is going to be extremely complicated and extremely costly. Not only for the agency but for the parties who are trying to comply. But I think that Option 1, DEQ is not going to be the responsible party to have to track this stuff. If a person who it has a requirement under regulation to reduce low carbon intensity fuel on a baseline fuel, they are going to be the ones that are going to be doing the tracking. And if they want to use this as a pathway to get credits then they are going to do the tracking.

- Option 3 encourages innovation.

- Let’s assume for the moment that there is no low carbon fuel standard and over the next ten years there is normal growth in gasoline vehicles and diesel vehicles, and figure out maybe there is more diesel vehicles. I don’t know that most people would view normal growth as a greenhouse gas reduction strategy. I think that what the low carbon fuel standard is trying to do is reduce greenhouse gases below where we would be under normal circumstances. So what we are trying to find is what part of that change over time is attributable to people who are really switching from gas to diesel and we can’t just see how to nail that down with any reasonable accuracy. As a practical matter we need to know what part of that change is actually attributable to people making the switch. And when we put our draft rule for the public and stake holders and the legislature, I don’t think it is going to be enough to just say the regulated parties will figure it out. I think we really have to have an idea of how it is going to work. We don’t know the cause of increased or decreased diesel use.

- Diesel light-duties have been stable for a long time and any change from now on is going to be a change in consumer habits. What is normal increase? We could pretty much say that it is flat or 1% or 2% and anything above that give the diesel guys credit for it. Maybe the petroleum industry could come up with some language on how that would be tracked or how that would happen.

- Awarding these credits is a serious monetary event. So you are opening up the state and other parties to a legal challenge, which I think is a tremendous complexity burden. To the extent possible, we do not want to be taking big estimates and guesses about how much of this is happening.

- My suggestion is that you just set up an application to the state that shows the vehicle switching from gasoline to diesel and that would be the person who would get the credit. So only that portion that really felt motivated to make the switch and demonstration of registration going from gasoline to diesel would get the credits and that would be the extent of the switching. The owner of the automobile wouldn’t be the regulated party, but could trade credits on the market, or handle it through the state.

- It still doesn’t answer the question of whether it was a natural switch or an LCFS switch. And if gas prices are going to increase, there would have been some natural switching over to diesel, because diesel is more fuel efficient and, therefore, you have to buy less gas. It just is really cumbersome.

- I just want to come back to language of the statute. “We want to reduce the average amount of greenhouse gas emissions per unit fuel energy of the fuels (and that’s transportation fuels) by 10% below the 2010 levels.” Again I think the point is that the low carbon fuel standard did not say anything about vehicle miles traveled or fuel efficiency or things of that nature, but that is does have to do with the amount of greenhouse gas emissions per unit.

- Philosophically, I’m hoping that we are all trying to get to a level playing field that doesn’t try to do anything other than focus on the carbon impacts of the various transportation fuels.

- That’s the question on the table, are we reducing carbon and are we innovating new fuels?

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• There are legitimate, practical questions in terms of how to make this work. And it sounds like there are some hurdles. I haven’t heard a fix or insurmountable problems. For me at least, it is still an old question. As Frank, for example, suggests somebody with an incentive to get the credits or whatever can figure out a way to make it work, to come to DEQ and say we’ve got this switching, there is this much less carbon than a business as usual case would have been and this is why we are entitled to whatever. It would be helpful, probably, putting this issue out there and saying DEQ is thinking of going into Option 3 certainly I would give incentives for those who feel they need to comply to really think hard about if we do want to do this switching, if we want it to be valuable to us how would we do it, what kind of case do we make, and are we justified.

• I think with this program, by the very nature, tracking is an essential part of how they work. And there is complexity. But legitimate greenhouse gas savings from clean diesel technology shouldn’t be in this forum. So I think Option 1, while having complexities, because this program will have complexities in a number of areas.

• Our clients are the ones who supply the fuel. We are the ones who get it out to the gas stations, get it out to the farms, or wherever it is going. We track what we sell. So tracking is not it an impossible task. If you move it to any other level it becomes almost impossible, basically we are the ones who can do it. We are not supposed to be picking the fuels. And that is really what Option 3 is going to, we are going to pick the fuels. We are going to eliminate these and force you to go to other things. Now if that is something that people want, and I’m sure there are folks around the room who do, then that is fine. That is a legislative concept that can be brought up next time around, but if it is simply driving towards lower carbon emissions, then Option 1 works and we can implement it.

• Could advisory committee members or somebody from the regulated side provide to DEQ a hypothetical scenario that says in 2020 we think we could, just on the 2010 baseline say we sold X gallons of gasoline, we sold X gallons of diesel for light duty use. In 2020, we have a scenario where we sell Y gallons of gasoline and Y gallons of diesel for light duty use. And we would like to take advantage of an EER on the light duty diesel side and here is our compliance scenario. Could you provide that hypothetical to show that it is a doable, practical pathway?

• The legislation mandated lower the carbon content of the per unit of the fuel. So we are looking at on a per unit basis, we are not looking at an aggregate carbon emission from the state. And if we take that one point, it drives us, in my view, towards Option 3, because that is the option that actually delivers the fuel industries’ ability to execute on lowering the carbon content per unit. And with that I would like to throw in, for other reasons that have been expressed by others, we strongly support DEQ moving with Option 3. Thank you.

• If there were no low carbon fuel standard and just the normal growth in diesel vehicles occurred and there was an increase in diesel vehicles, there might be fewer future emissions than there would have been if everybody was driving 100% gasoline car. But it wouldn’t reduce the carbon content of diesel fuel, which I think is really more of the central point of this program.

• Subparagraph G of House Bill 2186, specifically calls out the fuel efficiency of the drive train. You have more than one consideration in this bill. Option 3 ignores this subparagraph.
  o Subparagraph G calls out the drive train to take it into account for electric vehicles. It is not to account for the switching from gasoline to diesel, and not to encourage that. Being involved in the bill, the intent of that section was not to encourage the switching of one type of vehicle from another. The intent was to account for electric vehicle drive transmission.
  o That is not what the language says.
But it really is about the carbon intensity of fuels and the best way to overall reduce the carbon intensity of the fuels. The entire pool. You take the whole thing and reduce it by 10%. It doesn’t say gasoline, diesel, electricity, ethanol, or any of the above. It says take the entire pool and reduce it by 10%. So you have to take into account all of the constituents and you have to build one baseline, which is one number and it is going to reduce by 10%.

- Does an electric vehicle displace a diesel or a gasoline vehicle? Implementing a two-baseline scenario is not possible. **Response: It depends on the vehicle. Light-duty substitutes for gasoline.**
- Right now we can tell you how much we are delivering to gas stations for the light-and medium-duty markets. You have to get away from what normal switching is. The whole goal is to get better fuel out there. The fuel is here. We know the numbers.
- So again, can you present the compliance scenario with a pathway to DEQ that says here is what we can do, here are the numbers that we have for 2010? Here are the numbers that we think we can have for 2020, and if supplier “A” doesn’t do it, but supplier “B” does it and maybe has extra credits and sells to “A” or whatever. But, it would be verifiable, implementable.
- If a fuel supplier blends that ethanol, they have a RIN number, and at the end of the year, EPA says show us your accounting. And they have to give them pages and pages and pages of RIN numbers to show how much ethanol they have blended from gasoline to make their standard. It is the same thing that they would have to do with diesels or gasoline or everything.
- What about when someone decreases their diesel sales?
- There is normal versus LCFS driven and I don’t think that there should be a dividing line in there.
- Option 1 is the fairest. It can be implemented. There is a cost associated with each Option.
- And I think what DEQ is saying is the cost is greater with Option 1, so they are biased against it. They can’t see how it would work.
- With regard to whatever the statutes specifically states or is interpreted to state, it has already been interpreted once today that we can push the deadline back to 2022 or 2024. There is clearly latitude then to consider one or two baselines. It is interesting that the more regulatory burdensome option is being favored by the regulated party, which is unusual in environmental policy. I hope this trend continues.
- **Summary of our conversation or discussion today.** There are a number of folks on the committee who believe that Option 3 is the best. There are a number who also think Option 1 is better. And we have heard different views about accountability. First of all, let me just ask, is this something that you need to nail down now? Or can we revisit this? **Response: The problem is in the economic analysis. We are going to have to run some scenarios and we are limited in the amount of scenarios that we can develop in the economic analysis.** The hurdle to one pool is the practicality of it and DEQ needs an alternative.
- Can fuel providers come back to DEQ and say this is how we think we can do it?
- We can talk about whether there are still some options. Look at both as we go forward and come back and see if we really do have to settle on one to be able to move forward. But we have to at least take a step forward with this for the compliance scenario.
- Looking at light duty stations, if we have diesel on some of these stations already, I don’t see any reason why we shouldn’t go with Option 3. That seems to make the most sense to me.

**July 7, 2010 Advisory Committee Meeting**
Discussion on including a “one pool” scenario in the compliance scenarios.

- Commenter thought DEQ was still looking for input on how you would actually implement a single silo approach.
- Commenter heard that it should be one and I definitely heard that it should be 2, and there was a robust discussion about that.
- The approach of taking two silos is likely to increase the costs of compliance for within each of those silos. So it is almost a conservative approach to analyze it within two silos, because you can’t have a tradeoff between the two different fuels.
  - I disagree. There is lot of things that are going to have to be tracked under a program like this.
- We are talking about scenarios and I think we need to have a scenario that shows one silo approach.
- Just so I understand what it might look like before we make any decisions. It would give some carbon intensity reduction by switching the light duty fleet from gas to diesel, I mean some portion of it. Is that where the benefit would come? So there has to be some assumption about how much of a switch would occur and what’s the relative carbon intensity between those two.
- Washington is doing a single pool, and you are able to do an analysis of it. Response (TIAx): Yes, we did two one pool analyses. We did an 8% reduction one and a 10% reduction.
- So I don’t see why we don’t do the analysis and if compliance issue knows things we can also do it separately. I don’t think we should borrow this, at least the questions that we have at this point, including in the analysis.
- Is the problem when you go to actually implement this, you don’t know how much fuel switching is occurring. On the ground, how do you actually figure out the new amount of diesel that is substituting for gasoline.
- It is very possible to do that with more precision than what we are talking about. We know that diesel that is pumped into a car is charged tax. We know how much diesel is taxed and we know that diesel pumped into a heavy truck is not taxed.
- For medium duties you have to do an estimate.
- That’s a small percentage, but it’s the whole problem with the medium duties. It’s a small percentage of the number of the vehicles. And we don’t have good statistics anywhere, that I’m aware of, on the ones between what we consider light vehicles and heavy vehicles. And, in Oregon, it is between 10,000 and 26,000 pounds.
- So the presumption in that is that all future light duty diesel sales substitute for gasoline.
- No, above the business as usual.
- So does business in usual in Washington then project light duty diesel as increasing at some natural rate. Response (TIAx): We did not adjust the light duty diesel populations at all. It stays the same. It’s just that it gets a credit in the one pool, and if it’s separated it doesn’t.
- But there is no some sort of middle assumption that there would have been some Normal diesel sales that would happen absent a low carbon fuel standard anyways.
- And just the other projections that we are doing, we are going to project what the base case is and what would happen in 2022. Yes, there would be additional diesel sales that would happen.
- And I certainly don’t expect you to take my word for it, but what I’m suggesting is that DEQ go talk to the people who run those programs to see what kind of data that they can produce. I mean I’ve been working with it for 30 years, so I have some idea of what it is, but you know there are the folks at the
fuels tax branch and you would probably need somebody from DMV and, again, I would encourage you to touch base with (inaudible). He’s sort of the guru of making estimates from all of this.

- So if I’m hearing it right, there could be in the base case a projection of diesel sales that would happen absent of low carbon fuel standard? Then there would be additional diesel sales and scenarios and the difference gets a low carbon credit, but then when you actually go out in the field and try to document how much volume of diesel fuel belongs in the low carbon fuel piece, not in the base case, how do you distinguish?
- Same way that you just did it, is you take here’s the diesel that is doing into light vehicles, project that to 2022, here’s the diesel that is actually sold in 2015 and if there is a difference then that diesel gets credited.
- A projection is fine for modeling, but it would be difficult to use for compliance, which needs to be based on actual data.
- If a guy is driving a gasoline vehicle and the next car that he buys is a CNG or diesel, which would be either way, then how would you differentiate that?
- Sounds like Washington’s scenario assumes that all future light duty diesel sales substitute for gasoline. They didn’t try to parse it between these would have been some increase in diesel fuel.
- There are two issues. One is how you measure compliance and the other is what are you modeling, two pools or one pool. So we kind of mixed those two things up here in this discussion. We don’t have resolution on how you comply.
- Well what I was hoping was that we could still allow running the scenario or running numbers that would allow you to say you get some credit for the switch, without having to decide is it actually implementable.
- I’m wondering has Washington numbers been run already, or is this a draft of them. Is there a huge difference between one silo and two silos? Response (TIAx): In the one pool approach, the diesel dominated. I can’t remember the percentage of the reduction, because the focus of that compliance scenario was to use in-state production and there is a lot of projected canola biodiesel. Because they have a lot of biodiesel production capacity in Washington and a lot of potential canola production. Their one pool scenario was more or less a biodiesel heavy scenario.
- So what this tells me is that even if there were not a big difference in cost that the likely difference in cost is that a one silo approach is less expensive if administrative details can be dealt with, in terms of a market transaction to the regulated parties the one silo approach may be cheaper, at least based off of how the Washington state set up their system. So if we are looking at very conservative analysis of what the impact of this program might be on regulated parties then a two silo approach may be the more conservative for us to take. So I don’t see anything wrong with just, if you want a conservative analysis of what the impact might be the regulated parties to get forward with what we’ve had to give them.
- Each of these scenarios are going to feed into REMI, is that right? Response: Right
- Why are we afraid of getting the information on one vs. two baselines? We haven’t chosen it, but at least we could make an informed decision.
- Chair: Certainly we are hearing some strong requests from some members to run a scenario with one pool. We hear a strong objection from other members that say, no, more conservative approach is appropriate. DEQ is saying they are concerned about implementation so they don’t want to run scenarios that aren’t likely to be possible. I think they don’t have a strong opinion one way or another. I would like us to clear out the information and move this onto a decision-making body, because ultimately, as this committee, we aren’t going to craft the rule. We are going to make recommendations about the rule, but
we aren’t going to decide about the rule. I liken us to be a clearinghouse for information and for opinion and then move it forward. So that tends not get us to closure, but I don’t think we can get to closure on this one any ways. Do you at DEQ have a strong objection to running another scenario? Are you concerned about costs and resources and time?

- There are some real barriers to light-duty diesel that you are not taking into account. We have less light duty diesel models available than we do flex fuel vehicles. It’s going to take a long time to get those out. Also, you have the same problems with diesel that you do with E85, because there are not enough diesel pumps available. They are going to have to start adding pumps. I think it is a more complex issue than you are probably really thinking about at Administratively approving adding a carbon intensity this point.
- You are probably aware that legislature in February suspended the biodiesel mandate for next winter because of the problems we had last year. Once we get to renewable diesel, we won’t have those problems.

6. Low Carbon Fuel Standards Compliance Schedule

January 27, 2010 Advisory Committee Meeting

- It looks like we’re considering a similar trajectory to California. Is Oregon starting at the same place with regard to market penetration of alternative fuels as California? **Response:** The fuels assessment will help the committee consider what is reasonable and feasible with regard to expectations about low carbon fuel volumes. All of the program elements interact with each other: exemptions and deferrals, compliance schedule. A deferral would push the compliance schedule back if our projections turn out to be unreasonable, for instance.

April 15, 2010 Advisory Committee Meeting

- I would be interested in hearing from the fuel suppliers about the decision to move the date to 2022. That means that there has to be a larger reduction in gross terms, because you have growth for two more years if you are going to reduce it to 2010 levels. Therefore, it will have an impact on the programs. It should be a whole committee discussion *(Issue was discussed on June 23, 2010)*

June 23, 2010 Advisory Committee

- It makes sense to use the same horizon year as Washington (2023), because 90% of our petroleum fuels come from there. **Response:** We do not know if Washington is going to move forward with a LCFS. Assuming they do, we do want to be as coordinated with Washington as possible. But the LCFS program does not involve changes in blending at the refinery or pipeline. Biofuels are blended at the terminal or lower in the distribution chain. Therefore we are not tied to Washington, as we would be on other types of fuel standards.
- Will the baseline year stay at 2010? **Response:** Yes
- Renewable diesel comes from a refinery – so it would be important to be on the same timeframe as Washington. **Response:** It is a good point you are making. But different horizon dates for each state provide a more flexibility for the refiners, so they won’t have to produce enough for both states on the same schedule at the same time. A difference in timelines between WA and OR does not change the type of fuel refineries need to produce. When we go to rulemaking, we can look at what Washington is doing
and consider aligning the actual horizon dates at that point. What we want to do here is look at a ten-year phase-in schedule.

- The basic principle of the program is to reduce greenhouse gas emissions. Transportation is about a third of our global warming pollution, so postponing the horizon year from 2020 to 2022 makes a significant difference. The legislature said 2020, and knew it would take awhile to implement the rule. We need to leave the option open to have a 2020 baseline so we can sync with California. The biggest perceived hurdle is the technical feasibility, and biofuels will be able to come on line fast enough to meet a 2020 horizon year. If the economic and compliance scenario work is completed for 2022, there will be no information to support a 2020 horizon year.

- We should have a compliance scenario with a 2020 horizon. There is enormous public support for reducing pollution and breaking oil dependence. 2020 is a workable horizon year and the benefits of this program need to be brought to the state as quickly as possible.

- Can we decide a ten year period is okay, and then decide which ten year period later? **Response:** Everyone is making good points on this. I don’t think we are going to be doing the economic analysis showing compliance with 10% at different horizon years. Forecasting oil prices, etc. is tied to a specific year. There are already many variables and we need to have the contractor only use one specific horizon year. This program is intended not be an incremental change, but to be really a significant change. In order to get these kinds of significant changes you really need to back in your technology to give the companies time to innovate. The original vision with HB 2186 when moving through legislature is that we have rules adopted by the end of 2010 and that is just not going to happen. It’s going to be more like the end of 2011 or later and so if we compress the compliance schedule it could raise the cost of the program. People will have to develop advanced technologies on a faster schedule and that always ends up raising the price of the program. So if we really want innovation, we just have to be a little bit patient. So like everything else we are deciding in this committee, all these decisions are inter-related. We could have an eight year horizon, backload the schedule more and have everything happen in the last two years and you would get the same affect, but I think that could be also a negative. My recommendation would be that we spread the difference 2024 and 2020 and just go with 2022 for the analysis and then when we actually get to the point of proposing rules we can look and see what makes sense right now given what Washington’s done and given where all the litigation is, etc.

- Our assumption is that we would have at least proposed rules prior to the 2011 legislative session. **Response:** We will have at least a draft rule prior to the 2011 legislative session.

- Regarding 2020 vs. 2022; California is going to drive the technology, not Oregon. Because of that, 2020 is the correct date for Oregon to use because it syncs with CA.

- We need some analysis on 2020, because it will be difficult to consider if there is no analysis done on that timeframe. If there is analysis done on 2020, we can then consider a range of 2020 to 2024.

- How difficult is it for the contractor to say that delaying or expediting the rule by a year or two will cost more or less? Is it like re-running the whole model or something they could do at low cost? **Response (ODOE):** It would be both. It depends on what variables you are choosing. There are main variables and variables that are changing the direction of the impact. So some key variables have to be designed on business as usual and the other alternative cases on the different scenarios. If you are looking at changing the time line of the modeling and year of the horizon year you are looking at potentially having to relearn how the alternate scenarios change under a different horizon year. The base year will not change, but you are looking at potentially new interpretation of scenarios or your understanding of these changing costs across the different sectors or the changing baseline across the different fuel availability, the change of the economy, and these are key effects that you want to measure.

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It seems to me that the biggest factor between 2020 and 2024 isn’t that there are going to be huge spikes projected on any of the markets, because generally when we are projecting what is going to happen it is just a steady trend that we project based on historical data. **Response (ODOE):** Not necessarily. If you look at 1990 projection of natural gas or 2002 or 2020 it is a wide scaling range. I cannot assure that it is 2010. Steady trend is what is done in economic analysis to allocate or to show the best case reasonable, so you know what the main dominant potential set of prices to be or likely impacts to be. We look at main variables to adjust these. AAA does this all the time with fuel prices and we go by that.

If we have five different compliance scenarios and we are projecting how much of the different types of low carbon fuels are going to be available in a given year that is going to determine the cost. And so if we compress the compliance schedule then we have to also forecast what the affect is going to be on the supplier of the low carbon fuels, and, for example, construction costs for ethanol plants to be built on a shorter schedule. A whole new analysis would be necessary. And then we run the model. **Response (ODOE):** Yes. And you haven’t even talked about sensitivity analysis.

Is there a way of just using the sensitivity approach rather than re-running the whole thing for 2020? Could we run it for 2022, and ask the contractor to give us an assessment of how the prices would change for 2020? **Response (ODOE):** Answering this would require some work with the contractor.

This is a really important decision. What you said earlier is that we would do 2022 and then we would decide what the rule date is when we get into the rule making process. It sounds like we really don’t have the opportunity of doing that if we don’t have the luxury and infinite amount of money to pay the contractor to do multiple scenarios. Then we really need to pick a date and that becomes the date. And it also sounds like it would be very helpful to discuss this with the contractor to see what kinds of things they think they might be capable of doing and at what cost.

Resolution and compromise means that nobody is entirely happy and it strikes me that the folks who will ask to stick with 2020 are not going to be entirely happy with 2022 and the folks who would like to see this slowed down with a horizon year of 2023 or 2024, are not going to be entirely happy. 2022 seems like a reasonable compromise that works, given the DEQ limited budget and having to pick a date. I would hope that we would hear more from the contractor, such that we could say we can have them go forward with that date, but know that if we moved it up this would be the consequence and if we moved it back this would be the consequence. It sounds to me like DEQ is taking a middle of the road approach that is workable. So let’s give them that chance, certainly until the next meeting, to talk to the contractor.

The converse is that we are stretching out the timeline, and therefore, economic and environmental benefits are diluted.

The larger issue is the greater environmental benefit to the state. **Response:** You are right, where we started was that we want to get the benefit of the program, but we are aiming at a ten year phase in schedule because of the amount of time it is going to take to get the rules adopted. A ten year schedule takes us to 2022. If we compress that then we are probably going to make the program more difficult to implement because the compliance schedule will be compressed. The only reason we are talking about the cost of the economic analysis was just the suggestion that we run the analysis for both years. We probably can’t afford that, but that is not the driver here. The real driver is what is a logical phase in schedule for this program? It is a combination of the horizon year and then that curve between the base year and the horizon year, which we have all talked about as a back loaded curve where most of the reductions happen in the last several years. But we haven’t actually agreed to or nailed down that curve yet. So, as with everything in this committee these are all decisions made that affect each other. But obviously you could have a 2020 compliance year and then change the shape of the curve so it is even more back loaded. I would propose 2022 as a good date, both from the renewable fuel standard and at
the federal government level. It ties all of the actions of Oregon into that program so that as all the fuel companies move forward to change their fuel mix to comply with the 36 billion gallons that all of that would happen in parallel here in Oregon. The other thing that happening is California is discussing the LEV Program, changing all those emissions standards. The year of that full implementation is 2022. So you are going to have all of these new vehicles to comply with this new program happening in 2022. It just seems that you have the stars aligning around 2022.

July 7, 2010 Advisory Committee Meeting

- Regarding the 2022 horizon year: we don’t have consensus with the committee. So 2022 is our analysis year and we are going to do our best to see if we can get any kind of comment about what we would expect to be different if it was 2020. We can’t afford to do the analysis for both years, but I would like to make certain that we keep track of things that would make a difference. We can comment on that it would be substantially similar in 2010 and 2020 would be different. I know that Washington is analyzing 2023. So we will be able to know from their analysis what those kinds of assumptions might make. But to the extent we can bring any information in the final report, even qualitative, I think that committee members would appreciate seeing that affect of that horizon.

- I appreciate the comment and we will work to find a way to provide some sort of background analysis to explore what 2020 might look like. We can go back and compare other state analyses or just a review to show 2020. So I don’t know if it is through this process, but through another process.

- So in our analysis, the percent reduction would be for 2020 at 6½%. To meet a 10% reduction in 2020 I presume would have some effect that we can at least qualitatively describe. Response: After we finish this whole report, sometime next spring or summer we will be doing rule making and if at that point we propose the program that goes with a base year of 2010 to the horizon year of 2020 or a base year of 2013 and going to 2023 we are not precluding that decision by analysis on these years and I think committee members would like to see if there is any information that we could keep track of as we go that would help us know if we did that at that time is that going to make it significantly more expensive to implement the program or less expensive. So we may just be able to qualitatively say talk about how they might be affected by an earlier or later horizon year. If there is some way to qualitatively note that I think that is what the committee members were asking for.

- An earlier completion date for the LCFS program would require a different compliance slope. Response: Our original legislation talked about 2020 and DEQ is thinking 2022 just because of the time it takes to do the rule making and the advisory committee. So it’s still a 10-year phase in and advisory committee members have asked what would it look like for 2020, which would be an 8-year phase in. We would have a different curve. So with that in mind, if you can keep track of any qualitative things you might say about the cost of the infrastructure and so forth, then we could at least get a sense of if we wait or were convinced to adopt it within 2020 horizon year, how that would affect the economic analysis.

Summary of written comments from advisory committee member or alternate December 1, 2010

- The state legislature adopted the LCFS with the intention of reducing the carbon intensity of fuels 10 percent by 2020. This standard would have a significant volumetric decrease in global warming pollution by 2020. DEQ should make every effort not to let the compliance schedule not to slip past 2020. If it is deemed necessary to delay the full 10 percent reduction past 2020, then the projected volumetric
reduction should be made up in the subsequent years. This would assure that the LCFS achieves its desired impact in meeting Oregon’s climate challenge.

7. Updating or Adding to the Carbon Intensity Lookup Table

Summary of written comments from advisory committee member or alternate November 6, 2009

- Oregon should look into encouraging sequestration of carbon through bio-char production.

December 3, 2009 Advisory Committee Meeting

- Carbon intensity analysis should not overlook the possibility of improvements in conventional petroleum fuels.

May 20, 2010 Advisory Committee Meeting

- For landfill gas, are fugitive emissions represented in that carbon intensity? Response: we will research that and get back to you.
- For DEQ, is adding new pathways a workload issue? You want to only go through that exercise for people who are going to be serious about it and produce commercial quantities. Response: Yes.
- For funding purposes, a pilot-scale producer needs to be able to get a carbon intensity number for their commercial-scale facility. Response: DEQ would be able to establish a new carbon intensity number for a small-volume fuel producer, but we would not be required to. If we saw a promising new fuel we could still go below these thresholds and establish a pathway. The fuel volume would be based on the capacity. But the producer would be relying on DEQ having enough time. Is there a way to provide an administrative alternative to acknowledge a producer’s carbon intensity analysis?
- For the new fuel pathway, the fuel producer would do a GREET analysis, and DEQ would be responsible for reviewing that application and validating it.
- Carbon capture and sequestration (CSS) is included in California’s rule to decrease the carbon intensity if a high carbon intensity crude is used. CSS it is being used for oil production enhancement in a number of places and at electric power plants. Commenter is concerned about how CSS would be included in the lifecycle analysis. This will addressed this in the fall in detail. But to the extent that any CCS is directly related to compliance with cap and trade it should not be credited towards the LCFS. The low carbon fuel standard is not a policy tool to encourage carbon sequestration.

October 14, 2010 Advisory Committee Meeting

- When you come to the market with a fuel with different carbon intensity you will have a natural incentive to want to establish a new pathway. If you have a fuel with a higher carbon intensity then you don’t have that incentive and will want to try and hide the fact. That is one reason the significance threshold is geared towards improvement. To the extent we can account for Canadian tar sands or account for countries with high carbon intensity we can use the precautionary principle of this is how much there is and not try to get too much finesse. If we provide as many numbers as possible in the beginning, the market can adjust itself.
- The way proposed all along is that gasoline has a statewide average number as does electricity and diesel. No mechanism exists for individual companies to get their own numbers in the table.

[Type text]
- This is an opportunity if processes change to lower CI. This is a periodic snapshot of what is actually coming into Oregon.
- This does not reflect the refining processes, but crude production.
- If we update the whole lookup table it would take into account the whole process.
- Seems like a three year cycle quite a bit of uncertainty about what the CI will be every three years and it would be better to have an established CI so that if you change your technology and get a better CI then you create a new pathway but have the certainty of an established CI.
- Do we want to update the whole table? Response: Not unless the pathways change.
- For Option 2, are we calculating the mix of petroleum fuels? There is no incentive for an individual company that is reducing CI of its production and refining process because whatever good they accomplished everyone else gets credit for it. Since it is more administratively simple, but only makes sense to do if we don’t expect the CI to get big between the companies. If it gets large, it could be problematic. If the difference is modest, it is probably a simpler way to do it.
- It is mixed together now, the CI for petroleum represents an average. We haven’t gone where individual companies can establish their own boutique CI. If it ever happened that individual producers started deviating we can visit the system; but, having average is easier.
- Is it realistic to expect that petroleum companies will have a mix of high and low carbon crudes, or specialize in low carbon?
- Different companies get their fuel from different places, so they have different values currently. We don’t know what individual CI is so if they changed we wouldn’t know. (it is a basket)
- Unintended consequence of the actions here is that companies might wait to introduce lower CI products.
- A compliance schedule goes for ten years, if at year three we determine the average mix of crude has gone up by two points, we have further to go. The next three years we check it again we are keeping up with it. You could say it would be better to do it more frequently but in the end we still need to get at the 10%. It may be more of an administrative question what the frequency of the reassessment is.
- Main question is should we do it as a pool and keep adjusting the basket or separate it out? Are we trying to create an incentive for oil companies to decrease the CI or create a disincentive to increase it. Or are we trying to get low carbon fuel into the market.
- In favor of keeping it as a basket. Companies are tied into a portfolio of the fields they have which are leased. New fields don’t come on line that often. If we are trying to reduce carbon, shouldn’t we treat petroleum like we are treating electricity which we decided is a basket. If too much of a burden every three years, do it every five years.
- Process of updating the CI is not what is burdensome, it is the rule making process.
- Crude shuffling would occur when the table is changed on a regular basis.
- Oregon is attempting to be a model for other states to adopt similar programs. Some of this on crude shuffling problem will go away when more states adopt. We should not worry about the shuffling in the near term and use the program to leverage long term gains in greenhouse gas reductions.
- Whatever system we set up needs to apply to all because the same variability in feedstock and transportation. When you put in the same basket the bad actors hide behind the good guys. This has an impact on the credibility of the program.
Can Oregon regulate this when there are not producers in the state? Should this go forward, crude should be treated as crude and not penalize the high intensity crude. Calculate on the fuels from the refineries. Option 1A is better.

Oregon is a small player, fuels will be shuffled to our neighbors not necessarily China or around the world.

At a previous meeting, the committee had discussed allowing a new fuel pathway for refinery efficiencies. Options 1A and 2 do not include this. Does WSPA have any comment on that?

Question: Is shuffling calculated in the baseline. **Response:** It is since transportation is a factor.

Option 1A appears to be rather neutral in terms of causing shuffling and will keep things simple in the pool. Option 1B would be the worst in terms of incentivizing shuffling but is the most accurate. Option 2 is a kind of compromise between the two.

Fuel shuffling won’t occur because of Oregon’s rule, we aren’t that significant in the market. California is the most advanced and every time we try to do something different that our neighboring states we make it more difficult on the industry. Doesn’t it make more sense to mirror California and Washington?

In some ways Washington may be looking to us because they aren’t in rulemaking.

We keep talking about crude, but the process of carbon intensity needs to apply to all fuels because you do have a system set up with rewards and penalties.

Petroleum is asking to be treated differently.

Ok with the pool to start with but ultimately but we are looking at how the fuel changes in the future by dis-incent more carbon intense fuels and incent less carbon intensive fuels. Not taking that into account will cause gaming in the petroleum sector. Electricity was a very unique sector because CI changes dramatically from utility district to utility district.

Clarification of 1B, only address a new source or new process for refining the crude. Increases from existing HICF would use the existing table. There can still be sizable increases or decreases from existing sources that will use the old number.

We have established that our market power is very interesting, we aren’t going to cause shuffling. Option 2 makes the most sense by seeing if the industry around us, sending product into our state, has it changed.

Table of all the pieces of the program and when they are updated. Does the schedule include CI updates? **Response:** No, we will add it when we conclude what that timeframe will be.

Treating crude as crude without continual analysis probably is not the right thing to do.

Ideally, like to see all liquid fuel sold in Oregon have a pathway. A basket is less complicated. If we do have neighbors around us like CA that are getting a lower CI value because of the process there, shouldn’t there be a mechanism that allows for buying from those producers?

If there is a pathway established in CA, we should use that number as a default, is that what you are suggesting?

We aren’t creating any numbers for petroleum, just biofuels.

Using 2009 data from Canada DEQ estimated what is coming to Oregon through WA and UT.

Needs to be some ability to piggy back on our neighbors as they learn. Pick one of these options but have the ability to adjust down the road.

Does it make sense every three or five years to update the basket to keep it accurate. We are trying to get from 94 to 86, we aren’t going to get as far as we want, so we should check.
Mark Reeve, Chair, summarized the discussion on high carbon intensity crudes at the end.

- No perfect way to do it
- Trying to get overall carbon intensity down over a ten year period
- Dealing with the fact that our state is a market taker not maker
- In an ideal world without a lot of complications and differences in the petroleum world we should not have a basket. Don’t think we are close enough to that ideal world. We need a simple approach which is starting with the basket.
- Option 1B isn’t particularly attractive particularly with what CA is doing, but if sub-pathways are developed we need flexibility to change the basket as well as bring folks on along side.
- Certainly some version of one is preferred by others.
- Periodic review, over three years is favorable.
- We need to document diversity of viewpoints; there is no right or wrong
- If we update the pool periodically, we are counting for any changes in the crude side of it.
- If making assumptions that carbon will be higher in the future, the interim updates will show that. The end number does not change.
- If we update the average every three years, the actual shift to a high carbon fuel could have happened in year one, there could have been a compliance obligation based on the baseline. More frequently the table is updated the better.
- Don’t see us going retroactively back

Summary of written comments from advisory committee member or alternate December 1, 2010

- High-intensity carbon fuel, such as Alberta tar sands, need to be carefully tracked and reassessed. Otherwise, there is a strong potential that the LCFS will lose ground in meeting its goal to reduce the carbon-intensity of fuels 10% by 2020.
- Energy Economy Ratios (Drive Train Efficiencies) for NGVs. Clean Energy made DEQ aware of the CARB decision to apply a 0.9 energy economy ratio to heavy-duty NGV fleets largely due to legacy vehicles in operation throughout the state. Oregon, unlike California, does not have a significant legacy fleet of NGVs to the same extent in operation, and therefore would ask that DEQ consider a 1:1 EER for HPDI systems and a 0.94 EER for spark-ignited systems. Based on data provided by Westport Innovations (engine manufacturer of the ISL-X) and Cummins-Westport (engine manufacturer of the spark-ignited ISL-G) that will be provided in the appendices, we believe the proposed EER for each system would be reasonable.

8. Credits and Deficits

December 3, 2009 Advisory Committee Meeting
• Oregon may generate business opportunities by incorporating the ability to connect to voluntary credit markets. Trading credits should reduce costs of the programs, since it will give regulated parties options for how to comply.

• Is there potential for secondary markets (i.e., investment firms) to evolve to pool individual charging station owners to sell credits?

• Market for credits under LCFS will not be a “free market,” though, since it will be required by a government regulation, so assumptions about transactions only happening because they are economically beneficial to both parties would not apply.

• Does it make more sense to calculate credits at the point of sale for an electric car, because there would be only a few car dealers that would be regulated, rather than at the point of car ownership? Response (PacifiCorps representative): LCFS credits should be allocated according to fuel use. As electric vehicle use grows, there will be incentives for utilities to install separate meters and charge lower rates for charging during off-peak hours in order to lessen the impacts of load growth. Response (CARB): The LCFS should reward entities that pay for fueling infrastructure by allowing them to claim credits.

• If Oregon does not have a system outside the LCFS for selling credits generated within the LCFS (as California has under AB 32), then there is not as strong a reason for keeping the credit revenue with the electricity providers. Response (PacifiCorps representative): If LCFS credits become substantial sources of revenue for the utilities, it will become an issue for the Public Utilities Commission.

January 27, 2010 Advisory Committee Meeting

• Megajoules as a measurement unit reflects the generation of heat, which is different than energy applied to the wheels which is horsepower, signifying how many times the wheels turn.

• Could unlimited banking of credits dilute the effect of the program in later years? Conversely, getting more GHG reductions early on is helpful for fighting climate change.

• It could become a political factor if a big credit surplus builds up.

• Under the Renewable Portfolio Standard, credit banking encouraged early wind investments and allowed investors to be nimble and manage risks.

• Is there any problem with a business-to-business agreement promising to sell future credits? Response: No, but credits for fuel not yet produced could not be used for compliance purposes.

• If the concern is high credit prices, then capping the price could be a better option because it will be difficult to define “third party.”

• It may not be legal to exclude third party participants, but a good alternative may be to not allow unlimited banking by parties without compliance obligations.

• There is also a risk that a regulated party could sit on a pile of credits (hoarding).

• Would 2015 sunset mean that credits would expire? Response: Yes.

• It would be useful to reframe the question: Is there any value to third party participation, and if so how should they be constrained?

• Potential regulated parties are very nervous about speculation.

• The rules could require registration of third parties.

• SO2 market-based program lets parties buy credits after close of compliance period and before the compliance filing is due in order to “true up,” giving an extra couple of months to ensure they are not out of compliance. Response (CARB): This approach could add complexity to the LCFS credit accounting
• Suggest that the rules don’t contain an absolute prohibition on credits from other programs, maybe say “not allowed at this time”
• Broadening sources of allowable credits could allow the program to achieve the maximum CO2 reduction possible.
• Clarification (DEQ): Oregon can’t control the terms of a Congressionally-passed program, but does have the choice about whether to allow offsets to be used within the LCFS program.
• Could credits be traded with California and Washington’s LCFS programs?
• Perhaps Oregon land use programs with impact on transportation emissions could generate LCFS credits in the future.
• Oversight would be needed for multi-state trades to prevent double-counting
• We should use whatever information we can from the RINs in order to make our administration simpler. Response (CARB): California requires RINs to be reported, and plans to use it to double-check the information submitted for compliance.
• Oregon could end up building a lot of complications and limits into the LCFS, making it difficult for regulated parties to comply and encouraging fuel shuffling between states.
• Railroads fear price increases if their fuel distributors can’t sell blends to them, but have to make up for it by buying additional credits. Response: This is one reason why the choice of who has the compliance obligation matters; in this case, higher up the distribution chain is better.
• There is some concern about large amounts of banked credits building up in early years
• There are concerns about protecting investments made in low credit fuel production capacity

Summary of written comments from advisory committee member or alternate December 1, 2010
• LCFS credits can be banked indefinitely without expiration. Clean Energy supports DEQ's determination that credits can be banked indefinitely without expiration as this provides a regulated party with the opportunity to save credits for future compliance purposes or the potential of selling a credit at a reasonable return when the market is not overly saturated.
• Low Carbon Fuel Credits that are banked should not be compromised. Clean Energy disagrees with DEQ's current position that credits generated and banked under the LCFS program would be subject to an adjustment of carbon intensity at a future date by DEQ when all credits generated under the program and sold during the same period of time would not be subject an adjustment by the DEQ. Clean Energy believes that the DEQ must maintain fairness across the board and DEQ's current policy would harm those who bank their credits.
• Further, Clean Energy believes that DEQ's position will also create an early liquidation of credits in the market as some assumed low carbon fuels face a potentially significant adjustment in carbon intensity when indirect land use change (ILUc) factors are applied. In fact, a potential unintended consequence of DEQ's current approach may be that fuels vulnerable to indirect land use change (ILUc) may oversell their product into the market, falsely inflating the market's performance of low carbon fuel penetration only to discover that the real benefits are substantially less, and those low carbon fuels that provided a true carbon benefit to the program are harmed as the value of credits will have been diluted. A fairer approach by DEQ would be to apply the ILUc numbers that CARB has adopted and adjust credit values on a prospective basis once there is a broader agreement on ILUc values in the regulatory community.
Finally, Clean Energy is very concerned that DEQ's position to postpone the adoption of ILUc factors at the program's implementation and decision to make an adjustment to carbon intensity once ILUc issues are resolved will create a disruption to the market at or near the time DEQ will be seeking re-authorization of the LCFS by the Oregon State Legislature. This

Clean Energy will most certainly provide those regulated parties who are the focus of the regulation fresh allies to oppose re-authorization as many who invest in providing low carbon fuels may find that their fuels do not provide the anticipated carbon benefits. Clean Energy strongly urges DEQ to consider the longer term consequences of its actions, especially actions that could create crisis right before the state considers the longevity and viability of the program. In fact, the uncertainty caused by this potential change could derail the entire program.

9: Buying and Selling Credits

October 7, 2010 Advisory Committee Meeting

Any info we collect is public information unless the entity providing the information can prove that it meets the requirements of Oregon’s a trade secret law.

Could you give us an example of what information would be used to verify a credit? Response: Buyer and seller would both need to report the credit transaction, and respectively, who they sold or bought it from. There are several pieces to a “valid” credit. First, DEQ needs to approve a carbon intensity number for the fuel. Next, a regulated or opt-in party needs to demonstrate (one-time) the way that fuel gets from that producer to them. Lastly, invoices for fuel sale would show the volume of fuel that had been supplied to a retail facility or end-user.

You cite administrative burden as a consideration, what types of information (analysis, audit, etc.) would create such a burden? Response: To show a credit has been generated, a regulated party could show us how much fuels sold and carbon intensity, and DEQ would verify invoices. Response: There are two parts to this- at the sale level, there is the need to verify the number of credits bought match the number of credits sold, verifying the transaction. Then there is a second kind of verification that needs to happen, where DEQ would verify the number of credits generated based on the fuel type, pathways, etc.

To the extent a credit becomes a sort of currency, then the currency has to be trusted, and there has to be a process to verify the value of a credit being sold. Response: So the question there is does the credit need to be verify before the credit is sold, or can it be verified at the end of the compliance year?

There’s a bit of a trade-off here, where the less verification you do, the more transparency is needed in the market to self-regulate itself. The first approach concerns me because it doesn’t provide the market players enough assurance that the credit is worth what the buyers and sellers think the value is. I would favor an approach that increases transparency that keeps the regulatory burden low.

A utility can get Renewable Energy Credits now, would those be essentially the same thing as LCFS credits? Could they apply for these instead of the RECs, or do both at the same time? Response: These are different because some renewable won't have a very low carbon intensity electricity footprint. So they would qualify for a REC but not for an LCFS credit? Response: Remember that the LCFS program
is going to use the statewide average for electricity, so it will be different from the REC. The same thing would go for RINs – someone could sell the same RINS with the same fuel as LCFS credits, because they are different programs with different intents. So they could be sold to different programs, theoretically? **Response:** No, because the credits in each respective program represent very different things. Remember that the 10% reduction from baseline, we’re talking about all reduction, no matter where it comes from.

- So if credits are not fungible, could you choose to sell them as a RIN or a REC or a LCFS credit? And if you can do that and the programs are significantly different on the market, that could create a shortage or a surplus, depending on how that worked? **Response:** A utility that’s buying or selling RECs that is separate from electricity sold for transportation and any associated LCFS credits. Credits would not be fungible, and could not be double counted.

- So if credits are not fungible across programs, you have to take into consideration the market for those as well as for these to see how the market is going to respond and whether there is an adequate supply.

- Our example is slightly different in that we will be producing RINS, and at the same time producing credits under the LCFS program. The credits are not fungible, but the same gallon of fuel will be generating credits under two different programs, but the credit value under the LCFS is not competing with the RIN value.

- In your case I agree, but in Todd’s case, it does have an effect.

- It depends. I’d rather sell credits in the transportation sector rather than in the electricity generation market due to the economics. The economics favor the transportation market.

- This is projected to only be about 5% by 2022 and it’s not a large part of the mix in trying to meet the standards as currently calculated, and then this problem is a smaller percentage of that 5%. So what it’s worth, the program won’t be jeopardized by RINS and RECS. **Response:** I’d like to go back to the discussion about option 1. If a biofuel manufacturer were to sell a LCFS credit twice to two different buyers, under the minimal DEQ involvement option, presumably the buyer would be able to review the records of the seller to assure that the pathway and carbon intensity had been approved for the fuel, and DEQ would expect that level of diligence on behalf of a buyer to validate the carbon intensity, but they wouldn’t have any way of being able to determine whether the seller sold credits to other buyers, and at the end of the year during the compliance reporting period, DEQ discovers that a company sold more credits than they actually generated during that year through production. So the selling company would be in violation, but what about the receiving company that purchased the credits in good faith thinking they’d bought a valid credit, but in fact that credit had already been sold to someone else? What would happen to them under the minimum involvement case? Would they theoretically have to make up the value of that credit later but wouldn’t necessarily have to pay a penalty for being in violation? Could such a scenario be addressed under option 1, minimal DEQ involvement? **Response:** We could require them to buy more credits within the next three years to achieve the desired greenhouse gas reductions. Or we could hold the buyer harmless and require the seller to make up the invalid credits they had sold.

- Even under option 1, there could still be a market where credits are bought and sold that is facilitated by DEQ, where regulated parties notify DEQ of what they’ve sold and that information is posted, without DEQ verification of each transaction, allowing for some transparency in the market with minimal DEQ involvement.

- The last thing we’d want to do is set up some sort of secondary insurance market where companies need to insure against the market not working the way it is supposed to.

- Do you think that this is something that DEQ could fairly easily have a third party contractor provide the verification services and act as a pass through in terms of the cost? Do you see that as a potential
scenario? **Response:** Yes. DEQ has programs like that where there is a pay for service. It is difficult to staff for something like that because you don’t know how many requests you are going to get, and hiring a contractor to manage it is one way of addressing the issue.

- Would it be possible the collective regulated parties could contract with a firm and they would facilitate the process? **Response:** I suppose anything is possible. It seems like the main questions is around having a way to track that the seller has actually generated the credits claimed and that they haven’t already sold those credits to someone else, and a ways of collecting, cumulatively calculating and conveying that information in real time to buyers and sellers of LCFS credits.

- The timing of the credit accounting is still an issue, and at minimum, and annual trueup of the books will be needed. **Response:** Another question which needs to be answered is who would ultimately be responsible for making up for lost greenhouse gas reductions for any credits that were double counted, or sold more than once.

- I think option 2 is a false option, because I think all my customers are going to want any credits they buy to be verified in advanced, and that could put DEQ in a situation where they are unable to manage the load of verification. I would prefer to see the program budget reflect the knowledge that there is a real demand for verification of credits.

- As a potential regulated party under the Oregon LCFS program, we wouldn’t buy any credits unless they were verified, preferably with DEQ, with no clauses that would allow for an adjustment of credit value as a result of discovered errors in reporting. (Public Comment)

- In terms of the verification of credits, due to the uncertainty in the volumes of low carbon fuels that will be produced, and the costs involved with staffing new programs at the state level, the approach of running the program with some sort of third party assistance in facilitating the credit market with DEQ oversight as appropriate seems like a good start.

- I wonder if there should be some consideration existing credit markets that are run profitably by third parties, and a similar market could be created for LCFS credits that would operate under the guidance of DEQ so credits are verified without requiring DEQ staff time and resources.

- Options 1 and 2 don’t seem very viable to me. It also seems like this is going to have to be self-supporting system because the legislature probably won’t provide funding for such a program, so whether it’s a third party or contractor, they are going to have to get the money from an administrative fee on the credits themselves. I don’t think it can be on a % basis b/c if these things are going to go up and down, DEQs costs are going to be fixed each year, so they are going to have to recoup the exact costs of the program each year, so that is administrative aspect that needs to be looked at. I do not think that non-verifiable credits are a viable option.

- Do we need to verify that a particular fuel is that fuel, or can we have an approach that doesn’t verify prior verification for every sale?

- I sense there are three different types of verification that are getting mottled. 1- that there is a compliance obligation to be met and the compliance calculation was don’t correctly, 1- that the transaction is being made on good credit (number of credits sold actually at stated value exist) , and 3- the verification of the credits themselves. It’s unclear to me if there is another way to get a credit other than through DEQ, in which case, why would I want to verify the validity of a credit if I can’t get it on the black market? I’m struggling with the third aspect of verification, and if someone can correct me if worrying about whether a credit can be generated by any other means than through DEQ is a valid concern. I’m more concerned about the first two aspects I’ve described. Is that an accurate portrayal of the considerations to be made with regard to verification of credits? **Response:** The first two, definitely. With regard to the third aspect you’ve described, credits would be generated when a regulated party sold a low carbon fuel. Credits
wouldn’t come from DEQ, and it would be possible for credits to be sold without DEQ being informed, so the question is – do sellers of credits need to go through DEQ to check invoices and verify the amount of fuel claimed as sold was accurate.

- Having a web interface that is run by DEQ as a forum where buyers and sellers can transact could minimize costs to DEQ. Requiring sellers to register with DEQ before selling credits into the LCFS market would provide transparency, but the aspect of verification may still need to be addressed.
- Can low carbon fuel providers outside of Oregon be a regulated party under the Oregon LCFS? **Response:** Whoever imports the fuel into Oregon would be the regulated party under the LCFS.
- This discussion is about how much certainty is needed about the volumes and carbon intensities of regulated fuels being bought and sold to determine whether the standard is being met.
- Blended biofuels sold to retail sellers contain fuels with two different pathways, and would have to verify the carbon intensities of both fuels. And when fuels are blended twice, where is what would be the equivalent to the incidence of taxation, and how will the values of the credits be verified? **Response:** The buyer takes possession of a fuel and blends it, they will know the carbon intensity and volumes of fuels being blended to be able to calculate the carbon intensity of the final product and compare that to the standard. That is the relatively straight forward scenario. Another scenario that poses more of a challenge is where credits are purchased instead of actual product. Regulated parties will submit annual compliance reports to DEQ that can be used to verify that the regulated party does not sell more credits than they have.
- The buyers of credits are going to want to know that the credits are good at the time of purchase, so an end of year audit won’t work as a means of credit verification.
- Who is considered the regulated party? **Response:** If it’s manufactured in Oregon, the producer would be the regulated party, if it is imported, the regulated party would be the entity that imported the fuel.
- If it is discovered that credits which were sold were not of sufficient value at the time of purchase for which they were represented to be worth, who is ultimately responsible for the compliance obligation?
- As a potential credit producer, it is my expectation that quarterly, we will verify that we aren’t double counting production volumes.
- Credits could be sold separately from the fuel which generates the credits.
- We would not sell forecasted credits- we would only sell credits which have been verified. **Response:** In a situation where a seller overvalues credits and sold them, the deficit is sitting with the buyer, but they would not be obligated to make up for that deficit if it could be demonstrated that the buyer practiced due diligence to verify the validity of the value of credits purchased. At that point, the obligation to make up for the deficit would rest with the seller.
- Typically there are contractual remedies built into agreements that would address liability issues being discussed. **Response:** Reviews of credits sold could happen quarterly to help catch them sooner.
- We are in favor of transparency, and think it would help the market run better. We would like to see how many credits are on the market, the number of needed credits, and prevents periodic confusion as in other programs. **Response:** It would also help DEQ because it gives us a sense of capacity and program tracking.
- The challenge if regulating is that the mix in a tank is always changing due to the blending of fuels. **Response:** That would be the case if you had to verify each credit transaction. But if the total volumes of fuels sold are aggregated on a yearly basis, that information can be accurately tracked.
But the issue is the need for accuracy for buyers of credits to know if they are getting full value of the credits they buy. **Response:** I think if we set the rules up in the way we are discussing, buyers could rely on a registered option regulated party information, and if a seller oversold they are responsible for any deficits generated as a result.

If a purchaser of credits wants to know the value of the credits, they will need the volume and carbon intensity data of the fuels purchased in order to know what the credits are worth. **Response:** Each credit will be one metric ton, so there is no difference between credits across fuel types. A regulated party will report to DEQ how many credits they generated based on the volumes and carbon intensities of the fuel the bought or sold. If a regulated party thinks they generated 100 credits but actually only generated 99 because their blend changed, it doesn’t matter because at the end of the year DEQ will subtract the 100 credits and if they don’t have enough credits left, they are going to have to make up the difference. All of the credits they sold would still be valued at the value for which they were sold. By registering with DEQ as a regulated or opt-in party, that regulated party takes on the obligation of selling an accurate credit.

All regulated parties will have to report regularly, and that should verify credit transactions. **Response:** How much due diligence does the buyer need to do before buying credits? Might want to have information posted so potential buyers could know what the production capacity and pathways are to help them calculate and verify the value of credits being sold.

How elaborate does the audit need to be?

We sell a variety of blends wholesale and retail, and the IRS and the State of Oregon show up randomly to audit us, and my expectations here is similar in that at any point, I could be asked to prove the information submitted about volumes and carbon intensities of fuels being sold or generating credits for sale.

There are three steps in the process that have to occur – a credit has to be generated, verified and sold. Before a credit can be sold, it has to be verified, and verification cannot happen before the claim of generation. (Public Comment) **Response:** A program could be set up that way, but it would be very labor intensive to verify every credit before it is sold. We are trying to come up with a system where that is not necessary.

You might look at the program the green power program used by utilities to meet the Renewable Power Standard requirement. That program was all done on a voluntary basis, the generation was contracted out and PGE did the verification itself. That model could be useful for finding a suitable approach here. PGE was subject to audit and there was federal guidance on improper marketing. (Public Comment)

Having false credits on the market would negatively impact the credit market, and so verification of credits prior to sale and transparency to do so are very important.

Fuels can be tracked really well, so there isn’t too much concern over where a batch of fuel came from or what the carbon intensity of blend is.

If sellers of credits were required to post transaction information quarterly, this information could be used to get a closer to real time sense of the number of credits available on the market at any given time. I am a little concern about putting 100% liability on the seller and no liability on the buyer. **Response:** That is why there would be some sort of minimum requirement of a buyer to exercise due diligence in trying to make sure that the credits they buy are bought from a registered opt-in or regulated party.

The federal EPA RIN system has worked because of the robustness of the verification aspect of the program. (Public Comment)
- Administrative request to consider, in addition to the narrative describing this process, can we also have a flow chart with inputs and outputs and time phases for the process, when a credit is generated, etc. diagramming how the process would work. Response: We can provide a flowchart in the final report.

- With regard to the options for levels of transparency, Level 3 - Quarterly reports used for compliance purposes (meet or within a percentage of standard) - this option causes some concern. Meeting the LCFS on a quarterly basis may prove challenging for some fuel types due to seasonal fluctuations in fuel quality. Response: The benefit of a quarterly reporting schedule is that it would create demand for credits. The challenge it may present is that it creates more opportunities for violations and more administrative burden to review quarterly reports. [No voiced support for this option/level.]

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- We need to make sure that the carbon benefit is counted only in one regulatory platform/market. I'm guessing that the LCFS will be more lucrative, until the Brazillion ethanol importers start generating huge sums of credits - which will drive down the price. This presents another problem of devaluing the locally produced low CI fuel.

10. Fuel Supply Deferrals

August 5, 2010 Advisory Committee Meeting

- Compliance adjustment options is to give DEQ flexibility in being able to address a variety of fuel supply shortage scenarios and to be able to implement the appropriate type of deferral, based on a specific situation. If a disruption were so major, the compliance curve would need to be recalculated and the horizon year may need to be moved out.

- How does the issuing of deferrals affect the market place and the signals of creating low carbon fuels? The more forgiving you are, you are diminishing the market incentives, the less forgiving you are creating a premium which is going to create market incentives for more market supply. Response: We are aware that this is an issue and we will try to balance these factors in moving forward with a proposal.

- Are you suggesting normalizing or using a metric? Response: Since it’s a monitoring threshold, you’d want it to be simple and able to be spot it easily because all it does is trigger an investigation, and we want to avoid triggering an investigation every time a small disruption occurs.

- With regard to monitoring, the only entity capable of knowing what’s going on is DEQ, aside from an alert from a producer. With reporting mechanisms that will be in place, DEQ will have an ongoing data collection system, so (determining) when there is a red flag is a management decision, not an advisory committee decision. Response: Agree.

- If a regulated party opts not to comply, what is the enforcement and is the enforcement less onerous than complying? Response: Different violations comes with different penalties, but a key element of penalties is that they would cover any kind of economic benefit gained in addition to the penalty.

- A 25% is huge if you’re talking about total CI weighted fuel. Even 5% is huge because you have to add in the amount you have to do better the next year.

- What would be a reasonable number? Response (Committee member): I don’t know, this is a first flush. Short- and long-term deferrals are based on volume, whereas forecasted deferrals are based on the carbon intensity.
Determining the significance threshold for when a supply disruption should trigger a deferral depends on how far out we’re looking. The purpose of the program is to get more low carbon fuel on the market. So if we were to base our decisions on the amount of low carbon fuel that is currently available on the market, we won’t be able to meet the standard. But we are assuming that there will be growth, and this rule will generate additional demand, so when looking out 10 years, we need to use a more appropriate threshold. The threshold for determining if a deferral is warranted really depends on how far into the future the program compliance schedule is being assessed in tandem with the magnitude and duration of a low carbon fuel supply disruption.

With regard to wanting to build a (low carbon fuel) market, one way to address forecasted deficits is to penalize the low carbon fuel providers for not meeting the standard, because that incentivizes them to get those plants up and running in a timely fashion.

The timing question never was addressed: what is the timing of this process? If a supply disruption happens, it happens quickly. This is in direct conflict with the CCSN component- so it isn’t making a lot of sense right now.

But (the disruption) is only going to be at that plant for those particular regulated parties that have a contract with that plant, so its’ not going to fit into the question of the scenario that has been presented so far today, or that is written up in this document. Response: It’s a good point that can be argued either way with regard to whether a disruption affects every supplier or just those under long-term contract.

Because enforcement costs more than compliance, they (regulated parties) aren’t going to wait for DEQ to conduct an analysis- they are going to have to be out there complying.

In the normal language for fuel supply contracts, to cover a situation where that supplier went down, what would the fuel purchaser do as a “plan B”? Response: All companies have a robust planning department, and want to comply with every regulation in place, and that’s why an expensive, complicated program like this doesn’t make sense. Each company will have its own supply agreements, but it’s not going to be on a universal, industry basis.

The difference is what’s in the control of the company. For a permitted facility, their control device is under their control. Under the LCFS program, a regulated party doesn’t have control of a fuel producer elsewhere.

Will DEQ issue a violation for being out of compliance before the department knows if the scenario comes true or not. Response: For a short-term disruption, when a plant goes down say for example, for two months, the goal would be to have the deferral in place before the compliance reporting which happens as soon as possible in the following year (perhaps sooner). If it’s a longer term deferral and we’re projecting out into the future, and wouldn’t be able to achieve the curve in the year after, that’s less of a problem. So if a disruption happens within a short time frame, DEQ would investigate the nature of a disruption and potentially grant a deferral.

It is important to leave room for what happens in the best case scenario – a breakthrough in technology – we should build flexibility in to the system so if there is a deferral granted for a one-year disruption, and the new technology emerges, it could make up for the difference and the deferral may be revoked.

Does it (the granting of a deferral) have to be a public process? Can it be an administrative process? Response: It depends on how the rule is written. The Department needs to seek advice from DOJ on this topic.

Please consider meeting with a small group that represents the interests involved that can explain in greater detail to DEQ what is going on, because this is all going to be market disruption in a variety of ways, and to understand what is going on, DEQ needs to hear from those that are in that market.
I hope that the fuel cost is connected to this. **Response: That will be addressed via the Consumer Cost Safety Net.**

The system being proposed won’t work in practice because (a disruption) is going to happen too quickly for the first component and the price impacts and the alternative backfilling is going to potentially affect price out there. So to wait until you see something happening and then try to analyze it and implement something a few months down the road isn’t going to happen. For the forecasted deferral scenario, you’re still going to have questions on compliance and meeting obligations under the rule.

Equal to conversation about making sure prices stay low, is making sure the signals are right for the alternative fuels producers. Some of the deferrals (short-term) may just be on a portion of the market, and the entire market wouldn’t go away, so forgiveness would only be on the portion that was affected, and not on the fuels that were not affected, correct? **Response: Right.**

A ten percent reduction in ten years is a significant change and equates to a lot of low carbon fuel, and where we run the economic analysis, we’ll see that we are going to be asking the industry to really reach to get a 10% reduction, and we think its achievable but not easy, and we need to have a process in place to track our progress, and that’s what this discussion is about.

If we step back a little bit and realize that today there is a 90% monopoly on fuel imported into this state, and the price of that (imported fuel) is affected by world events, from spills, from wars- things that we live with all the time. We’ve seen the price volatility occurring and what we’re looking at in the infancy of, is activating a local supply that is additive to what we’re dealing with on a monopoly basis…feedstocks that are not impacted by world affairs and sensitivities. Granted it is still early and hard to see what will be out there in the future, but because local or regional volumes of transportation fuels are less dependent upon the monopoly-imported fuels, you are creating a dynamic, long-term solution, in which volatility should be dramatically reduced. **Response: That was one of the conclusions that California came to, (which is) that diversity of supply is part of the reason they projected that the LCFS program would reduce fuel costs over time.**

I would like to see us stick to the end point. I would use rulemaking to change the end point if it needs be to (so as not to discourage low carbon fuel production), but would prefer not to alter the end point for short-term deficits.

The forecast scenario deferrals seem like something worth exploring because that gives you a sense of where you are on the (compliance) curve, and how you are tracking along that curve.

The short-term deferral scenarios are unclear because DEQ will not be as fast as the market, and the market will get around DEQ. It’s more of a forgive and understand that over a year or two, you want to shoot towards a recovery, but it’s really the forecast approaches that I’m interested in looking at keeping an eye on preserving or re-calibrating that curve.

The overall purpose of the LCFS is reducing carbon emissions because they matter climatically and to Oregonian’s well being. We need to track the cumulative emissions and if there are deferrals and forgiveness of deferrals, we need to take that into consideration because greenhouse gases have a long residence time in the atmosphere, and any lost time makes any future reductions that much harder and more important. There needs to be flexibility in the system to make sure that compliance is achievable throughout the program and there is success, but we need to think carefully about how we shift the curve.

To me, success of the program means getting to the year 2022 and being able to achieve reductions on a consistent basis from there on forward, being able to carry the program into the future and maybe think about phase two of this program. We don’t want to do anything in the short term that would jeopardize
that. From my perspective, the most important thing is not to make up reductions lost in any given year, but getting back on the compliance curve the following year and move fuel technologies forward.

- The idea of banking credits is interesting so that some of the early actors can get the market moving, because in the early years it will be easier to meet the standard and if there are reductions happening that may build in a bit of a buffer moving forward.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- The significance threshold of forecasted supply for program deferral is far too low at 0.1 percent. The forecasts are usually predicted within a 5 percent confidence interval, so the threshold should be outside that range. In addition, if there is a deferral, the lost reductions of global warming pollution need to be factored into the future schedule of reductions.

- Clean Energy opposes DEQ's decision to allow the consideration and potential approval of temporary fuel supply deferrals as such provisions only create more uncertainty for low carbon fuel providers who are investing precious capital to produce low carbon fuels. While well intentioned, such policy actions tend to favor the regulated party and add risk to the very parties who are helping the state move the market in the right direction. As you know, the status quo already presents significant obstacles to low carbon fuel penetration as refiners have a virtual monopoly on fuels commonly used in light-, medium- and heavy-duty transportation in the US today. That is why Clean Energy doesn't understand why the DEQ would want to add further uncertainty into the marketplace.

11. **Consumer Cost Safety Net**

**December 3, 2009 Advisory Committee Meeting**

- The timeframe for an Environmental Quality Commission finding on whether exemptions and deferrals are necessary is too long. Could the Environmental Quality Commission could set up criteria in administrative rule, and then delegate the finding to staff? **Response:** The commission can delegate some things to the DEQ, but when the statute specifies an Environmental Quality Commission finding (as HB 2186 does on this issue), it is unlikely that finding would be delegated to staff. But we could set up criteria so the process could be streamlined. There are other deferrals and exemptions to deal with adequate fuel supply that would be more immediate. The 12 month average is not just a price spike – it is a problem that has been building for months – it’s a building problem, and would need analysis.

- For a temporary spike in prices, it would be unlikely that getting rid of the LCFS in the short-term would have a substantial effect on price because you would not have changed the fuel stock over.

- Washington gasoline prices tend to be a few cents higher than Oregon’s.

- Has DEQ done econometric analysis to see what inputs have driven up the price of gasoline? Wouldn’t we do that to see what caused the Oregon price increases? **Response:** No – the thought was that we would investigate the causes of an elevated Oregon price of gasoline once the 12 month rolling weighted average price in Oregon is more than five percent (proposed) above the statutory PADD-5(WA, OR, NV, AZ) price.

- Right now Oregon’s 12 month rolling weighted average price of gasoline is at 3.2 percent above the statutory PADD-5 average, so it wouldn’t take much of a bump to put Oregon over the proposed 5 percent threshold. **Response:** If the price went over 5 percent, exemptions and deferrals wouldn’t automatically go into effect – there would need to be an investigation as to why the 12 month rolling...
weighted average in Oregon is 5 percent more than the statutory PADD-5. If it was from other factors, nothing would need to be done, but if it was due to the LCFS, then we would need to implement the exemptions or deferrals.

- Is there any way to back out the effect of Oregon not allowing self service? **Response:** Even with the differences in self-serve between OR and WA, WA’s price is still higher. The 12 month rolling weighted averages included in the discussion paper show the normal variation in the system without a LCFS, and with self-serve in WA but not OR.

- The public needs to be aware of the cost of this policy and the commenter wants to ensure that the public knows the real cost of this policy. The commenter felt that this safety net is a fancy way of masking the real cost of the policy. The commenter suggests that the trigger for an investigation into whether exemptions or deferrals are necessary should be when the 12 month rolling weighted average price of gasoline or diesel in Oregon is ten percent, not five percent higher than the price in the statutory PADD-5. The public would then have to absorb more of the cost of the policy before something was done.

- For diesel, the 12-month rolling weighted averages need to be calculated without state tax because Oregon does not have a tax for on-road diesel, and the other states do. CA also has a sales tax.

- Is the task to model the factors causing an elevated Oregon 12-month rolling weighted average price of gasoline or diesel to understand how to identify when these happen? If you don’t do that, then you won’t know beforehand if it will be causal. The statute seems to ask for an econometric causation. **Response:** The proposed approach is to investigate the cause of a price increase once the 12-month rolling weighted average price of gasoline has gone above five percent.

- Some factors listed in the discussion paper would rule out that the LCFS was involved. They would be one-time occurrences that effect fuel supply or elevated crude prices with a resulting spike, and you could see clearly that they were the cause. Econometric analysis would be needed for more long-term trend analysis and to know which variable was trending upwards the most. Econometric analysis would not be needed in all cases.

- If a spike happens, you don’t have a concept what caused it if you don’t have a pre-determined theory of causation. Bounds on the criteria would be helpful. **Response:** DEQ cannot predict all possible events that could cause a price spike. However, at points in the program where the required reduction has stepped up a notch, it may be more likely that any observed price increase is due to a shortage of low carbon fuels. In situations where the standard has not changed and there are no interruptions to the low carbon fuel supply, whether relative price increases are due to the LCFS may not be obvious and an econometric analysis may be necessary.

- As shown on the graph, there is not a tremendous amount of variation between Oregon prices and the PADD5. This would mean Oregon’s price is different than the 20-30 year history. You don’t need to go through a huge econometric analysis to know that the LCFS is at fault. **Response:** The Oregon price has gone above 5% compared to the other states without an LCFS. If Oregon’s fuel was more expensive, the state would want to do what it could to decrease that difference. But if the price difference wasn’t caused by the rule, we’d want to know what the cause was –if the LCFS was not the cause of the price increase, then deferring/exempting the LCFS could make the price situation worse. We would want to do an investigation to determine if the LCFS was causing a price difference and instigate exemptions and deferrals to address this. Also, there have been several times where Oregon’s 12-month rolling weighted average price went over the same in the statutory PADD-5. Oregon’s 12 month rolling weighted average price of gasoline has been over 5 percent of the statutory PADD-5’s eight months since 1983 (3 percent of the time). For diesel, we only have the actual PADD-5 price information, and diesel has not gone 5 percent over the actual PADD-5 since 1983, although it has been close several times.
• What happens if the Oregon 12-month rolling average stays over 5 percent and it is determined the cause is not the LCFS? What triggers the next investigation? There needs to be some flexibility in the rule to address this. If Oregon’s fuel is considerably more expensive than our neighboring state, the legislature will want to look at that. **Response:** DEQ needs to address this situation in the rule. For example, we could say that if the difference stays above 5 percent and the conditions haven’t changed, we don’t need to do another review.

• Exempting a certain company or companies is fraught with problems, while exempting a certain fuel would be valid.

• There is concern if this is the only mechanism for dealing with price. **Response:** The other deferral provisions address fuel supply, but they only indirectly address price. If you have an emergency supply disruption, that would translate into a price problem.

• New companies producing biofuels could be negatively impacted by exemptions and deferrals. Also, there could be gaming with fuel prices that would cause an increase, resulting in the antithesis of what the rule is trying to accomplish. **Response:** We’d need to be careful with using exemptions and deferrals. The exemptions and deferrals would not eliminate the entire LCFS requirement – you would roll back the standard to the previous year or delay the implementation of the next increase.

• One unintended consequence of the proposed 5 percent non-competitive threshold is that such a low threshold for price variability doesn’t encourage substitution. A higher range of allowed price impact would encourage substitution at a higher rate, potentially resulting in stabilization at a lower price later on. A 10 percent difference might be more appropriate for a trigger than 5 percent.

• We need to consider the consumer. Five percent is 15 cents per gallon, which means that truckers will buy fuel somewhere else other than Oregon, affecting Oregon fuel providers. This policy will affect a lot of different people. It’s critical that we get this right or we will hurt someone. **Response:** The most likely reason that the LCFS could cause the 12-month rolling average price to increase above the statutory PADD-5 price is the standard has stepped to the next reduction level, and there was not adequate low carbon fuel supply for that, or in anticipation of that next step in the LCFS reduction, there was hoarding of low carbon fuels. These are situations DEQ could anticipate before actually seeing a price change. The 12-month rolling average is a safety net element that was put into place as a backstop. There are other provisions that look at supply specifically. If we are three months out from a reduction in the LCFS, and we see the supply isn’t there, the Environmental Quality Commission can implement a deferral. That is a more direct way to deal with supply issues. The 12 month rolling average safety net is for when something has gone wrong with the other deferrals.

• Another variable is that because CA and possibly WA also will have LCFS programs, the preferred market for a low carbon fuel produced in Oregon might be elsewhere. Timing is important – DEQ should consider mirroring WA’s timeline (in HB 2186). If we are the first, then we could have problems.

• There has to be a third party that could deal with this implementation issue of exemptions and deferrals for fuel price. DEQ should find a third party to use, as opposed to creating some sort of system. **Response:** We can certainly consider this, but keep in mind that a 12-month rolling average price is not an emergency scenario – this is the backstop where something went wrong, and we’re seeing it in the price. Our goal is to avoid this ever happening by setting a phase-in schedule which can be met with reasonable compliance scenarios, and having a process by which we’re looking ahead, and we’re sure regulated parties will be contacting us if they won’t be able to meet the low carbon fuel demand in the next step down. Then we can change the compliance date beforehand to avoid price and fuel supply issues.
The advisory committee discussed what to do when there is a gap when Energy Information Administration data. Energy Information Administration price data comes out weekly – but there is a 3-4 month lag in volume data. Volume data is necessary to calculate the 12-month weighted rolling average. It was suggested that the most recent volume month could be used, but because there is seasonal variation in gasoline and diesel use, the previous year’s data might be better. The best option might be to take the most recent 12 months data that you have as a first cut.

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- What about (the price of) electricity, CNG, hydrogen? **Response:** The statute refers specifically to gas and diesel. The theory being that since gas and diesel is where the reduction is needed, and if there are cost increases in other fuels which are generating credits or used to reduce the carbon intensity of fuel, they would show up in the price of gas and diesel. We are tracking gas and diesel because they are the compliance points for the curve, and any increases in the cost of low carbon fuels would show up there.

- If there is a spike in fuel prices in Oregon related to a particular low carbon fuel needed, it’s going to take us over a year to get relief from that. What I hear DEQ saying is that whatever happens and our economic study beats your economic study, then regulated parties would have to wait a year to a year and a half for relief. **Response:** Only for the short-term deferrals.

  - That’s on supply, what if supply is there but price triggers (another monopoly develops). Is there a mechanism that should be put in place to enable a more immediate reaction to fuel price spikes? **Response:** Part of it is the 12-month weighted average, so it’s a balancing act. **Response to Response:** We have price gouging legislation in the state that’s based on an incident, and if something comes up than the Governor can respond immediately. Why don’t you have something like that available for the industry if there is some kind of a spike so we don’t have to wait.

- If it’s a rolling average, we don’t have to wait until the end of the year. **Response:** If we had one really bad month because someone cornered the market on low carbon fuels for that month which caused a price spike, the previous months would dilute that.

- A mechanism is needed to act on a shorter time frame to address price spikes in the marketplace.
- As long as it isn’t triggered by the natural variation in the market.
- It would trigger an investigation, not necessarily a deferral. **Response:** DEQ could have a trigger threshold to determine when an investigation is warranted and whether a deferral would alleviate the disruption problem, but the agency could also trigger an investigation of its own fruition before the threshold was triggered, based on the circumstances.

- Going back to the question on non-blended fuels, in a situation where electricity prices go up differential to other places and credits from that electricity are generated and get passed on to comply, are those going to be ignored? Other fuels besides gas and diesel need to be looked at in this regard. **Response:** Electricity providers are regulated in such a manner that would prevent that scenario from happening.

  - The price of the credits is not regulated. The municipalities, PUDs and CODs aren’t regulated. **Response:** In ODOE’s optimized analysis, even if five percent of the cars by 2020 were electric, it would only be 0.6% of demand for electricity in Oregon.

  - I’m not talking about the price of electricity, I’m talking about the price of the credits. **Response:** That would be the market price of gas or diesel, and if the price of that credit got high enough that credits would be needed, that would be reflected in the price of gasoline, which would be caught by the consumer cost safety net, which is why it all comes through the price of gasoline.
and diesel- if we aren’t seeing that go above the consumer price safety net, then I don’t think we need to worry about the other fuels.

- Are we really after GHG reduction, or are we telling out of state producers what they have to produce in order to be able to sell it in Oregon? By doing this, aren’t we saying to people that if you want to sell fuel in Oregon, you need to comply with Oregon standards and make fuel that complies with what we require in Oregon? **Response:** The idea of having Oregon establish GHG reduction targets (which are aspirational, not regulatory) is to achieve our share of the reductions needed to stabilize the global atmosphere, and would require every other state and every other nation to achieve those levels of reduction also in order to stabilize the atmosphere. The intent is to team up with California, Arizona, Washington and the other WCI states and a number of Canadian provinces, everyone doing their share, ultimately helping the federal government and other countries to decide to do their share as well. This rule by itself isn’t going to fix global climate change, but it is a step in achieving the overall reductions that Oregon needs. In SB1059 the Transportation Commission is charged with establishing a greenhouse gas reduction strategy for transportation, and will be looking at this rule in context of the broader program to reduce GHG emissions in transportation, so it’s a piece in a bigger effort.
  - But still, we are basically telling out of state producers that if they want to sell in Oregon, they have to meet certain standards **Response:** We do that with a lot of things.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- While Clean Energy understands DEQ's intent to show consumer sensitivity and Clean Energy believes giving consumers more transportation fuel options than the status quo adds competition and therefore lowers prices, we feel adding a consumer cost safety net adds another level of uncertainty. Although Clean Energy would like to believe low carbon fuels are as cost competitive as natural gas to petroleum, unfortunately, this is not always the case. In fact, this is why a LCFS policy is needed: to create the right policy incentives needed to develop the marketplace so that one day consumers could benefit from an array of competing clean fuels rather than the status quo which is dominated by gasoline and diesel. We strongly encourage DEQ to reconsider the need for a consumer cost safety net in the future if it opts not to remove it at this time.

**12. Implementation Issues**

**A. Use of Biofuels**

**Summary of written comments from advisory committee member or alternate December 4, 2009 regarding the proposed biofuels use**

- Set up a transition fund (like the diesel retrofits) to help the legacy vehicles change fuel filters and fuel lines to take blended fuel, if blended fuel is actually required. Keeping in mind that regular fuel providers could be blending or buying credits.

**April 15, 2010 Advisory Committee Meeting**

- I would assume that all these biofuels would have specifications that need to be met as opposed to mandates for blending. Again, this is a market performance-based system. If something is not meeting
the specification, someone else is going to jump in with a better fuel that is meeting the specification. We need to make sure the specifications are there that meet off-road or customer requirement conditions.

- What do you do when you are in the middle of a job and the equipment is not working? For the LCFS to work, it has to work in individual pieces of equipment. And in much of Eastern Oregon, the equipment operates differently.

- In Eastern Oregon, I have heard a lot about gelling problems they had with 2% biodiesel that we had last winter. The fuel was separating and the biofuel was going to the bottom of the tank.

- Minnesota is not having the same problems and they have been using biodiesel for about five years. The problems Eastern Oregon is having are rampant to the point that in February the Legislature passed a bill that suspends the 2% mandate next winter so that we can look at this problem and see what it is. So it is very real and I’m not sure the existing literature is going to shed a whole lot of light on this. It is a huge problem.

- Minnesota had the first biodiesel mandate and it gets cold in Minnesota.

- The low carbon fuel standard is different from any type of particular blending mandate. The low carbon fuel standard can be met with no biodiesel whatsoever.

- Oregon Department of Agriculture did a great job of studying that issue. The problems have been blown up compared to what actually happened. We have lots of history in Oregon of much higher blends than 2% operating fine in cold weather snaps. Oregon Department of Agriculture did a really good job of testing fuel and seeing what was actually happening out there. One of the primary principles behind having a low carbon fuel standard and not a renewable fuel standard is that we are not saying that you have to burn 10% biodiesel whether you like it or not. At some point, the committee should be able to get to the point that we do not have to keep saying that repeatedly, and we can move past that. We are trying to create a scenario to achieve our carbon reduction goals while letting the market figure out how to make that happen and it can happen many different ways.

- The people (in Eastern Oregon having gelling problems) that you brought up earlier - were they using any anti-gel agents in their fuels? **Response: (Russell)** They were using additives and they were not blending #1 with #2. We have traditionally dealt with the gelling of diesel, which will gel in cold temperatures. We have gone to above ground storage tanks in Oregon to reduce the ground water contamination and the fuel is more susceptible to temperature variations. Businesses with below ground tanks had no problems. The trucking companies with above ground tanks had huge problems.

- I want to encourage us to move on, off of this topic, because it has perennially come up and we have identified that in Minnesota they do not have this problem. It is clearly just a performance specification and storage standard issue, and I think it distracts us from the discussion of the giant list of fuels assessment we have on the agenda. It continues to come up so I believe it is a legitimate concern, but I do not believe this is the forum for us to be trying to find a solution to the ASTM specifications and additive specifications that are required. I would encourage someone to come forward with the specifications that are effective and working in Minnesota.

- I just want to emphasize that this is important and the full analysis that we need to make not be too narrow. The problem with the increase in biodiesel is an issue because it has to do with another rulemaking. We need to make sure that whatever analysis on this makes sure that we do not have many unintended consequences down the road.

- As we are planning something that is large and complicated and is based on assumptions, which affects how we assess if we will have future problems, there is a potential for real interruption of the ability to conduct business. I am suggesting in your compliance scenario that you have to consider those and allow
for that. Not just specific to biofuel, but to all of them. **Response: (CARB)** the use of biofuels was an important and critical issue in California. For one thing, all biodiesel is not the same. The properties and the quality control for some production facilities is not what it is supposed to be. A current study addresses these issues and determines exactly what specifications we are going to be able to enforce to avoid any problems. This is an issue that we need to pay a lot of attention to, because we do not want to have a problem with vehicles or equipment. Avoiding problems could require additional standards for fuel. We are looking at engines and emissions performance. Different types of biofuels might create some increase in emissions. **Response: (DEQ)** To acknowledge the validity of both sides of this discussion, I think we are saying that this is an important issue. With regard to our standard, there are a couple of ways we are handling the potential biofuels issue. One is the back-loaded phase-in schedule. In 2022, we will need to be at full compliance and might have larger volumes of biofuels. The intervening time is enough time to study the quality control and put better practices into place. The statute requires the fuel specs, but it also requires us to defer the requirements if necessary to prevent disruptions of fuel supplies. HB 2186 puts mechanisms in place so that we can defer to the requirements for an additional year or two. Currently, we are trying to design five compliance scenarios. We have to assume in at least some of those scenarios that the problems are worked out and we can have higher levels of biofuels. We are evaluating a range of possible futures.

- Biodiesel blends are also an issue for warranties on other types of engines.
- **Clarification (DEQ):** Provisions outside of Oregon’s rule will limit blend percentages for biofuels.

### B. Storage and Distribution of Low Carbon Fuels

### C. Recordkeeping and Reporting

#### February 24, 2010 Advisory Committee Meeting

- Oregon will need processes in place to protect confidential business information.
- A more transparent reporting system will lead to a better-functioning, more responsive market.
- Does ODOT’s system have exemptions built-in already for farm vehicles? **Response (ODOT):** Farm vehicles with plates are not exempt, but farm equipment is.
- Trading of credits is a unique aspect of the LCFS and needs to be taken into account carefully.
- Adding LCFS reporting requirements to existing ACDP and Title V permits would not necessarily add any efficiencies, just as easy to report separately. Could be legal ramifications as well.
- Chair Reeve pointed out that HB 2186 directs DEQ to look at possible ways to coordinate reporting obligations with existing programs, but that it may not be practical.
- Keeping reporting simple will encourage opt-in parties to opt-in.
- Several committee members expressed their support for using an adapted version of California’s web-based reporting tool.
- It would be beneficial for potential opt-in parties to be able to enter their information before opting in, in order to see whether and how much they could benefit by generating credits.
- Air quality permits seem an unlikely partner for LCFS reporting, GHG reporting seems more likely.
- Oregon will have to modify CARB’s carbon intensity library if we use different calculation methods, or if we decide to pool gasoline and diesel for compliance.
Could DEQ use the LCFS system as the basis for the GHG reporting system? *Response: Different reporters and emission quantification methods are involved, but there is some overlap. We will continue to consider whether it makes sense.*

**D. Enforcement**

- No comments

**E. Standards, Specification, Testing Requirements to Ensure Quality of Fuels**

- No comments

**13. Review of Rule**

*May 20, 2010 Advisory Committee Meeting*

- Is there a way that we can incorporate into rule a set of criteria by with which we periodically review the rule instead of conducting secondary rule making?
- Is rulemaking necessary for a new fuel or could someone submit a lifecycle analysis new pathway and DEQ could approve it administratively? *Response: It is likely that we could approve a carbon intensity number administratively. That carbon intensity number and that administrative approval could only apply to the person that applied. We would need to do rulemaking for another fuel producer to use that carbon intensity number.*
- Will the carbon intensity for gasoline and diesel change? *Response: If the refining efficiency changed significantly, a petroleum company could use the New Fuel Pathway process to update their carbon intensity.*
- The structure of having the companies come to us with the new carbon intensity will create a race to the lowest carbon intensity without ever reflecting an increase.
- Crude shuffling raises greenhouse gas emissions in some other jurisdiction and that is what DEQ is trying to avoid.
- It would be good to track of advances in fuel life cycle assessment before 2016. Science is advancing. Commenter is concerned with waiting until 2016 when this data may be available sooner.
- Identification of hurdles or barriers to increase the use and supplies of low carbon fuels may require visiting earlier than 2016. If feedstocks are waste-based, there are still some kinks to be ironed out between the Renewable Portfolio Standard (RPS), the Renewable Fuel Standard (RFS), low carbon fuel standards, and beneficial use rules. There is some confusion about when something gets to be called a waste, which gets you a zero carbon value as a feedstock. I think there is some upstream or downstream regulatory intercepts that need to be looked at. These are things that would end up requiring changes outside of the LCFS program, but that DEQ needs be aware of. *Response: This is discussing the review of our LCFS program and program rules. We could be looking at those issues, but this comprehensive review is for the LCFS program. So if your points would lead to possible changes in the program and the program rules then we should include it and then otherwise we should not include it.*

Well, if it inadvertently stymies the LCFS program, it would need to be addressed before 2016.
• The National Science Foundation’s study has been recently commissioned and is due out in 2012, and addresses fuel life cycles, including indirect land use change. This would influence the implementation of the LCFS and should be reviewed at that time.
• The harmonization should be reviewed on an as needed basis because changes could happen regionally or federally.

14. Flexible Implementation Approaches to Minimize Compliance Cost
• No comments

15. Effect of the Sunset

Summary of written comments from advisory committee member or alternate September 30, 2010
• The questions you raise in your memo regarding the potential impact of the 2015 sunset to the LCFS are the right questions. In addition, I would add the potential short term impact on needed capital investments to provide clean fuel supply in later years. For example, ZeaChem is building current capacity for 250,000 gallons per year (not much), but could easily expand production capacity to 50 million gallons (with cellulosic technology, maybe one-third of the total LCFS fuel needs). The sunset could serve as a disincentive for those capital upgrades to be made in the next couple years, which could have long-term implications to the program. Removing the sunset in 2011 or 2012 becomes potentially imperative.

October 7, 2010 Advisory Committee Meeting
• As we look at biofuels and taking additional cropland to grow feedstocks, are you going to get water, and are we going to take food away from people in the process. Farmers in eastern Oregon are concerned about the costs that will be borne to them. We need to be careful that we don’t create one problem while attempting to alleviate another. I don’t want to see family wage jobs reduced or elimination. I hope that there is communication with the legislature and the OUC to avoid creating unintended problems in the future. Response: These issues will be addressed in the economic analysis in the October 14th meeting.
• The state RFS and federal RFS are going to stimulate biofuels production and capacity, and Oregon is a small market, so the effect of the sunset seems small.
• There is a significant benefit for locally based companies in Oregon and the resulting effects benefits on labor, rural counties, and secondary business that benefit from the Oregon based biofuels producers.
• The sunset creates uncertainty in the market and does not incent innovation or investment in infrastructure. Instead of asking what effect of a sunset would be, the better question is; what is the benefit of a sunset?
• Proposal for a strong recommendation that the sunset would not be a positive incentive in the marketplace. It is proven that when looking at large capital investments that a sunset date isn’t the actual sunset date. Most of the equipment, technology engineering and design have lead times of up to 18 months, and a sunset may in effect kill market investment in capital improvements for biofuels as much as 18 months in advance of the sunset. On the white paper, the start of the third paragraph reads
“Presumably”- my advice is that we not presume (delete “presumably”) because the sunset will have a negative impact on long range capital planning for new developers.

- There are different views about the wisdom of this program, but the purpose of discussing it is to incorporate the various views on the effect of the sunset.

- Falling back on RFS and RFS2 is a good way to ensure that a sunset does occur, and RFS and RFS2 are not fuel-neutral policies. Instead of a sunset, a review of the program may be more appropriate in 2015. Investors will take a sunset into consideration when planning projects. I strongly encourage DEQ to make the case to the legislature to review rather than potentially derail the program. If you want to encourage investment, the uncertainty of a sunset needs to be removed.

- What would initiate a program sunset? What would cause it to happen? **Response:** If the sunset is not lifted, the LCFS program will terminate effective January 1, 2015 and all compliance obligations under the LCFS would cease to exist. DEQ is not going to take this to the 2011 legislature, but someone else could.

- The debate over the LFCS was close in the legislature, and there is a risk of going to the legislature and asking them to lift the sunset in the 2011 session before we are able to demonstrate how the program will work.

- I agree, but the more certainty I have as a potential low carbon fuel producer, the better.

- I think any uncertainty will affect biofuels more than electricity used for transportation. **Response:** We want to be able to describe how the program will be affected from now until 2015 when the sunset remains effective. We won’t have this program as a partial driver to reduce greenhouse gas emissions and the impact of having the program end on the goal for a 10% reduction in greenhouse gas without making any recommendations regarding the sunset to the 2011 legislature.

- The biofuels industry had a federal tax credit that was not renewed at the end of last year and that has had the impact of reducing our national capacity to produce our particular type of fuel by 70 to 80% and has resulted in thousands of job losses. That is an example of what can happen when incentives are removed, and the sunset would essentially bring to an end the incentive to reduce greenhouse gas from transportation fuels via the LCFS program.

- The frame of the sunset will ultimately have an effect on the 2022 program goal of greenhouse gas emissions reductions. With regard to the impact of LCFS on agriculture, the feedstocks for fuels typically won’t come from labor intensive lands, so the tradeoff isn’t one of jobs or producers. On electric vehicles infrastructure, LCFS won’t be the driver for infrastructure, but it could affect choices drivers make for the vehicle miles traveled in an electric vehicle.

- I would hope that we would produce wheat that is used for food and the wheat stover that is left over from harvesting the wheat would then be used to produce biofuels.

- To the extent that there are early creation of credits in the first couple of years in the LCFS program and the program sunsets, there wouldn’t be any value to the credits upon sunset of the program – does anyone have any thoughts on that?

- It’s clearly a taking and it clearly devalues the credits from the outset if they have a risk of evaporation sometime in the standard.

- If there is not LCFS, one might expect that it could dampen the ongoing development of electric vehicle infrastructure. DEQ recognizes that there are other efforts currently underway to build electric vehicle infrastructure, and the LCFS is ancillary to those efforts.

- Having this program in place helps as a driver to further electric vehicle development in Oregon.
- One of the big barriers for all low carbon fuels is getting the infrastructure in place, and one of the potential benefits of an LCFS is the incentive that is created for biofuels infrastructure. By creating the demand for credits potentially creates demand for infrastructure development.

- We may not invest in low carbon fuels in Oregon as we would like to without the incentives to make them pencil out.

- Right now there is overlap between the initial couple of years of the program and a decision about the sunset. We are envisioning 2012 as the first reporting year and 2013 the first compliance year, so somewhere in that year a decision about the sunset will need to be made. DEQ is investing resources to this program with the recognition that the sunset could go into effect in order to demonstrate to the legislature how the program will operate beyond the sunset date.

Summary of written comments from advisory committee member or alternate December 1, 2010

- The 2015 sunset should be eliminated. The sunset creates uncertainty for investment and potentially makes the program more costly. The majority of benefits to Oregon accrues in the later years of the program and will be missed if the sunset stays in place. The state’s investment up to this point will be fairly meaningless without removing the sunset.

- DEQ correctly recognizes the negative impacts of the current sunset clause in 2015 to the development of low carbon fuels in Oregon. ZeaChem is currently constructing a 250,000 gallon per year demonstration scale biorefinery in Boardman, which will come online in 2011. Based upon the successful operations of the demonstration facility, ZeaChem will begin to develop commercial scale biorefineries and is considering Boardman as the site of its first commercial biorefinery. Businesses such as ZeaChem need long-term policy in place to support and incentivize new business opportunities, such as low carbon fuel production. Recommendation: Since the LCFS goal is to reduce carbon over a 10-year period by 10%, it does not make regulatory or business sense for the LCFS to sunset in 2015. By extending the sunset to 2022, Oregon will send a strong signal that low carbon fuel production is encouraged in the state. In addition, the timeline will be consistent with the federal Renewable Fuels Standard (RFS2), which sets volume production goals until 2022. ZeaChem supports DEQ's efforts to extend the sunset provision through legislation so that current and future low carbon fuels producers can be certain the state of Oregon is committed to this industry.

VII. Calculating Carbon Intensities for Oregon’s Transportation Fuels

1. Direct

December 3, 2009 Advisory Committee Meeting

- DEQ may not want to include a hard number in the carbon intensity table for electricity, because the number is definitely going to decrease over time due to the Renewable Portfolio Standard. Instead, perhaps the rules could provide a process for the electricity carbon intensity value to be updated annually. DEQ will get information annually on electric utility emissions through the greenhouse gas reporting rule.
• Electricity carbon intensity could also go up – it fluctuates due to weather and other causes, and fuel providers should not be surprised by such factors beyond their control. A rolling three-year or five-year average may work best.

• Post-consumer biomass sources, such as consumer waste and plastic waste, are not on DEQ’s list so far, and since they will not have indirect land use effects associated with them, they will have an advantage. This technology may be coming sooner than we realize. **Response (CARB):** CARB has investigated waste oil as a feedstock so far, and plans to analyze other waste sources, all of which will not have indirect land use effects.

• Is extraction process included in the life cycle analysis? Commenter’s specific concern is ensuring that higher emissions from Alberta oil sands crude are reflected in Oregon’s carbon intensity analysis. Information on carbon intensities of Alberta oil sands was provided by Western States Petroleum Association for committee members. **Response:** Yes, the extraction process is included in the life cycle analysis.

**January 27, 2010 Advisory Committee Meeting**

• How recent is the information on oilsands crude, and can we get more recent data? **Response:** DEQ is using 2009 data for the proportion of crude from Canadian oil sands.

• Electricity source data as presented is misleading. Committee member can provide DEQ with more detailed information on the source mix for individual utilities, so that refinery electricity information will be more accurate. **Response (CARB):** California looked at refineries as a sector, rather than individually, when calculating that portion of petroleum carbon intensities. If they are disaggregated for electricity sources, then they would need to be disaggregated for other aspects as well. California used averages for initial calculations, but may reconsider this decision in the future.

• How are crudes tracked in Washington vs. California? **Response (WSPA):** California’s Energy Commission monitors crudes used in California and has extensive, as well as more up-to-date, data. Washington relies upon the federal Energy Information Administration data, with a delay in availability. WSPA has submitted studies on oilsands’ carbon intensity, which DEQ has posted for committee members.

• Lag in numbers is concerning. What data will determine compliance with the program targets? **Response:** DEQ will need to track the numbers over time to see if the crude mix has changed significantly from what it was when the baseline was set, to ensure that carbon intensity increases in the base fuel don’t outweigh the benefits from alternative fuels under the program. DEQ will be able to track this from compliance reports, which will be more up-to-date than Energy Information Administration reports.

• Why doesn’t DEQ require petroleum companies to report their crude sources and volumes as part of LCFS compliance? **Response (WSPA):** That would present antitrust problems as well as confidentiality issues. Information currently reported is filtered and consolidated to account for these concerns. **Response:** DEQ will track information on oilsands and other factors that are most likely to make a significant impact on carbon intensity over time.

**Summary of written comments from advisory committee member or alternate April 21, 2010 regarding electricity issues.**

• We do not see a simple way to calculate utility-specific values since each utility relies upon some amount of undifferentiated power purchases to supply a portion of its retail product. Also there is a question on
whether a carbon value should be imputed to renewable electricity where the environmental attributes have been sold (and if the answer is “yes”, what should the imputed carbon value be?).

- If the Department chooses to move forward with utility-specific values, PacifiCorp requests the rule also include a petition process, whereby an entity may petition to update a utility-specific value. We are concerned with locking in a utility-specific value based upon a one-time calculation. Doing so could disadvantage entities wishing to install charging equipment within PacifiCorp’s service territory. We also anticipate the carbon intensity of our retail product to decline over time, which would likewise increase the value of transportation electrification (and thus LCFS credits produced) within our service territory over time.

- Finally, until our utility commission provides guidance, it is unlikely PacifiCorp would opt into the LCFS program. There appears to be a possibility for a utility to opt in either: 1) as a direct owner and user of electric vehicle charging equipment (and thus retaining title to the electricity sold for transportation use) or 2) acting as an approved aggregator on behalf of our retail customers (where the appropriate rights have been conveyed to the utility by the retail customer/charger owner). I only bring this up to make sure no one assumes a utility will necessarily opt into the LCFS program. Such a conversation needs to occur at the public utility commission and include stakeholders. Before opting in, PacifiCorp will need a commission decision articulating whether registering LCFS credits is an appropriate new task to be added to the regulated utility’s job description.

May 20, 2010 Advisory Committee Meeting

- Electric utilities are still going to have increased load growth, even after accounting for conservation. Neither conservation nor renewables will completely offset future load growth. Natural gas will be the source of that new electricity. Oregon has emission performance standards, so utilities will not be investing in any long term resources that involve coal. Natural gas is a good balance for renewables because of the ability to come online and offline quickly.

- We could use the IRP (individual resource plans) to calculate carbon intensities. The smaller utilities will be a little bit more difficult.

- A better way to calculate the electricity carbon intensity would be by utility, or ideally by time of day by utility. That would be ideal, but that becomes administratively untenable and complex.

- We need to think about the ramifications of starting to look at different fuels differently. For example, since we put all of gasoline into a bin, we should put all of electricity in a bin.

- I think it is a logical jump to attribute the marginal resource demand to electric vehicles.

- We have an integrated resource blend. If I was building a new factory and I had to do greenhouse gas reporting, do I get to claim only the marginal electricity that I’m buying? Conversely, if I have an old pulp mill or lumber mill that has been around for 100 years can I claim just using hydro? It is not a first in/first out system and so we should do it by utility.

- The frequency of calculation is important, especially in the Northwest with hydro regimes changing year to year. The carbon intensity may increase for a utility from one year to another or decrease.

- Renewable Energy Credits might not be appropriate for the LCFS

- Commenter thinks the carbon intensity of green power could be used if it charges a vehicle.

- If Oregon utilities are held accountable for their production through the LCFS, that creates an incentive.
- Commenter thinks the statewide average is better.
- Some utilities have a lower carbon intensity than the statewide average, and might protest this. **Response:** DEQ met with representatives from OMEU, OPUDA and Rural Electric Co-ops, and interested utilities several times to get a sense of this issue, and the feedback was that the statewide average is acceptable. There are really good arguments to be made on all sides here. There is not a real right or wrong answer, but we are trying to develop a program to reduce the carbon intensity of transportation fuel over the next ten years. Electricity use over the next ten years is going to be primarily for other purposes besides transportation. Transportation will never be more than a quarter of a percent of the electricity used in Oregon over the next ten years. Hopefully, it will grow over time. So whatever we do here to incentivize power plants is not going to be felt in their system. What is really driving them towards lower carbon sources is the renewable portfolio standard. Whether we provide utility-specific or marginal or average is not going to really affect them. They may not even opt in at all. To me, it makes more sense to think about using a statewide average and whether it is the marginal 59 or whether it is the average 52. It is one of the things that we can re-visit in 2016 and we can certainly re-visit it in 2022 when we are thinking about re-upping this program. There are other forces that are much much more significant driving utilities towards renewables and we should just keep our LCFS program as simple as we can. Also, given that people are going to buy an electric car and we don’t know where they are going to charge or sell their car, who knows what kind of incentive we are really sending to consumers. Keeping it simple with one average number makes a lot of sense, however there are other views that are perfectly valid too.
- Commenter agrees with using the marginal increase for electricity in concept. Another issue is the charging during the night versus the day. In terms of connecting the Renewable Portfolio Standard (RPS) and low carbon fuel standard, I think there is a close comparison to the Renewable Fuel Standard (RFS) and the low carbon fuel standard and the two should not be connected because they are achieving different results. Similarly, I think the RPS’s and low carbon fuel standard are separate in the sense that one is trying to drive renewables within the electricity market and one is trying to address carbon intensity in fuels and those are two separate things.
- Okay, so what are the barriers to opt-in or what are the things we can tweak to encourage opt-in to make this an effective part of the rule? Would it affect your decision to opt-in if there was one average number or whether each utility had its own number?
- A utility could voluntarily beef up their portfolio and renewables, decrease their carbon intensity, and market that. If you assign just blanket average carbon intensity then there is no value to sell.
- If the carbon intensity is zero versus 59, they have a more credits to market. **Response:** You are making a valid point. But under the federal regime of cap and trade, they are going to also have to pay for all of the carbon from the electricity that they are selling into this market. I don’t think they are going to be making investments right now just to support electric vehicles.
- If the utility opts-in we they get the credits, but getting those credits has been motivated by somebody else’s choice to purchase an electric vehicle.
- There are new groups that want to just serve electric transportation markets as an electricity retailer. Do they get lumped in with all the existing utilities?
- Statistical research methods are highly accurate and hugely cheaper than metering electricity use of electric vehicles with a sub-meter. So I would encourage us to not do what California did with, unloading ridiculous costs onto the system.
I think there are two different things that we are trying to do. One is how do we get people to opt-in? And then the other is, once they are opted-in how do we encourage them to get cleaner electricity. Once people have opted in then we can create a market between the utilities to create cleaner fuels. So a statewide average is fine for opting in, but once they have opted in, maybe we can revisit this and talk about how we encourage competition between the utilities to clean up the fuels.

Cheap power or lower carbon power is an economic driver and it brings manufacturing to locations as a value. And as carbon is going to get regulated more and more, we are going to see manufacturers heading towards lower carbon power. So I don’t think we want to average that out and take away that affect for this sector.

Part of the reason for doing this is the competition, right? To be able to provide a service that somebody else can’t provide. So I think in this limited case of a new entity coming in to provide electric vehicle that is connected to cleaner energy that makes sense to include them to have a pathway to get credit for it. Under the current electricity law in Oregon, we don’t really have competition between utilities and they are definitely not going to compete for service area around low carbon fuel standards. There is no reason to try to create a competition between them.

An exception in public utility regulatory code allows unregulated sale of electricity to vehicles. One scenario is that we could allow a fuel pathway for anyone that access those particular rules and anybody else is going to get the marginal new resource power and then you have it covered.

DEQ would establish the carbon intensity for electricity at the new resource power level of 59 for all electricity in the state with the exception that if power is sold through this process described above was where there is a special statute or rule that they are accessing, they could apply for a new fuel pathway to go along with that.

It is important for homeowners to have an easy opt-in process to get approval from the utility for credits. If the utility does not opt-in, the homeowner should automatically be allowed to opt-in.

Commenter is unsure about including activities such as truck stop electrification in the LCFS, because HB 2186 had truck idling and low carbon fuel standards in different sections for a reason.

Using the new resource power as the mix ignores the fact that we do have all of this existing resource that we are generating electricity with. Given the time of day, the actual electron that this car is using isn’t necessarily the new resource power.

If we choose the statewide average, we will set a precedent, and will not be able to go back to individual carbon intensities.

The advisory committee group present found the following solution acceptable. DEQ will establish the carbon intensity for electricity at the statewide average for all electricity in the state with the exception that if power is sold through by an electricity supplier by virtue of the PUC rule that allows unregulated sale of electricity to vehicles, they could apply for a new fuel pathway to go along with that. Sub-pathways for specific utilities cannot be used.

DEQ will use the statewide average electricity carbon intensity for electricity used in the production of fuels.

June 23, 2010 Advisory Committee Meeting

Putting vehicle CO2 emission for ethanol at zero is not intellectually honest. Response: There needs to be a footnote explaining that there are emissions at the tailpipe, but they are neutralized by the CO2 consumption by the plants used as a fuel feedstock.
Summary of written comments from advisory committee member or alternate July 27, 2010

- First of all, I think electricity is our only hope of matching the scale of today's need for transportation energy. UCO and Biomass and Waste to fuels will only get us part of the way there. Electricity and efficiency has to get us the rest of the way there. In the next few decades, I can see that the heavy freight world is unlikely to switch to electricity. At the margins like hoteling of trucks, and on-shore power for boats and maybe even switching engines for rail yards, but largely diesel will remain and will need to be done better. While everyone is excited about natural gas, I think the loss of coal will absorb that quickly into the electricity markets and may make it less attractive from a price standpoint. Which leaves us with Personal vehicles - for which I think we have too much of anyway, but also these have a reasonable hope of going electric.

- I also see that collecting the data on electric car charging would be relatively easy to account for for these reasons:
  - Electric car buyers will start in two groups - captive fleets and residential enthusiasts.
  - For a captive fleet I believe that they will notice the load and cost growth on their bills and will be able to plot that new demand. The utility will likely notice that as they will need to be involved in the installation of charging stations. Ditto for the residential user. If 4 or 5 residences in one feeder add home charging stations, likely the distribution infrastructure will need to be adjusted - again, hard to miss for the utility/aggregator.
  - The argument that electric cars will soon be charging in multiple utility jurisdictions and therefore it will be impossible to tell what the individual is generating credit wise falls flat on its face for one reason. Money. How long will utilities, malls and workplaces pick up the personal fuel/electricity costs for free? I say not long. As soon as there is any significant consumption, the meters will show up on the charging stations. They already have for trucks - Shorepower. Free power is an anomaly of today that is there only to get people excited. It won't last.
  - So, the aggregators will either be public metered charging stations, fleet fueling and storage yards or residences - none of which will slip by the notice of the power providers and those that pay for them.
  - Now related to carbon intensities of the electricity providers - a state grid mix won't cut it, because there is an incentive to go lower than that by providing renewable power. If I owned a charging station chain, I would buy RECs or offsets at $1/tonne from landfill gas capture, bundle it with the electricity provided at the charging station and accumulate large amounts of credits to sell in the LCFS at a substantially higher price given the likely scarcity of credits inside of a fuels cap compared to an economy wide cap. This would be a fair way to play int he LCFS as I currently see it. What DEQ may want to consider is limiting the dedicated carbon credits to such a business model to voluntary RECS only. This would ensure that the power was actually linked to a renewable source and reward the further expansion of renewable power to help our country ramp up for the electrification of the transportation sector - which must happen if we assume that transportation activity continues as it is or grows. Offsets would help restore or make other parts of the grid more efficient, which may or may not provide additional capacity to power transportation. But what we really need is more renewable power generation infrastructure.
• Which leads me to the title of this email - we simply must ensure that aggregators/utilities do not use their RPS compliant power required under another regulatory construct to generate credits in the LCFS cap. This is the double counting that I fear. That's why if a utility is to aggregate that load from EV's they should be generating the credits through the purchase of **Voluntary RECS** or any portion of their portfolio that is not meeting their RPS thresholds. It would not be difficult for them to purchase these in blocks and track the accounting.

• This would lead to a CI of...<1? Or zero divided by 3 for the EV efficiency factor? I think that voluntary RECs powering EV’s is closest to the ideal for personal vehicles. These credits should be worth the most.

• We wish to continue working with staff on the actual CI value given to our facility in Boardman because we feel the electricity component is not correct. Ie. Our electricity is 100% hydro, unlike statewide average which includes coal. It is important the companies have an avenue to fully develop alternative pathways and show the true ci values of the process.

2. Indirect Land Use Change and Other Indirect Effects

• Commenter is troubled at idea of including indirect effects for vehicle components. This goes beyond fuels, which is the committee’s charge. **Response:** Example comes from California’s analysis. **CARB ultimately decided to include only indirect land use change effects.**

• Will land use for non-biofuels be considered? **Response:** Yes.

• Indirect impacts analysis should not focus only on alternative fuels, but should also consider indirect impacts of petroleum fuels.

**June 23, 2010 Advisory Committee Meeting**

• Advisory committee members also want to talk about indirect effects other than indirect land use change.

• All fuels have indirect carbon effects.

**Summary of written comments from advisory committee member or alternate June 25, 2010**

• Under an intellectually honest system –if we are going to review indirect land use for biofuels – which in reality is expanding the system boundary of the lifecycle analysis to include economic market mediated impacts…. Then we have to look the lifecycle analysis expanded boundary for all fuels… because all fuels have an economic market mediated impacts. It is my belief that Oregon will be well served to let the science develop on all fuels before including any number for any fuel and certainly it would be unwise and scientifically unjustified to burden one fuel with an indirect impact if we are not burdening other fuels with their specific market mediated impact.

**August 5, 2010 Advisory Committee Meeting**

• **CARB’s ILUC numbers were used in all scenarios, except for the scenario that does not include indirect land use change.**

• The economic analysis will be looking at what would happen if we didn’t use any ILUC number, and what would happen if we used the highest, to bound the possibilities. Preliminary results are scheduled to be presented in October with an opportunity for committee members to give input, and final results will be presented in November.
I would like to put a proposal on the table now. Since equity requires us to look at not only the numbers for biofuels but also look at petroleum and other factors that are not considered in petroleum. And as we know the science is in its infancy, and we are making guesses that do not do justice to our efforts, and keeping in mind that the real work (towards GHG emissions reductions) is back ended, it might be a legitimate approach to give ourselves two years before making a decision to see where the science advances, and use an ILUC number of zero for the time being. **Response:** *This is the approach that Canada took. Washington is taking the average of all available ILUC numbers currently in use.*

- Did someone from California say they did it both ways? **Response:** Yes, California also ran their scenarios without indirect land use change, and the volumes of fuels only changes between either two or four percent. Our scenarios will be different from California’s.

- Intellectually, these other approaches offend me, because we’re talking about trying to attribute conversion of land to soybean crops in Brazil to the LCFS, when it’s just as likely that the conversion is due to the production of McDonald’s hamburgers. We’re trying to measure things we can’t control and that are outside the bounds of our science.

- Clearly there are ILUC impacts, even though we may not agree on what the actual numbers should be. We need to incorporate the best number that we have today, so let’s use the best numbers we have today, and review them in the future.

- We’re using 2010 as the baseline going forward, but yet there has been a lot of investment in and biofuels used in Oregon from 2006 forward with the biofuels mandates, so we’re not recognizing those investments and contributions to the (LCFS GHG emission reduction) target, so it might be more appropriate if we move forward to use a 2006 baseline instead of 2010. What does the statute say with regard to where to start from? **Response:** *I think we have flexibility in the statute. It does state 2010 to 2020, and the net effect of what you are saying is that we would be shooting for less than a ten percent reduction because we would already be counting some historical reduction so we would get less than 10% going forward. We could start with a 2006 baseline and go for a 12% reduction and get to the same effect, or go with an 8% reduction in 2010, just go with what we’ve got.*

- When you go from a (ILUC value of ) hundred to fifteen in a matter of years looking at this complex issue, it highlights how challenging this is from a scientific/modeling point of view, and the sensitivities of the inputs and assumptions that are involved, so there is still a lot of work to be done. What is missing is a measure of the indirect effects of petroleum (production), so what we’ve got right now is an analysis that is being refined for quantifying the indirect effects focusing on biofuels, but there’s not been an analysis on the indirect effects of petroleum, so that’s another reason to wait until that is done more authoritatively.

- If we were to make a commitment to formally evaluate the science around ILUC numbers say in two years, would that work for you? It’s an improvement over trying to make a guess as to what they are today, but I would like to ask the scientists in the room (if there are any) if we can expect something from the National Academy of Science or other entity? **Response (attendee):** *The national Academy is looking at the role of sustainability and environmental issues, so the modeling aspects aren’t necessarily going in the direction you are proposing. But the EPA and CARB are working on this issue.*

- None of the scenarios include indirect land use change for conventional fuels.

- ODA would go on the record as having the position of favoring waiting until the science evolves.

Foreign government laws, policies and incentives have a much bigger sway on what is happening in terms of their crops than do biofuels, that I think to take the best numbers available now would be taking a number that could use further refinement.
• CARB has done the analysis on the indirect land uses for petroleum and petroleum products. The question right now is that some folks have suggested other numbers that CARB does not agree with, and that is what is being debated currently.

• CARB may have done an analysis of indirect land use, but has not analyzed indirect effects, and there is a lot of contention around that.

• There is a lot of criticism of the oversimplification of the information used in the CARB process.

• **Response (DEQ):** I tend to think in terms of the practicality of programs and what the outcomes will be, and under any compliance scenario under the LCFS, biofuels will play a significant role. One of the big factors that we have to address is the current EPA limit of 10% ethanol in gasoline unless you go to an E85 vehicle, and the E85 infrastructure. If we don’t have an indirect land use factor, what will probably end up happening is we will end up with more corn ethanol or cellulosic ethanol if it becomes available than we would have otherwise had. In either case (with more corn or cellulosic) ethanol, we’re probably going to be creating an incentive to create that E85 infrastructure, and that is what is needed in the long run. From a practical standpoint, if we don’t use an ILUC number, we are still going to get a lot of the benefit of building the E85 infrastructure that we will need later on if it turns out that there is an associate land use effect and we start shifting more towards cellulosic ethanol, so there is still an advantage to include ILUC at some point, even thought there is still uncertainty about what ILUC numbers should be used today.

• So if you don’t assign one now but when the science is better to re-evaluate, in 2013, the regulated parties will need some sort of regulatory certainty as to what their compliance obligations are.

• I think that we need to acknowledge that it’s a real phenomenon. It’s one thing to say it’s a zero number, and another thing to say it’s a real phenomenon that we think need to be worked on, and we will include a number a certain future point in time.

• Another option to go forward could be to start with a low number (i.e. the Purdue number) and use it until we have a better number.

• From our perspective, (WSPA) thinks that land use should be included, and that is reflected in the written comments we submitted.

• Waiting until the science around ILUC numbers evolves is a good idea, but I’m hearing a discussion about a singular number, when reality will be a suite of ILUC numbers that will be assigned to each appropriate fuel, so it is important to recognize that value in waiting to assign ILUC numbers to any particular fuel until ILUC values are available to apply to all fuels in question. **Response:** Yes, individual ILUC numbers will be assigned to different feedstocks. It may be that not all will be assigned at the same time.

• Is seems like the scenario that would be the most sensitive to it would be the scenario with and without the ILUC number. **Response:** The one that would be the most sensitive and includes the most conventional biofuels is the compliance scenario that will be modeled with and without ILUC.

**October 7, 2010 Advisory Committee Meeting**

• The National Academy of Science has announced that they are going to do a comprehensive analysis in 2012, but it is unclear what comprehensive means and how it intersects with what the CARB working groups are doing.

• I would be interested in learning what groups are working on the NAS effort that aren’t on the CARB working group.
My understanding is that the NAS study will look at indirect effects, not just land use change.

What is the timeline for the CARB 2012 review- will it be finished by the end of 2012? **Response:** The CARB expert workgroup has to report to the CARB Board in the beginning of 2011, and CARB Board will have to act on it and CARB would then have to incorporate any changes after that as part of their 2012 program review. I do not know when in 2011 CARB would make changes to their ILUC numbers.

In a previous discussion we’d talked about rolling in any indirect effects- is that correct? **Response:** We discussed incorporating any changes to ILUC numbers after a program review.

With continued research, the trending of ILUC numbers seems to be a decrease in ILUC values. The ranges of the numbers out there really illustrate how competitive ethanol is to gasoline in terms of the carbon intensity of the fuels.

One consideration to make is having a process where scientific data, such as ILUC numbers can be updated and corresponding changes to the standard can be made outside of a formal rulemaking process. This would allow for a more timely updates to carbon intensities.

If ILUC is not included in the rule initially, a rulemaking would be necessary to include it in the LCFS program at a later date. Building an administrative process into the rule up front would provide a means for updating and/or adding indirect effects in the future as better information becomes available.

There will be a process for setting carbon intensities for different fuels and fuel pathways, of which the ILUC value is a subset, and every time the ILUC changes, would you need a new rule for a new fuel pathway? **Response:** There will be a lookup table in the rules that will have carbon intensities for associate fuels. According to the advice DEQ has received from DOJ, if we have a pathway that applies to anyone, it has to be in a rule, but we can by order (by Department action) have a unique pathway, so if a new product comes out between rulemakings then we can create a carbon intensity value for that fuel and incorporate that pathway into the rules the next time the rules are update, But if there is a ILUC that needs to be added that would apply to all fuels, that would require the change be made via a formal rulemaking process.

This has such a potentially large impact on the whole program and there is still a lot of work going on, rather than picking a time-certain date to incorporate ILUC values, it seems more reasonable to incorporate the numbers at such a time that we have confidence in them and there is consensus as to what ILUC numbers should be used. **Response:** DEQ isn’t committing to a specific date, just trying to identify a general timeframe when we can revisit the issue and make a decision. DEQ is currently considering including the lookup table without ILUC numbers, with a note that ILUC numbers may be incorporated at some point in the future. We have various reviews built into our program, the first in late 2013 or early 2014 and the big one in 2016, and either one of those would be a good place to review the data and add the ILUC if we were to conclude that the science had evolved to a point where there was sufficient certainty in the ILUC numbers such that they should be included in the LCFS program to calculate carbon intensities of fuels.

Or you could conclude that they shouldn’t be included because of investments already made. **Response:** Potentially, but you would need to review the information first.

We have to realize that while there is still uncertainty about what ILUC values should be used, it is inaccurate to say that not including the ILUC data is a scientific approach. Not including that data is just as much of a decision as choosing one of the current methodologies. We need to send the low carbon fuels market the message that we will be adopting the best available science at a certain time so the market can adjust and prepare for that. I think having a date certain decision point takes the politics out of the debate as to what the best available science is and which data set and/or methodology to use.
**Response:** As a practical matter, we can provide a date certain recommendation to the Commission, but we cannot commit that the commission will take any action in the future. It’s a trade-off between incorporating a big moving target now versus the uncertainty of not having anything for a while, and it is important to look at it at a time certain point to review it. By not picking a set of ILUC numbers now, DEQ is not saying that indirect land use change does not exist, but that there is not enough certainty at this point about what those numbers should be to include them in the rule initially.

- From the perspective of a fuel producer, is it better to err on the side of caution by setting a larger ILUC value now and potentially lower it later if need be?
- I strongly suggest rolling the indirect effects recommendations into the 2013 program review for Commission consideration. That would give regulated parties certainty time to adjust and implement. During the first years of the program, this will affect a relatively small amount of fuels that will be obligated to comply.
- Having the ILUC in the rule from the beginning would favor lower carbon fuels faster. By making the choice not to include ILUC initially, it would delay the buildup of lower carbon fuels because you’re decreasing the differential between conventional biofuels and where we hope to go with lower carbon fuels. That is a real impact, especially when the difference in some of the ILUC numbers out there is taken into consideration. There needs to be a date certain time to incorporate an ILUC. What is really important is that the message sent to the market is this ILUC matters and the values will be adjusted over time. **Response:** It may be helpful to have a column in the table reserved for ILUC with an asterisk indicating that it has not been established but will be included after the program review selected.
- If and when we add an ILUC we would have to then adjust our baseline starting year to recalculate the carbon intensity of blended fuels. Credits that were generated and banked prior to the incorporation of the ILUC could be adjusted after the ILUC is incorporated.
- The Renewable Fuels Standards help us achieve our greenhouse gas reductions goals during the early years of the LCFS program, and we are more concerned about the later years, and this dampens the supply in the later years. Banking credits is potentially a big issue, and compounds the effects. The RIN system has dealt with a similar situation, and the rules in that program state that credits generated in the initial years of that program are only good for a certain amount of time, and credits could be allowed to accumulate after a certain amount of time. **Response:** One possible approach would be to say the credits generated before the year 2013 have a lifespan of 3 years, people would be aware of that fact going into the program. What would be the effect of that type of an approach?
- That is a good idea because it creates certainty.
- The shorter the time period that those credits are good, the less value they will have. **Response:** It would reduce the incentive to generate early credits, but as was stated earlier, RFS is already providing incentives in 2011-15, so it might be a good trade-off.
- That seems like a valid approach.
- That would provide certainty to the process.
- WSPA thinks ILUC should be included in any proposal that goes forward, but does not have a recommendation for which ILUC numbers should be used at this time.
- (Dwight Stevenson from Tesoro – on the phone) Speaking for Tesoro, choosing to ignore any indirect effects, you are effectively saying that the indirect is zero, and there is not effect of taking food out of the food chain for the production of fuel, and that will over stimulate the use of biofuels. You want to pick your best estimate and use that, and adjust as appropriate. The effect of using biofuels or conventional
fuels will be best regulated by using your best estimate of the carbon intensity out there. My recommendation would be to use CARB’s numbers because they are the best vetted ILUC numbers.

- Several members of the advisory committee, DEQ and chairman Reeve thanked Jeff for helping the committee better understand the approaches being used to estimate indirect land use change effects.
- *We talked about how credits might expire, but some credits may not need to.* For example, credits generated by the production of fuels made from waste won’t need to be updated because the feedstock is a waste product. The idea of letting credits expire just came up in the discussion of today’s meeting, so we should think about that more.
- (Tesoro, on the phone): There are three things that happened when you take crops and turn them into fuel 1- food becomes more expensive and people will eat less of it, the amount of fertilizer and water used on crops to increase productivity, and therefore more land will be put into food production, which is the indirect land use effect. What hasn’t been discussed yet in Oregon is the farming intensity. There is some effect from putting more fertilizer on the ground and increasing N20, increased production costs for fertilizer, and increased water use and the effect that has on the displaced uses for the water used to irrigate more crops used for fuel. The CARB analysis showed that about half of the effect was from new land, and the other half was from the price signal that pushed the market. The carbon intensity would tend to increase the carbon intensity of crop based fuels.
- *Do you know if that has been discussed in California or elsewhere?*
- Yes, it is being discussed in California. **Response:** It seems unlikely that we will have all the information we need by 2013 on indirect effect, because ILUC is different for each fuel pathway, but we should have enough information to make a decision about indirect land use changes, but other indirect effects could be taken up during the 2016 legislature or potentially beyond that date.
- Concerns also exist in the marketplace regarding the indirect effects of petroleum production. And those studies are likewise underway. I would like to respectfully disagree that the early CARB GTAP methodology is the best vetted study to help determine the appropriate ILUC values to use.
- As we move forward, at some point there will be an incorporation of ILUC in the economic analysis. If we are going to go forward without an ILUC number the first few years of the program, will it be included in the model used to generate the economic analysis. **Response:** Mike Lawrence of JFA will present the effects of lower carbon fuels and compare the changing attributes of the compliance scenarios to demonstrate how they affect the economics.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- We strongly agree with the recommendation to wait until the science is more firm regarding indirect land use effects before including any value.
- We want to make sure that no iluc is added for biofuels without a corresponding indirect effect analysis and number for all fuels since all fuels have indirect effects. It is important for indirect numbers for all fuels to be added at the same time.
- The LCFS was adopted with the recognition that a lifecycle carbon analysis of fuels needs to be taken into account. This is a primary distinction between the LCFS and renewable fuel standards. This lifecycle analysis assures that undesirable impacts like land conversion and tropical deforestation are limited. Indirect effects should be incorporated at a date certain with the best available science at that time. Environment Oregon previously co-wrote a letter to DEQ regarding this subject. We continue to stand by the comments provided in that letter.
- DEQ's approach to indirect impacts, including indirect land use change (ILUC), associated with low carbon fuel production demonstrates the evolving science and understanding of this complex issue. We
strongly supports DEQ's recommendation that indirect impacts not be included in the LCFS at this time in order to allow for further scientific study. The California Air Resources Board (CARB) recently acknowledged that previous ILUC estimates were incorrect and has proposed to lessen the ILUC impact in the California LCFS. DEQ has proposed a reasonable solution to re-examine the science of indirect impacts in 2014, and, if necessary, in 2016, in order to accurately account for potential indirect impacts.

- Recommendation: it is important to evaluate indirect impacts for all fuels equally including liquid fuels, gaseous fuels, electricity, and all other fuels so as not to disadvantage a group of fuels compared to others. It is not until the science is well understood for all fuels that any indirect impacts should be included in the LCFS.

3. Energy Economy Ratios

December 3, 2009 Advisory Committee Meeting

- Commenter interpreted reference to drive train efficiencies in HB 2186 to mean the committee would be looking at vehicle improvements such as CBT transmissions for heavy duty trucks, rather than the efficiency of all vehicles which use a certain fuel.
- For each fuel, there will be newer efficient vehicles and older, less efficient vehicles on the road. Did California look at just what is on the road now, or did they also project future vehicles? Response (CARB): The fuel economy of alternatives to gasoline was compared to gasoline vehicles, while alternatives to diesel were compared to diesel vehicles, using existing data from existing vehicles.
- California’s analysis did not compare gasoline vehicles to diesel vehicles, so it doesn’t take into account that diesel vehicles are more efficient. Request to pick this issue up in more detail, especially with reference to whether we want to encourage a switch from gasoline to diesel in the passenger vehicle market to get GHG reductions. Response (CARB): California separated gasoline and diesel in order to provide incentives for improvements in both fuels.
- Commenter wants to use California format and update it over time (i.e., gasoline and diesel are always normalized to one, and the EERs for other vehicles are considered relative to gasoline and diesel, and expressed as multiples of gasoline and diesel).
- Will the analysis account for urea injection technology in diesel engines? This technology will be here for heavy diesel next year.

January 23, 2010 Advisory Committee Meeting

- Isn’t considering EERs adding conservation into the LCFS, which goes beyond considering carbon intensity of the fuel? Response: The EERs are intended to put different fuels on an even footing by taking into account the energy that gets to the wheels and moves the vehicle, not simply the amount of fuel energy in the tank. The LCFS rule would not try to change the efficiency of vehicles using any type of fuel, but to account for differences in drive train efficiency.
- What happens if the drive train efficiency of a class of vehicles improves over time – do we need to recalculate the EERs? Another dimension is how often the baseline will be updated, i.e. if drive train efficiency increases for gasoline, the baseline would need to be adjusted in order to preserve the technology-forcing nature of the LCFS with regard to fuels.
- Commenter is afraid the committee is confusing energy content of the fuel with the ultimate use of the fuel.

[Type text]
With regard to the EER for electricity, the 2016 CARB rules are going to apply to cars sold in 2016, which is tiny portion of the existing fleet in 2016. Response: My impression is that there was not an accurate attribution made to exactly what the fleet is going to be. There have been rules that increase the efficiency up to 30%. So new cars as of 2016 will be 30% more efficient on average and by that time, from then on, it is going to be the latter half of our low carbon fuel standard when we will start to accumulate more and more electric vehicles. So that is assuming that that is going to be the dominant effect by 2022.

Roughly speaking the fleet turns over in about ten years and so about 10% per year, so in 2016, if 10% of the cars will be 30% more efficient so it is overall 3% for the fleet and in 2017 it will be 6% of the fleet and so it will phase in and it is not 30% yet. We are ramping up towards that 30%. So they are probably penalizing electric vehicles in this calculation. Is that correct? Response: Yes.

An EER of four is more accurate now, rather than three. We are using a value of three here for the EER, which turns out to be very significant in the carbon intensity calculation. And we know that four is right currently, and we know that three will be right sometime in the future, so why are we using three? Response: It is a much closer match to the future conditions. However it might be possible to use an EER of four in the first year, and then have it decline linearly until 2022.

In support of the EER of three: the standard for the next new vehicle coming out is going to be a three.
  o But that won’t be the fleet until ten years from now and then the three will be correct.

At slide 26 addressing EV EERs, the 122 mi/gal Oregon assumption for PHEV/EV is in the CARB ballpark (119 mi/gal), but additional information on EV fuel economy appears to be coming from USEPA in August when it plans to publish in the Federal Register its proposed Revisions to Motor Vehicle Fuel Economy Label (RIN: 2060-AQ09). I’d like to see that information inform our analysis.

Drop scenario 3 and do not devise any new scenarios that do not include ILUC. Even if there is ultimate disagreement on the ILUC numbers used, I think not including ILUC is not defensible.

Include RFS2 proportionate share in BAU case for both Ethanol and Biodiesel. It seems realistic that Oregon will be in the middle, neither exceeding nor being willing not to meet its proportionate share for RFS2 compliance. Therefore costs associated with developing infrastructure, etc, can legitimately be considered outside of the LCFS.

**VIII. Compliance Scenarios**

2. Fuels Assessment and Biomass Assessment

January 27, 2010 Advisory Committee Meeting

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A lot of biogas CNG is getting “locked up” for electricity generation in order to comply with the state Renewable Portfolio Standard.

April 15, 2010 Advisory Committee Meeting

- Are EPA’s RFS2 biofuel goals based on an assessment of bio-feedstocks such as biomass waste or biofuels crops? **Response: (DEQ) Yes, They have a whole chapter on biofuels feedstocks available nationwide (Chapter 1.2 of EPA’s RFS2 Regulatory Impact Analysis).**
- Lane Counsel of Governments is studying diverting grass straw from other markets. There is a large portion which doesn’t have feed or other value. Annual rye, for example, is not in demand from the Asian market. The material is being restrained from being burned. They are having storage difficulty in most of the Willamette Valley, which is driving the price down. The market is highly volatile, anywhere from $12 to $45 per ton. You may have to do a study that looks at projecting the cost out into uncertain market demand conditions.
- Some portion of material is going to Asia as raw boiler fuel. We probably can do something here with it and compete on price.
- On liquefied natural gas (LNG) use in the compliance scenarios: I think not including LNG is unreasonable given the trajectory of growth and the fact that the technology is heavily commercialized for medium to heavy vehicles in particular. It is probably reasonable to include zero in the low compliance scenario, but given the trajectory of growth in transportation LNG use and the fact that the technology is well commercialized for medium and heavy-duty uses, it is unreasonable to count zero LNG contributing to compliance across all of the scenarios. Therefore, I think we should reconsider that and include a scenario with a high LNG estimate, and potentially a moderate as well.
- This is based on EPA and (California’s) analysis, both of which are in a dynamic process, which means that things are continually changing.
- Some of these fuel volume minimums and maximums would be competing for the same feedstock. **Response: (DEQ) That would be taken into account as the compliance scenarios are developed.**
- The high case for biofuel is understated because it assumes that all 50 states are competing for low carbon fuels. The high case should assume that we would have more biofuels than we produce in Oregon.
- If you look at California’s analysis, we are not going to get to where we need to get on the low carbon fuel penetration with our existing fleets. So it is relying on high infiltration, whether it is E15 or flex fuel vehicles or more compressed natural gas cars. The actual infrastructure is not there. If we really want this thing to work, we are going to have to address the vehicle side of the equation, in terms of supply. I do not know how to do it, but that point should be made.
- I just wanted to frame the agricultural residue collection aggregation a bit. For a small scale commercial plant you are looking at say 20-25 million gallons, and that is what the early ones are being proposed at. You are talking about between 300,000 and 500,000 (gallons). This is by far the largest aggregation of agriculture biomass in the history of the country. So the reason that feedstock cost numbers are not firm is that no one has ever collected material at that level.
- One of the benefits of the flexible fuel vehicle is that you do not have to blend all the way to E85. You can use 50% ethanol. Will there be changes in engine technology which would overcome some of the energy density penalties that you have with ethanol? I mean obviously all the (existing) engines were designed for gasoline and not for a higher-octane fuel. **Response: (Wybourny) The first question, let's say that instead of going all the way to E85, you go to something like E50. It may be the pricing of E50 could be closer to gasoline and it helps you in terms of pricing for a high price ethanol and E85. The**
challenge there is that then you need to have more vehicles using E50 to use up the ethanol. The second question: I am not a vehicle specialist so I cannot answer that.

- Butanol is much more transparent than Ethanol. What is the legal ability to use Butanol as a fuel and what about the intellectual property for producing Butanol? Response: (Wybourny) I know that companies are talking about actually taking existing corn ethanol plants and converting them over to Butanol.

- Can butanol legally be used as a transportation fuel? Response: (Wybourny) Yes. The problem is that butanol you can blend at the refinery, but you have to make sure you keep it segregated from the rest of the gasoline pool, because the rest of the gasoline pool is all blended with ethanol.

- DuPont has a biobutanol project as well. I feel comfortable that the economics are going to work out.

- Could you comment a little more on infrastructure issues and using E50 in the E85 vehicle? Response: (Wybourny) There are issues about trying to even use E85 because you have a fuel that is too low in Reid Vapor Pressure. One way forward is that you have butane at every terminal to blend that in. But then you force all of these terminals to have butane spears, which is a challenge in itself. The ASTM committee is likely to allow for lower blends of ethanol less than E85 so that you can meet the vehicle pressure minimums for the ASTM standard for E85. Now how would you use E85 at the pump? One way is that you could have E85 and then you could have the blending pump. You could blend the E85 with gasoline and have a mixture that is less than E85. I am not a distribution specialist. Our distribution person has looked at this a lot.

- Why aren’t you testing off road equipment for E15? Response: (Cleary) Earlier than the year 2000, we have some concerns with using E15. We believe that the tier two vehicles were designed to be more able to adjust the blending ratio (with air) to accommodate a lower blend mixture than an E15 would present to the engine. With older cars, we would probably have to reserve gasoline pools so that they would be able to use something less than E15. They are flexible enough to handle E10. In most cases, they are not capable of using E15.

- If we do not make this change to E15 until we satisfy all of the non-road small engines, outboard motors, etc. we are letting the tail wag the dog. The huge amount of volume has got to go into transportation vehicles and my personal opinion is that it is time for the small internal combustion engine manufacturers to come into the 21ST century when it comes to being able to use other than true gasoline.

- I would actually agree with you on that statement. However, being on the front line of retailing fuel products, it would be tremendously helpful to have research that we can turn to. Response: (Wybourny) Clearly, there has to be some changes in the design, etc. to small internal combustion engines. They are way behind the curve compared to the vast amount of internal combustion engines used for transportation. If necessary, then one of those pumps will just have to be gasoline with no oxygenates in it and then I guess the marketplace will decide at that point.

- Currently in Oregon, E85 is actually priced on an energy equivalent basis at the pump. And you have a 42 cent a gallon state tax credit. The economics of it, for an individual consumer, is favorable. I would say that one of our barriers is the perception of ethanol and E85 in the marketplace, but also people buy flex-fuel vehicles (FFVs, which can run on gasoline or any blend of gasoline and ethanol up to E85) and have no idea that they have a FFV. We run into that all the time where we are telling people, you know you could be saving 90 cents a gallon right now because you have a FFV and they are completely surprised.

- There needs to be some work done by the EPA to accept butanol. As for somebody patenting the process, I think the answer is yes, they are.
DEQ is considering not including algae fuel in the compliance scenarios, but EPA did have a number for algae in RFS2. How did you come up with that number and would you recommend that Oregon include a proportionate share as we move forward in looking at biodiesel as a future fuel for Oregon? **Response:** (Wybourny) I really do not know what number we came up with for algae. We talked to individual algae companies and got some information from them. NREL did a study for us and they estimated, the energy needs, production volumes of different algae technologies, open pond, etc. and we assessed the life-cycle impact based on that.

If you were giving these talk four years from now how optimistic are you that cellulosic ethanol and diesel would be working? **Response:** (Wybourny) Clearly, there is a tremendous amount of effort working on modifying the pathway and from there to drive that sugar into more hydrocarbon rich molecules. We could try manipulating the fatty acid pathway, again, starting from sugars. The issue is they are heading to Brazil to use sugar from sugar cane. So, I still believe the crux of the matter is, are those organisms productive enough in their synthetic capability, are they going to be able to handle and manage the a lot dirtier intermediate sugar that come from the production of the intermediate for lignocellulose. Therefore, I am confident, as I am a technologist myself, that they are going to be able to engineer these organisms and they are going to be able to meet some economic targets based on sugar. The real question is can use sugar derived from lignocellulose.

There are challenges to each of these technologies and just because you have developed a technology in the lab and demonstrated it in some sort of a simple pilot plant does not mean that it is going to work on full scale. It is a very challenging pathway for any of these technologies. I think it helps that DOE is funding to offset some of the capital costs and some of the development costs as well as the USDA’s funding. We have the renewable fuel standard, which requires that that fuel is available and has to be used. I am very optimistic that we are going to see a lot of cellulosic biofuel being produced, but it is a slow start because there is a lot of development work that has to happen before you commercialize.

We have to disabuse ourselves of these zero emission vehicle annotation for electrics. They are relocated emission vehicles. Nighttime charging is not gas, it is coal.

It is zero emission at the tailpipe, but in the lifecycle analysis it is not zero emission. There is an emission impact in generating additional electricity. **Response:** (DEQ) When we are talking about other pollutants besides greenhouse gases, the location of the emission is critical. We tend to have issues with ozone in our urban areas. Therefore, when we say zero emission vehicles, we are primarily talking about tailpipe in terms of an ozone strategy. In terms of climate change, the lifecycle analysis will capture all of this. It will take into account the emissions from power plants and the efficiency of electric vehicles and see what the benefit is.

When will the economic analysis be able to look at those other benefits of local air shed?

Are you going to address how much capacity is going to be required for these charging stations? I would like to see some information on constraints on where we can generate capacity. **Response:** (DEQ) I do not know if we have that quantified, but hopefully Maury will able to address the capacity of the grid to accommodate electric vehicles. In May, we are going to be taking on these and issues related to the carbon intensity of electricity and who the opt-in parties will be.

Have you done an estimate for the gas taxes that will be avoided by using electric cars? **Response:** (James) Obviously as an ODOT person, we want a gas tax. There has been a pilot study on the per mile charge which will be part of the conversation going forward. Charging stations are equipped with the technology to read miles.

Since electric motors can generate a lot of torque that there is hope and promise for use in heavy duty applications. **Response:** (James) Yes, they are available. You are right about torque.
There is actually an electrical application on air travel in of Los Angeles and Long Beach.

What issues that might arise from commercial establishments providing charging infrastructure for electric vehicles? Will they become utility providers under the regulation? And at what level will they charge an extra implement? **Response: (Galbraith)** In general, there is a prohibition in this state on the resale of retail electricity. In other words, if you purchase power from Portland General Electric, say if you are a MacDonald’s and you purchase power from Portland General Electric, there is a prohibition on you reselling that power to someone else. Now that statute does have a provision in it for electric vehicle charging and exempts electric vehicle charging stations from falling into the regulation of PUC. Other issues include off-peak charging incentives, metering issues, data collection issues, battery deployment, utility investment in batteries, and stranded cost issues. We are an economic regulatory agency who sets rates. We have a stimulus grant to hire some utility analysts to try and avoid becoming a bottleneck to doing these innovative things. We’ve got an investigation open and we would love your input on what issues need to be tackled.

To develop rates that encourage off-peak charging could be perverse based on the incentives and objectives we have here because of the mix of our nighttime fuel supply. Do you have any time of day related carbon analysis that has been done? Many base load power plants are coal. **Response: (Galbraith)** That information could be gleaned from utility integrated resource plants. There is a perception out there that you need to distinguish between the generator that is on the margin and the generators that are just running around the clock. And your point is that there is a lot of coal fire generation that runs 24/7, that is just always running. But, if you are looking at what the marginal resource is, for the majority of the off-peak hours, it is still a gas-fire turbine. It does not mean that coal is not running. The coal is running, it is just not marginal. It is not what will be turned off next if you were to decrease that.

That cautions us about treating different fuels different ways, because the next new marginal kilowatt hours may be different than our base load characteristics of the carbon in our petroleum and so we want to make sure that we are not always looking to that next new marginal, but we are looking at the carbon contribution currently. **Response: (Galbraith)** I think you want to look at carbon intensity at different times at different seasons of the year.

How much non-intermittent resource needs to be added to support the intermittent, because that in some ways may represent future marginal supply. **Response: (Galbraith)** It is an issue that has been under discussion for several years now and it will continue to be under discussion. So it really goes to how much flexibility, because what we are talking about here is being able to ramp generation up and down when the wind is either falling off or rising. We want to go in the opposite direction of the intermittent resource. How much flexible generation do we currently have and when might we run out and when we run out what do we want to add to get more. In my mind, those are the three questions and the answer to any of those questions is still unresolved. We really do not have a real clear sense as to how much current flexibility we have in the existing system. Bonneville has taken a look at it and said they are getting close to the point where they are going to run out on their system. But you need to remember that Bonneville has the vast majority of the wind on its balancing authority today. There are other balancing authorities in the Pacific Northwest that have not reached the level of wind penetration that Bonneville has. It is an open issue as to how much flexibility we currently have, how close we are to running out of it, and what we need to do to get more in the future.

To put this in context, with 11,000 cars at 130-140 kilowatts a piece, if they were all charging at once that is 1.4 megawatts, that is a very, very small proportion of our average statewide connected load.

One of the electric utilities about the effect on rate payers of added capacity in order to support the added load from electric vehicles. Specifically if imposing added load costs across from the base rate payers
and whether that would allowable and how that would be balanced and whether there would be rule changes? Is PUC was doing investigation into that issue and how to resolve it? **Response:** (Galbraith) It sounds like you are referring to a provision in our statute that is called the The Used and Useful provision that means the investments by the utility, if they are going to be recovered in rates, must be Used and Useful. There are two aspects to the Used and Useful situation. The traditional application of it in utility regulation is that at the end of the investment’s life it comes out of rates when it has run its economic life and is no longer useful. I think the application of it in this case would be at the front end of the life, where the utilities make some initial up-front investment to kick start electric vehicle adoption. Get the charging stations out there, take care of the range anxiety and I think that people are wondering if the Used and Useful standard is going to be a barrier to doing that. In other words, if the stations are put in and you do not get a large adoption of electric vehicles and the utilities are trying to recover those costs, is that Used and Useful standard going to prevent that.

- Utilities have an obligation to serve on a peak day because wind is an intermittent resource they have to back up every megawatt power of wind with something else. From a peak day perspective, wind delivers no energy from a planning perspective. I do not know if that is how every utility treats it, but that is one approach to the whole notion of how we back up these intermittent resources. To your question, what other resource is there scalable available to utility than natural gas? There is no nuclear, coal, and probably not much hydro. What are going to add for capacity? **Response:** (Galbraith) I think you are correct that our options are becoming more and more limited on what we can add for capacity. I think that for the short term you are talking natural gas resources. There are other options out there. People are taking a close look at pump storage and other resources, but they have very long construction lead times. It is not something that you can bring on line the next two or three years, but more like 10, 12 or 13 years. On the other point about what for every megawatt hour of wind capacity that you have, you need to have a backup; I do not think it has to be megawatt for megawatt. It does not have to be equivalent, because there are some utilities that are currently surplus on capacity or they are already short. It is really the surplus sources that are the most interesting, because they are the ones that you don’t have to add megawatt for megawatt. They already have a cushion in their system.

- Say demand could stay still for a minute. Adding wind does not demand more capacity. It is actually increasing capacity. What might have been base could go to firming up a renewable or an intermittent. If we can get a cap on that demand, then adding wind does not build to it. You are subtracting more than you are adding.

- How will you temper any of your estimations for computation between electric vehicles and hybrids, and what if people say they are very likely for my next car and, then they do not buy one? **Response:** (Beard) It is a great question and Portland State in partnership with a number of folks is trying to understand the difference in the sociology, the anthropology of these cars. So if you turn around and you get a battery electric Nissan Leaf that goes 100 miles, it may not be ideal to then have to use an internal combustion engine to regenerate power to the battery, but it is a lot less worse than running 100% combustion. We do not know yet what the use cases are and how the market will respond, but we are simply trying to give our citizens choices and learn what makes sense. We are going to jump heavily into light duty urban freight mobility as well.

- How collated is this to the uptake curve of hybrids? In Oregon’s history, hasn’t the hybrid market share satiated some of the enthusiasm for the electric vehicle? In addition, if we have a six-year turnover, aren’t those people’s appetite for next generation technology met? **Response:** (Beard) I am going to qualify it by saying, I am only speculating here. But, because of the powers of natural selection, the early adopters who bought Prius in Portland and elsewhere in Oregon, we are beloved by Toyota. They think that Portland is the coolest place in North American. The Nissan people will turn around and say you know
what in our polling we found out that there is a lot of motivation to go from a hybrid vehicle to a pure battery electric vehicle.

- There is interest in electric vehicles in rural Oregon.
- DEQ did similar calculations as far as projecting high and low estimates. If we were to hit 20% new vehicle sales by 2022 and we went straight up from zero to 20% in these sales, I (Dave Nordberg) come out with a figure of about 129,000 vehicles on the road by 2022, which is not far off from his high estimates. On the low estimates, if we went to 5% of new vehicle sales by 2022 that would seem subjectively to what might be a conservative approach to a low number of electric vehicles. That is highly subjective.
- How much gas is currently available and how many natural gas vehicles would be available? **Response: (Campbell)** Natural gas is distributed throughout the country. In 2008, we went from 120 years of proven reserves to about 200 years of proven reserve due to the efficiencies of being able to pull and extract that gas out of the shale.
- Due to a new production technology that gave access to these vast reserves of shale, everything is on its head in our industry. We are not talking any longer about a resource that is in short supply, but rather one that is clearly abundant, clearly available, clearly domestic, and clearly North American produced.
- What safety issues are there with natural gas used for transportation? **Response: (Campbell)** Natural gas vehicles are very, very secure and safe. Every three years you have them inspected, because you are fueling with high-pressure systems.
- Shelf gases might have indirect land use affects or impacts that have not been assessed on a carbon basis. In addition, water use has rarely been addressed. The other issue is if there is so much shale around and it is $6.00, how does that biomethane play practical if it takes $8.00 to get it to market? **Response: (Campbell)** When you are talking about the contamination of aquifers it is not even at the same drilling level. The depth of what we are doing is vastly significant. You do not have that kind of cross contamination of water with shale exploration. There is water used, but the industry is reusing about 60-70%.
- If shale gas costs $2.00 more to get it out of the ground, the assumption that the cost has no energy content to it, is curious. I just want to see the math. **Response: (Campbell)** I think that a fact that we have realized or recognized is so much gas that the price of the market went down to $4.00 and could possibly go down to $3.00. However, then the price will rise back up and you will see the race go and you will see the price go back down again.
- A headline in the Wall Street Journal about a week ago says that the Energy Information Administration has not been collecting shale gas production data all that well and that the price of natural gas may be depressed because of that. We have two gas experts here. Is there a shale gas bubble that is about to burst here? Are we about to learn that the Energy Information Administration has been dramatically over-estimating shale production and we are going from $4.00 gas to $6.00 gas in matter of weeks? We went down once. Are we going back up? **Response: (Campbell)** I think the Energy Information Administration has been a horrible agency in terms of projections. I am not worried about one article or what the Energy Information Administration thinks in terms of what this country has in terms of supply because if you look at what is being produced and the ability for us to deliver on that shale; I think that the data will show otherwise.
- Just to be clear, it was not the Energy Information Administration that discovered the problem. These were Wall Street analysts who went to the Energy Information Administration and said you are over-estimating shale gas. **Response: (Campbell)** I think it is important to understand that some of what dictates prices is the perception of how commodity is available for delivery in time and that is part of
what Energy Information Administration is talking about as revising those procedures for making those estimates. But probably a bigger part of what dictates commodity prices and indicates natural gas and others is what is actually available and that has not been changed based on Energy Information Administration says was produced last month.

- Is there any way we can sense of a possible estimate for the year 2022, how many we might expect in the state? **Response: (Campbell)** I would be more than happy to provide those same principles to Oregon and show you the estimates.

- Committee had no objections to leaving hydrogen out of the compliance scenarios.

- There is real potential for LNG, especially for long haul trucks. What kind of incentives are available?

- It is reasonable for Oregon to expect that there will be, that some contribution will be made, so in the moderate case I suggest that we add LNG.

- Todd Campbell agreed to pull together estimates of use in Oregon for CNG and LNG.

- I would like to see that curve that was projected collated with the market implementation or adoption of hybrids in Oregon. The adoption rate of hybrids could indicate a likely adoption rate similar for an electric fleet.

- The high estimate ended up at about 5% of the fleet by 2022. How does that compare to what the Northeast states came up with for their high estimates? **Response: (DEQ)** Theirs was actually a total of 8.8%, 4.4% of plug in hybrids and 4.4% of full battery electrics.

- This projection from George Beard was conservative on electric vehicles. However, they are so low carbon it seems like we should have a case that is optimistic. In addition, I don’t know whether the 5.5% is optimistic enough. California used then about 7-8% in some scenarios. They looked at low and high penetration scenarios.

- You wouldn’t want to have a compliance scenario that assumed more of a fuel than you think could possibly be produced cause because it wouldn’t be a realistic scenario. We are just trying to find how much of these different fuels, low, medium and high cases so that we can put together those different combinations in realistic compliance scenarios. We want to make sure they are all possible. You do not want to assume the high in every single scenario for the same fuel.

- We are looking at California and the Northeast who have not implemented yet and we are saying that their estimates are the best we have. We may have a couple of people that are qualified to talk about this stuff. And we are using that to build estimates. It seems like we ought to get some qualified techs that have some expertise in this area to develop this kind of data. It does not seem like this is a robust process.

- Nobody is going to know for sure how much of these fuels can be delivered, it depends on so many factors that cannot be forecasted. We are going to do an economic analysis on these five different scenarios. One is a high electric future. One is a more natural gas future and one is more of a biofuels future. We are seeing different ways of meeting this rule and then we will do an economic analysis and we will have a hired expert to do that analysis that will tell us what it would cost to deliver this. We just want to hand them five scenarios that are within the range of plausibility. Yes, we are going to be putting together five scenarios and they have a 10% reduction.

- **CARB:** If I may say, I think you have plenty of information to do an analysis of different types of scenarios that you are talking about. I think you are in good shape to put together realistic scenarios that might happen in 2020.
I am more comfortable with numbers that we heard today. If we were going to pull from the Northeast or California then bring those numbers in here for comparison. I am more comfortable with going with what we heard today as far as that high estimate.

I do not disagree with that perspective. It is just that these numbers from today are based on business as usual. We are adopting low carbon fuel standards based on a 10% reduction and that will provide an incentive that does not exist today. If it turns out that electric vehicles are the cheapest way to meet the standard, use of them could increase beyond business as usual. If we are evaluating five different compliance scenarios, we are not determining what is going to happen. We are just saying, what would it cost if it went that way?

It seems to me that there ought to be one scenario where you push electric as far as you can and see what happens. If 20% of the vehicles manufacturers are going to produce are electric, and that is without us having a low carbon fuel standard, we could predict higher numbers of electric vehicles. Although we do have a low emission vehicle requirement that is driving that as well.

Car manufacturers move slowly as far as bringing production into line. A new vehicle takes eight years from design to production. Even if with a very sweet incentive, I think the manufacturers are still going to be slow to respond to this. So what is the balance with number of vehicles vs. the incentive? I would like us to to stick with what we have seen and understand. In addition, if we are going to pull something out from the outside in then just show apples to apples.

One of the five scenarios ought to push the envelope on electric beyond 5% electric vehicles.

Well I thought the presentation today was sort of pushing the envelope.

I am concerned about the push on the electric side under a low carbon fuel standard. If you want to have an electric car program, the most efficient way to do it is to have an electric car program.

Instead of seeing five scenarios with one thing maxed out, I would like to see a scenario with moderate in it.

I am comfortable with having a scenario that contemplates a more aggressive adoption of electric vehicles, as long as there is also a scenario that contemplates more aggressive adoption of CNG as well. All you are really doing is defining the jaws and then everything in between is what is really going to happen. Somewhere in between your lowest scenario and your highest scenario is where reality is going to hit.

**CARB:** I would say that the objectives of the scenarios are twofold. The first is to say that the low carbon fuel standard is feasible. The second objective is to estimate cost. It is not to promote one technology vs. the other.

That is the main point. We want to show a balance. We want to show what it would cost if we invest in that scenario. We just want to make sure all of those scenarios could possibly be implemented and to see what the contractor would assess the costs. In the end, we are not going to mandate any of those scenarios the market will determine it in the long run.

The legislature may choose to adopt policies that spur one development and in order to ensure that a mandate is met, but that is not the problem.

DEQ needs to show the logic behind how you reached the numbers in the five scenarios.

**Summary of written comments from advisory committee member or alternate April 16, 2010**

With regard to accounting for the market impact of diverting biomass feedstock and specifically, the Lane County Council of Governments’ efforts to find a use for excess agricultural bio-material. One
aspect of LCOG’s efforts that was not brought up was LCOG’s plans for four small scale biomass power projects along the Willamette Valley. If completed and brought on line, those projects would have a demand impact on biomass feedstock in Oregon.

- The rate of EVs by 2020: Based on George Beard’s presentation, the outer-most optimistic number of registered EVs on the road by 2020 would be 288,000 out of a projected 4.4 Million registered vehicles. I calculate that to be a 6.5 % EV penetration into the Oregon vehicle market for a high estimate scenario. As I said at the meeting, I’m not comfortable with blindly adopting a Northeast or California rate without first seeing why there is a difference, but even then, have those other rates been proven more right or wrong than Mr. Beard’s attempt?

- Under Commercialization Status, the paragraph “Additional infrastructure could be needed to supply electricity for transportation….”, the word “could” should be “would” because I don’t see how there would be a possibility that you wouldn’t need additional infrastructure with more EVs.

- Under Commercialization Status, the paragraph “Electric vehicles have been around for over a hundred years but have not become mainstream due to range and speed limitations.” Is there research supporting this conclusion that technology limitations and not other market competition factors allowed gas-powered vehicles to prevail over time? I’d like to better understand this context to give me a better understanding of what prospects over the next ten years EVs have when competing against other types of vehicles in the marketplace.

- Under Commercialization Status, same paragraph, “These new technologies are currently expensive, but with mass production, costs could come down.” I understand the expense comes from the use of more rare components so I don’t understand how costs would come down in a marketplace of scarcity especially with more demand from EV producers. Also, comments on page 48 regarding Product Barriers appear to contradict the view that “costs could come down” in the next ten years because the progress of battery technology over the last several years has not been analogous to Moore’s Law and computer chip development. So, I’m led to conclude that over the next ten years, battery component costs will not likely decrease and battery technology will likely progress slowly. If there is information available to better inform my conclusion, please share that with me.

- Under Commercialization Status, Infrastructure Barriers, the paragraph “Public investment might be necessary to help build sufficient public charging infrastructure due to the low cost of electricity.” The present state of charging infrastructure leads me to conclude that we “Public investment will be necessary,” and I don’t agree that electricity will continue to be “low cost>” Also, the sentence “Fast charging can be expensive to install”—I’m not aware of a fast charging station that is cheap to install. It’s at a voltage that necessarily carries safety issues which means more costs for safety, in addition to the cost of the charger itself.

Summary of written comments from advisory committee member or alternate May 29, 2010

- We’ve never considered IMPROVING gasoline aside from ethanol additives. I know we've talked about other sustainables....various alcohols..but have we REALLY looked into verifying alternative additives or aimed at re-formulating standard gasoline?

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5. Compliance Scenarios

[Type text]
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- There is a soft spot in your vehicle miles traveled (VMT) estimates for vehicles between 10,000 and 26,000. Your estimates of vehicles 10,000 or less are good, and a good estimate of vehicles 26,000 lbs and up.

- You might want to talk to Carl with EcoNorthwest. He’s been analyzing DMV motor vehicle carrier data.

- TriMet announced that they are going to be using CNG, so there should be some additional CNG in the business as usual case. **Response (TIAX): We’ll take at TriMet populations and see if we need an adjustment. We will also look at what is in the model for diesel hybrids.**

- Regarding biodiesel requirements: Although I think this is the right approach, I just want to make a point that the reason why we are not shifting to the 10% or 5% statewide is generally there has been a movement away from biodiesel and toward the low carbon fuel standard because of the problems associated with accounting for greenhouse gases or for a number of other factors in addition to some economic impacts. So there is an inherent political trait out that has been made to switch to this, but if we didn’t pursue the low carbon fuel standard we would have had a 10% or 5% standard, although this is probably why I approach this for not pursuing the 10% or 5% I think the point should be noted that the low carbon fuel standard is here because we are not doing that.

  - Other committee members disagreed with this statement.

- The concern for me is the E15. For business as usual are we taking a stance that business as usual assumes no regulatory change between now and 2022?

- In the larger perspective, it seems like we are projecting this for no changes in fuel prices and no changes in this. We are projecting it for the one case that is not going to happen.

- Say here is a scenario without a change and then here it is with E15 or here it is with whatever. **Response:** If you think about how it would affect the analysis if we assume that in the absence of the low carbon fuel standard most likely the legislature would do something else over the next ten years. If we assume those things it would be a baseline that would reduce the estimated cost of this program. And if we go the other direction and assume things are going to be repealed then we are going to overestimate the cost of the program. So it’s just a point comparison that we say from business as usual today assuming no further action how would this program stack up. I think in the end when we look at the low carbon fuel standard as compared to the business as usual case, we will still be able to say that in the absence of low carbon fuel standard probably something else would have happened in that business as usual case too and maybe overestimating the impacts of the program. But we still have to compare to some fixed baseline, I think. The traditional map of this business is usual to assume what’s on the books today. So we can have some qualitative context for it when we present the final report, but I think we need to compare it against the business as usual.

- What is of concern to me is where this continuous downturn economy lies in all of the changes. When I look at numbers and I hear these percentages, those of us who have to lobby for the majority of our livelihoods, we know we are going to be in for a difficult session when it comes, because everybody is going to be looking at how the economy has not improved or changed. And when you were talking about the number, the EV project and those things, I think about if people still aren’t working they are not going to be buying anything. Folks are holding on, businesses are holding on, letting their fleets. And so as we continue to throw out these scenarios, I hope we don’t lose sight of what the economy looks like and ultimately what businesses are looking like. Because all of these things can’t happen if people don’t have any money to drive that change.
I know a lot of the things that we make decisions based on are projections, estimates and all that kind of stuff, but here we are building estimates based on estimates. We are analyzing what we absolutely know is not going to be correct. So where I’m having the problem is we know, for example, what fuel consumption was in 2010. We know how much biofuels and all that kind of stuff. Why don’t we analyze historical data and then plug in what will happen with low carbon fuel standards and make that the basis for our economic analysis, because we know those numbers. We know that we have to reduce 10% low carbon per gallon and we know how much fuel was burned in any given year and we could then make the economic analysis based on that, instead of projecting to 2022 when we know that we are going to miss the bus for all the reasons that everybody has said.

So you want to compare 2022 with a low carbon fuel standard to 2010?
You can’t compare consumer fuel expenditures in 2022 to consumer expenditures in 2010, so you have to make some kind of projection out to 2022 to make a comparison.
I don’t understand why we have to make a projection or why we can’t just use a base historical year and analyze that based on 10% reduction in carbon per unit on that same historical data. That’s what is puzzling me. That to me is the baseline and then you can apply economic forecasts in and say if this happens, if the economy recovers or doesn’t recover then you can do it just based on the economic projection, but you’ve got to solve it based on the projections. We can say we sold 10 gallons of gasoline in 2010 and now we are going to prepare than 9 gallons of gasoline and 1 gallon of something to get a 10% reduction. I know this is more complicated than I am making it, but my point is making it more an actual historical data instead of projecting 12 years in the future and using that as your baseline. Because that guarantees that whatever we say is going to be inaccurate. I guess that’s my question.

I’m not sure if I quite understand the analysis that we would do. I assume what you are saying is that 2010 could be our horizon year and 2000 would be our start year because that would provide us historic data, because we would know the fuel used in each of those years and then we would implement…or for analysis sake, we would do an analysis of what if we had a low carbon fuel standard starting in 2000. The problem is that we have to use the type of fuel that we are using in 2010 for this analysis and so we can’t just pick any random decade.

I understand I think where you are coming from, but I think Vijay explained it fairly well at the last meeting. He was talking about how all costs of compliance analysis that will fit in one kind of mold, which is really I think comparing the business without the regulation to the scenario with the regulation. So that is the only way you can get the cost differential and what is the regulation cost.

2010 is in there. That’s where we start with the vehicle maxes and that’s where we start with the fuels, but you then have to project forward to 2022. Because, just to take the simplest of examples, the RFS2 is going to bring us a lot of biofuel that whether or not we have the low carbon fuel standard and we have to look at the differential cost of the low carbon fuel standard requires over and above that and what else is there. You know gasoline is going to be affected by the changing Cafè standards, so you can’t use 2010 by itself. You start with it and you project forward and say what would this look like in 2022 without this regulation. So I think we are doing what you are saying, starting with the actual 2010 data and then adjusting it for everything that is going to change between now and 2022.

I just wanted to say that modeling approach using the baseline 2010 and then developing out the populations with different curves for fuel adoption rates of these different types and the vehicle adoption rates by technology and so forth is the right approach. That is the standard economic
comparative analysis model. And I think having the economic data available for people to review on an annualized basis of the differential between what would be business as usual and the model that we are projecting that gets us on the curve to comply at 2022 is going to be quite sufficient. You see the same type of analysis no matter what type of project you are looking at. If you were going to be building a bridge across I-5, you would be looking at traffic line going to 2022 with and without grids. So you are going to have to forecast what business as usual cases in order to know what type of project you are looking at.

- I think part of what we are hung up on is this phrase business as usual - is the current context, the current regulatory and statutory construct at the moment that you are setting the baseline, which you assume is going to change. And there are some ways that you can predict that it is going to change and other ways that you can’t. You know that it will change, but you are going to say during the next 12 years if that did not change this is what the baseline would look like. And the other thing that I hear Bob saying is why don’t you start by, help me if I’m wrong, is starting with just the historical data, but then adjusting that historical data in 2010 to reflect what the fuel mix would be if you had a 10% reduction in 2010 in carbon intensity. So I think that is what you are saying, is use that then as the baseline. So starting with the 10% reduction and then calculating what affect the rule would have. And I’m not sure how you would get there, Bob. I’m having a hard time wrapping my head around the mechanics.

- I always think of it as without regulation as opposed to with regulation.

- I definitely know if that is the case that where Exxon Mobile is going to be having to build out infrastructure and where there are economies of scale and how that matches up to fleets to make sure that a certain portion of our cars are going to be E85 ready, but maybe the economies of scale in California are different. I’m not sure anybody around this table has to be able to make those clear cut decisions. I think that is kind of a decision that needs to be made based on the best experience of the economist and that’s that they can provide what generally has happened based on the historic trends, although this has never really happened, but based off the experience or theory of how this may play out or what we should do here.

- You have described for us the boundaries and you’ve indicated ones pretty conservative and the other is at the other end of the spectrum and my question is, is there a rational way to strike the middle? That you are familiar with and comfortable with and if so it, we’d like to see it. Otherwise, my judgment would be go with the conservative estimate and assign all the costs to the regulation. I mean people ought to know what these things are going to cost. That doesn’t mean it’s not going to happen, but that infrastructure is going to need to get built out and it’s going to need to get built out because of our LCFS. So why wouldn’t go with, in the absence of anything in the middle, why wouldn’t you go with the conservative estimate.

- When WSPA made their presentation, their point was that RFS2 is going to bring us something comparable to the low carbon fuel standard. So the assumption was all centered in Oregon, but it’s going to be out there in the country that we are going get this much ethanol produced if we have an E10 wall, there is going to be E85 infrastructure built somewhere in the country. So assigning all those costs to low carbon fuel standards really over-estimates the cost of that standard. If we didn’t adopt the program, it was going to happen anyway somewhere in the country.

- One way we may want to approach this is that we are going to have different analyses and we can look at Washington, we can look at NESCAUSM, we can look at California, and we are going to do our analysis, but if they are all based on different assumptions we can still tie them together and say if you made this assumption these are what you would get and with assumption that is what you would get.
There are two principle variables and one is that the RFS2 will drive the E85 infrastructure development because the market will have to take up more than the E10’s blend wall will provide for. We can’t attribute that all to the Oregon low carbon fuel standard. It’s not practical and it is not a defensible case in and of itself. In addition, all the data research that has gone on at NREL and Argonne and actual real legacy fleet vehicle testing has proved that the E15 blend stock has got legs under it, politically potentially, and if not, at least, at E12. So we have to keep in mind that it is highly likely that standard will change during this term of our LCFS build out and we ought to at least address it. And if it is at the mid ground, is it? That’s a good question, but I don’t think we can attribute all ethanol above an E10 blend wall causing additional infrastructure costs to be LCFS dependent.

That’s why we’re thinking that we should stay with the E10 blend wall. That’s the current regulation. Washington is looking to do 15. So that will be good that we will get to see it both ways. Because, if we stick with E10 then the questions is whether we are going to get less than our proportionate share of ethanol in the base case or whether we are going to assume that there is going to be E85 infrastructure built to absorb our full proportionate share. And I guess the question I would ask is if Oregon’s got the same proportion of flex fuel vehicles in our fleet out there as other states do, what would be the economic driver for the fuel distribution that oil industries provide less than the E85. That would be the questions. Is there some reason people can think of why Oregon would get less E85 infrastructure than other states would get if we have roughly the same proportion of flexibility? If we can’t think of a reason, then we should just assume that we are going to get our share of E85 infrastructure.

Doesn’t Oregon have a historical evidence of early adoption of other fuels, so I think if anything I would say we would at least have our proportionate share of E85 vehicles here or more.

I have no reason, based off my experience and knowledge, to think that we would have a different proportion of ethanol and biomass-based diesel than any other state. One factor is what the scale is for building infrastructure in other states to be able to meet the E85. And I think that question is a smaller, would probably have a small impact on what our proportion would be. And so, I would lean towards something closer or really close to where the proportionate share was. We may want to discount it by some factor. So if we do like a 5% reduction to proportion shares or something like that. We have to come up with something that makes the most sense, that represents what a regulatory environment would be if we don’t have low carbon fuel standard. And it’s likely closer to the proportionate share, but I don’t have expertise to know exactly what that number is.

Perhaps states that have higher volume gas stations might have a greater ability to put in a second tank.

Yeah, I don’t think we will hit our proportionate share, just based on ability to permit and do things, because the facilities that we have now much less expand, based on population size. I’m not saying that we won’t get some of it, but I think there are a lot of other places where you could make heavy infrastructure investments and serve a far larger population for that capital.

Another piece of data that would us decide is might be to look at the distribution for our gasoline stations, how many gallons they sell relative to say New York and see if we are average or below average or above average. And maybe use that somehow to factor us off of proportional case or something like that.

I don’t know if you have talked to any of the terminal folks? What kind of constraints are there in those terminals that serve basically the entire state.

Probably every other state has similar problems, so we have to do a relative comparison. If you have this much volume to move, it’s got to go somewhere and if we are significantly different, because let’s say we are an average of so many gallons per month, then in the bigger state the typical gas station sells twice as many gallons. One they can probably afford to put a tank in, where we can’t.
• With regard to ethanol staying in the Midwest; they already have a high proportion of E85 use. And then the question is, is what is their fleet capacity to take more E85. So, there are so many factors here. I think the approach of looking at gasoline station throughput is a good one.

• Assuming that other states are in the same boat there would be more blending facilities. There is no reason to think that biofuel and ethanol use wouldn’t proportional here.
  o I don’t think we are in the same situation, because states are unique.
  o Most states have refineries and this isn’t a concern.

• We should find out what capacity the blending facilities are and factor that into the analysis.

• Before we go there, I’m unclear about where we left the discussion around ethanol. I would like to have seen maybe an option or two developed that our technical experts felt are defensible that we could then ask questions about and challenge and arrive at. But, to be just kind of given the option of two bounds, neither of which is acceptable, what do you think works? I’m ill-equipped to respond to that question.

  **Response (DEQ):** Here is where we left it on the ethanol, we said it’s going to be somewhere in between the two and we are going to look at the through-put average for a gasoline station in Oregon and compare that to the national average through-put and come up with some kind of a factor that would be applied to that difference. And that’s sort of a technically justified cut, I think.

• For CNG light-duty vehicle projections, NGV Association might have numbers or studies. California is pursuing CNG. **Response:** When we talked about fuels assessment, we decided to use Energy Information Administration projections on the light duty CNG. That’s why you don’t see a higher light duty CNG, because of that conversation that the committee had.

• If we could find defensible, rational numbers around light duty CNG projections, I would encourage that. Clearly, I’m dubious that those numbers exist with any depth, or that any robust numbers exist in that regard.

• On heavy duty LNG – why is heavy duty LNG not considered? In California, we are seeing the natural gas favor the LNG engine compared to the CNG.

**Summary of written comments from advisory committee member or alternate July 21, 2010 regarding draft compliance scenarios presented July 7, 2010.**

• The economic impact of scenario assumptions will drive scenario viability both within a scenario (for example the economics will drive the split between cellulosic ethanol and other low CI ethanol) and across scenarios (the Cellulosic (Scenario 1) and stated Max EV and Cellulosic (Scenario 4)). Will DEQ carry out a “loop back” to revise scenarios due to economic impacts as part of this review?

• Oregon Distillate Use data contains Farming and On-Highway. We understand that farming and logging trucks (part of the on-highway fleet) will be exempt from the Oregon LCFS. Will these volumes be removed?

• What is the 1000 EV project and who is paying for it? Is the funding for this project secure given the current economic climate? Is the increase in EVs as a result of this program reasonable, what cost assumptions are used? The EV:PHEV ratio is increased from 1:99 to 1:6, this seems to be a large ratio increase. How realistic is this? Upon what assumptions is it based? We note there is an assumption made that HEV, EV and PHEV sales in Oregon will be twice the national average. We question where this assumption came from and how realistic this is.

• VMT – Will this be adjusted for pass-through trucks?

[Type text]
• Light Duty VMT is noted as being adjusted by a factor of 1.23, essentially a force fit. As the fleet changes through the modeling period of 2022 and fuel economy changes are overlaid, will the adjustment skew the analysis?

• Medium and Heavy Duty is noted as in a state of flux. Will farming and logging trucks be removed from the analysis?

• The BAU case considers the EPA Analysis Primary Control Case as the basis for volumes on slide 17 and 18; however given the EPA’s recent need to modify cellulosic biofuel requirements, does this represent a reasonable basis? The technical, market and economic viability of the listed renewable fuel categories are not equivalent, and adoption curves for these materials will vary. The relative volume estimate of Brazilian ethanol seems very low given that it is a fuel which is readily available today. Similarly, the cellulosic portion seems high given the technical and economic hurdles of seeing this category in the marketplace within the analysis timeframe.

• As discussed with respect to slide 17/18, the Imported Ethanol adoption curve appears to be very low in the early scenario years despite its current availability and its proportional volume is viewed as unrealistically low. By contrast, the combined cellulosic ethanol and cellulosic diesel seem overestimated compared to imported ethanol. Were credible estimates of technology availability used to create these adoption curves and who provided these estimates?

• As the EPA has yet to issue a waiver for E15 and has indicated that it may only grant a partial waiver for E15 in light of the fact that older vehicles and most existing non-highway engines are not compatible with E15, it is viewed as not reasonable to use an E15 assumption for the BAU case nor to define any FFV E85 assumptions. The FFV E85% of 35% VMT appears unrealistic and should be tested against current Oregon State E85 supply in order to level set any FFV projected estimates. It should also be noted that while FFVs are currently produced, this continued production is not required by any regulation, and it is not clear that a large and growing FFV fleet will be part of the Oregon vehicle population in the years modeled.

• In addition, we question whether there is a mathematical or assumption error regarding the FFV/fueling %.

• The E85 infrastructure investment should not be part of the BAU case as the FFV E85 VMT assumption is viewed as overstated.

• EV and PHEV EER Assumptions - The use of EER assumptions as used by CARB in their LCFS analysis as a starting point for this Oregon analysis is a significant concern. CARB staff did not make any adjustments to the fuel economy estimates of EVs or conventional vehicles to reflect the impact of actual (as opposed to laboratory) operation. A recent study by Argonne National Laboratory (see http://www.transportation.anl.gov/pdfs/TA/629.PDF) has found that real-world EV operating conditions have an important influence on well-to-wheels GHG comparisons relative to conventional gasoline vehicles. Another important factor is ensuring that the EV is being compared to a gasoline vehicle of equivalent performance. As data become available on real-world energy use by EVs and PHEVs, it is imperative that the EER value for EVs be re-evaluated.

• Light Duty Diesel – Oregon is proposing to separate diesel LCFS compliance from gasoline compliance. We believe that a combined pool of diesel and gasoline gives a more technically accurate GHG reduction opportunity for Oregon. The GHG benefits of a light duty fleet change from gasoline to diesel will be neglected in the proposed separation of gasoline and diesel compliance. In addition, it will not support the technical opportunity for Original Equipment Manufacturers to market advanced clean diesel technology in the North American market, nor give incentive for fuel providers to increase the retail presence of diesel fuel to facilitate this market shift.

[Type text]
• We would like to see the overarching crude oil price assumptions and intended sensitivities to be used for the analysis.

• The Proposed Compliance Scenarios are separate gasoline and diesel pools. In keeping with the GHG of LDD replacement of the gasoline fleet, we feel a one-pool scenario is needed. It was noted at the July 7th meeting that Washington State is proposing a one-pool approach, and we encourage Oregon to adopt this approach as well.

• The listed scenarios do not appear to have a basis in their overall technical or economic likelihood. We believe that realistic scenario boundaries are important so that the JFA economic analysis is not created with “boundaries” which are not balanced by market and economic possibilities. As such, the scenarios need to be built from the bottom up using credible estimates of technology availability, and recognizing competing demands for available resources.

• Draft Scenario 1 – Brazilian ethanol is viewed in the presentation as unrealistic within the 2022 timeframe. In fact, Brazilian ethanol represents currently available product that will deliver a significant CI benefit when compared with the other conventional ethanol types listed in this scenario. As cellulosic ethanol is technically and economically unproven in the market, the use of this material to balance the scenario seems tenuous. What is the production capability assumption of cellulosic ethanol for this scenario based on? Are credible estimates of technology availability used to derive these?

• Draft Scenario 1 also lists E85 use in order to balance the scenario, yet we question the basis for this, given the need to increase E85 infrastructure and assume E85 fleet continuance (or expansion).

• Draft Scenario 2 – Why is 189 MGY of cellulosic ethanol viewed as moderate? On what assumptions is this based? What is viewed as high E85 VMT? In what year? What fleet assumptions from OEMs are used to estimate these?

• Draft Scenario 3 – We do not see the relevance of a no-ILUC scenario.

• Draft On what basis does Scenario 4 define an EV population of 240,000 and PHEV of 288,000 by 2022? Why are these two populations so close when the anticipated cost of EV home-based recharging stations is so high – what economic analysis has been done to ensure that this scenario has a likelihood of being adopted? We believe it would be preferable to derive a more market based estimate of a high EV world with assumptions based on vehicle manufacturer market estimates or similar information.

• All draft scenarios – What assumptions are used in the allocation of the balance of the scenario to Pipeline NG into CNG? This would require considerable flexibility in any assumptions on the CNG fleet. What would they be based on? How does this fit with the balance that also goes to Midwest Soybeans? We would expect that a single balance of the scenario would be preferable and should be allocated to a biodiesel category.

• Why is all Northwest Renewable Diesel expected to be used by the aviation industry? How does this factor into the Oregon LCFS and the diesel and gasoline pools? It is not part of the BAU baseline.

• Draft Scenario 5 – On what basis is the Oregon Cellulosic Medium level of 110 MGY based? On what basis is biogas for CNG estimated as half of unused as Moderate? We anticipate that market and infrastructure cost will determine whether Biogas is directed to transportation or electricity generation.

• Draft Scenario 6 – How is “up to maximum available” determined for Northwest Canola?

• Draft Scenario 7 – Why is 1.5 x BAU in view for the Maximum Natural Gas scenario? Does this align with vehicle manufacturers’ estimates? What are other drivers for this HD fleet change?

• Draft No HD PHEV’s are factored into the scenarios. Could this be included in Scenario 7 as a maximized alternative scenario?
August 10, 2010 Advisory Committee Meeting

- Couldn’t find a way to track logging trucks for their exemption. It’s not really an issue. Number one, it’s small. Number two, they’re going to be using the same fuel as everybody else, because we’re not going to have special gas stations for log trucks.

- There’s a lot of policy discussion at the Federal level about promoting, especially heavy-duty, LNG vehicles, and that’s actually very relevant in Oregon, because a lot of talk about establishing an I-5 corridor from Canada to Mexico based on LNG. Response (JP): LNG populations are pretty low, the carbon intensities for LNG are pretty similar to CNG, and since we’re increasing in all the scenarios the CNG population by 20%, we’ve decided that’s a combination of CNG and LNG.

- Separate out heavy fixed construction because we’re already accounting for it in the off-road vehicles, through Energy Information Administration data. There are no special exemptions for construction equipment.

- Do we see a natural shift from gasoline to diesel going on between 2010 and 2022? Response (JP): Gasoline has declined in 2010 – not a lot, but it has declined at the expense of hybrids. And then diesel, it grows a little bit, but not really much at all.

- Based on comments from the last meeting, we looked at the gas station throughputs in Oregon, and compared it to the U.S. average throughput. It’s quite a bit higher – 524 gallons per day, vs. 489 for the U.S. average. This justifies that comparatively speaking, the gas stations in Oregon have the economic ability to absorb the E85 infrastructure costs.

- I thought I saw something about the EPA now looking at E12 instead of E15 as an interim measure; do you know anything about that? Response (JP): Need to track down that information. The problem with the E15 is that the vehicles from the years 2001 and older can’t handle it. So perhaps the 2020 frame would be appropriate, because those vehicles will be retired.

- Does that matter economically? However you get there with the RFS2 compliance? Response (JP): Economically, if we have investment in E85 infrastructure in our business as usual case, then it’s no increase for the low carbon fuel standard. So if there’s no investment in E85 in the business as usual, then the low carbon fuel standard is more expensive,

- Because the question of blend wall isn’t settled, we’re not putting in the BAU. But we are having to look at it as part of the various compliance scenarios. And we need to do it in 2016 when we look at reviewing the program.

- I think you have to take into account the fact that there is no state barrier to ethanol production, and people will necessarily build wherever they can get the best transportation, best labor costs, best operating costs, and it’s a very real possibility that you could have a lot of ethanol production in Washington or Idaho or some other place, with minimal transportation costs if it’s just across the border. I’d almost do three of them: One where nothing is produced in the state of Oregon, everything is produced in the state of Oregon, and a split.

- The folks who are doing runs of the model, REMI Northwest, will only crank the model as many times as we tell them to. There’s a cost involved in going through that process. We can do certain things with them that don’t require a full set-up of the model, where the model is going to be run one way, and then we only have to change one variable. They might not charge us a full ring of the register for that, but that has to be negotiated with them.

- Are the CAFÉ standards incorporated? Response (JP): They are.
• What is the incentive that we’re assuming we’re going to get people who have flex fuel vehicles to use it? Response (JP): The onus is on the fuel providers and the low carbon fuel standard to sell the required volumes of fuel to meet fuel standards.

• If we do the E15, the VMT shares would have to be? Response (Jeff): It cuts it in half. It goes to 30% FFV miles, as opposed to 60 with an E15 blend wall in 2022.

• In Europe, the way they’re reducing the carbon intensity is by shifting to diesel. I thought the idea of this one pool scenario was that you would have more light duty diesel vehicles, and increase the actual shifting from gasoline to diesel, and then see how that affects the overall scenario. Response (JP): How would we estimate how much that shift would be? How about a 10% market share in 2022? It’s just 6% in autos, so overall fleetwise, that’s not a huge jump going to 10%. What if we just do a 15% increase each year on sales, for light duty autos and light duty trucks?

• For the first time in the UK, in Britain, light duty diesel surpassed sales of light duty gasoline.

• What is DEQ’s position on the NOx bump? CARB is convinced that biodiesel increases NOx even at the 5% level. I wondered if you agreed with that. It even plays into ethanol since even if it is not an ozone issue, the NOx might be. Response: We don’t have a position on it, but it is an issue. We haven’t done that analysis.

• There’s also different refining configurations in Europe that are meant to produce larger quantities of diesel vs. gasoline. Response (attendee): Some refineries can change configuration and others can’t and the degree of complexity of the change will be different.

• If you’re looking at California having their (LCFS) program in place, are we going to see a lot of this (lower CI fuels) going to California that then won’t be available to Oregon?

• Can we resolve the ethanol blend level question? Response (JP): Use it in the mixed ethanol with and without indirect land use change.

Summary of written comments from advisory committee member or alternate August 16, 2010

• The Level 2 residential charging station cost looks low. I think Coulomb, ECOtality, GE and others are in the $2,500 to $5,000 range for materials (a charging station) alone.

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• Perhaps check pricing (all levels, public, private) with Coulomb and ECOtality. They’re both involved with the EV Roadmap project here in the Northwest so their pricing schemes would be directly relevant for modeling.

6. Economic Analysis
December 3, 2009 Advisory Committee Meeting

- How many sensitivity runs does DEQ plan to do when compiling compliance scenarios? From utility experience with integrated resource planning, it’s easier to try to put brackets around upper and lower bounds for most optimistic and most pessimistic scenarios, as opposed to specifying a single number. **Response:** We plan to generate ranges, not specific values.

- California looked at a range of possibilities, including mixes of low and medium carbon intensity ethanols.

- The upcoming change in fuel economy as required under federal GHG regulations will affect the cost of complying with the LCFS. Will this be reflected in the GREET model or in the economic analysis? Also, federal fuel economy regulations will affect EERs which compare the energy efficiency of alternative vehicles to comparable petroleum fuel vehicles. **Response:** Oregon has already adopted low emission vehicle standards, which will be reflected in the baseline for the economic analysis. Mr. Satyal noted the point (about accounting for federal fuel economy regulations) and will ensure the baseline for the economic analysis reflects applicable standards.

- Oregon is required under HB 2186 to take into account changes in drive train efficiencies, which may be different than California’s requirements. If we are partly achieving the GHG reduction goals of the LCFS by reducing the volume of fuels consumed due to power train efficiency improvements, then this must be considered in the economic analysis. **Response:** The economic analysis will reflect Oregon regulatory requirements. The purpose of this presentation is to get input on writing a request for proposals in order to hire a contractor to perform the economic analysis. DEQ will add references to drive train efficiencies and federal fuel economy regulations into the RFP. Drive train efficiency was mentioned in the bill to ensure that the carbon intensities calculated under LCFS program take into account differences between the relative efficiencies of electric, hydrogen, and natural gas vehicles. The intention was not that Oregon would comply with the LCFS by changing vehicles. DEQ and commenter agree to pursue discussion about the significance of the statutory language on drive train efficiencies outside the meeting.

- Impression was that LCFS aims to get a reduction of 10 percent below forecasted “business as usual,” not 10 percent below whatever carbon intensity was when the legislation was passed. Is this correct? **Response:** No.

- Railroads plan to make major changes to their engines over the next several years, which will result in 15 percent reductions in emissions without using biodiesel. They want to make sure these improvements are taken into account.

- Will our state program cause any problems with NAFTA, which will result in more Canadian trucks on our roads?

- There is a need to understand the contributions of other climate change programs already adopted in order to understand the economic impacts of a LCFS program.

- What consumers and businesses care about are changes in fuel prices, not changes in the costs to produce fuels. It’s difficult to forecast how changes in cost will translate into changes in fuel prices - how will the analysis deal with fuel prices? **Response:** CARB found a small reduction in costs, but allowed that all or none of the reduction in costs could be passed on to consumers. **Response (CARB):** In their economic analysis, CARB avoided looking at changes in prices because prices are affected by all kinds of additional factors, not just changes in production costs. **Response (Mr. Satyal):** Oregon is much smaller than California, and hence is a price-taker in the fuel market. Taking this into account, together with price-driven changes in driving behavior and innovation by industries, the factors can essentially cancel each other out with respect to impact on prices. The RFP will include consideration of how changes in
costs will affect fuel prices. If time and resources allow, the contractor could perform sensitivity analyses that would look at price effects.

- Isn’t local supply of alternative fuels a function of prices? **Response (Mr. Satyal):** Yes, and the economic analysis will take this into account.

- Economic analysis needs to account for benefits, not just costs, such as avoidance of CO₂ cost risk under future national or international programs which would impose costs on GHG emissions and public health impacts of reductions in air toxics from changing fuels.

- Will analysis include costs to railroad companies of fuel additives necessitated by use of biodiesel? Even if the fuel is the same price, biofuels may bring additional expenses. **Response (Mr. Satyal):** Yes, additional costs should be taken into account. He would encourage fuel users to bring this kind of information forward for inclusion in the analysis.

- Public benefits, including environmental improvements, should be taken into account. **Response (Mr. Satyal):** REMI as a tool is somewhat limited in this respect, but can incorporate information on related economic impacts. The literature review which will accompany the economic analysis can look at factors which are not easily quantified.

- Will the contractor be getting information solely from the advisory committee? **Response (Mr. Satyal):** The contractor will look at existing published information sources, as well as analyses already performed by other states.

- Will the economic analysis be able to account for supply shortages of biofuels to meet the LCFS, which will influence prices? **Response:** The compliance scenarios will be based upon reasonable projections of how much low carbon fuel will be available. The economic analysis will be based upon the compliance scenarios, so it is important to come up with reasonable scenarios. Also, the statute requires DEQ to build deferrals into the regulations in case expected sources of low carbon fuels do not materialize.

- The analysis of federal diesel rules attempted to look at externalized costs and benefits (such as health effects), and could be a good starting point for DEQ’s analysis of the LCFS.

- Request that DEQ and Mr. Satyal put together a list or matrix of key REMI assumptions that will affect the economic analysis results, perhaps soliciting input on what values to consider for business-as-usual, best case, and worst case. **Response:** We plan to talk about the assumptions in February.

- Process assumes there will be credits that will be bought and sold by fuel producers. Will cost of credits and the trading mechanism be included in the analysis? Don’t we need to know the design of the trading system before we estimate the compliance costs of the program? **Response:** The ability to trade lowers the cost of compliance, so leaving credit trading out of the analysis provides a conservative look at costs. On the other hand, transaction costs would not be accounted for. **Response (CARB):** This is a cost analysis. Since the costs of a trading mechanism depend on the design and are not yet known, CARB left the cost of credits out of their analysis.

- California is spending $250 million per year over the next seven years in incentives to help meet the LCFS. Oregon also has incentives, such as the BETC (Business Energy Tax Credit) that will help toward meeting the LCFS. These incentives show up in the accompanying handout (page 10) as cost savings under the LCFS, but they should in fact be considered as costs of meeting the LCFS. **Response:** The analysis will identify costs to different sectors, such as business and government. Savings to one sector may be a cost to another.

- Calculating the costs of tax credits must take into account long-term public benefits, as well as short-term costs. Analysis of this kind has been done in Oregon on the BETC.
• How much money has DEQ allocated for this analysis, and is it a reasonable amount for a quality product? **Response:** The budget is something over $100,000. Oregon and Washington have received a grant from EPA to cover the economic analysis in Oregon and some related analysis in Washington. **Response** (CARB): CARB has already done much analysis which will be similar for Oregon, and can share their results for use and modification by Oregon’s contractor. **Response** (Mr. Satyal): Oregon’s RFP includes a literature review that will identify analyses and data from other states that will be useful.

• As far as credit trading, it would be wise to consider different assumptions. The worst case is an illiquid market with few credits to trade, e.g. few electric cars entering the market. If there are no credits to trade, then trading will not help ease compliance costs.

• There are historical data and many studies on costs of credits and transaction costs, providing a range of outcomes. **Response** (Mr. Satyal): EPA has analyzed credit trading, and several studies are available from the National Center for Environmental Economics.

• How will sectors be chosen for the analysis? **Response** (Mr. Satyal): The contractor will choose a list of sectors to be included, and then run the list by the advisory committee.

• California exempted certain fuels that are subject to interstate and international commerce, while Oregon’s statute calls for fuels used by agricultural vehicles and logging trucks to be exempt. At which stage in the economic analysis will exemptions be accounted for? **Response** (Mr. Satyal): Probably in the fuels assessment or compliance scenarios, but the contractor may suggest another way to account for it.

• Even though current statute allows certain users to be exempt from the renewable fuel standard (RFS), they are not always able to buy clear gas, so there are other factors at work.

• Observation that the consensus of the group seems to be that the overall structure makes sense, although committee members may differ on what should go into each step.

**Summary of written comments from advisory committee member or alternate December 16, 2009 regarding Proposed Economic Analysis.**

• What will be considered business as usual? The current economy is not exactly “business as usual” with fuel prices depressed due to the poor economic conditions. What is a good comparison to make? Should several “business as usual” scenarios be run?

• Can the analysis be done on a regional basis in Oregon so we can see if there are disparate impacts to the Portland metro area compared to eastern Oregon, southern Oregon etc.?

• DEQ is proposing to focus on the direct fiscal impacts to parties directly affected by a LCFS and on a set of questions developed by DEQ and the committee. I agree that this should be the focus but I would suggest that the indirect socio-economic impacts be mentioned in a qualitative review.

**January 27, 2010 Advisory Committee Meeting**

• Economic analysis should include changes to gas tax revenues due to the increase in numbers of electric vehicles.

**April 15, 2010 Advisory Committee Meeting**

• Are we going to do an economic analysis on biomass availability to show us what is possible, or are we just going to do a technical analysis? It seems to me that an economic analysis would be very helpful, for example for grass seed straw. There is a lot exported to Japan and other places for animal feed, bedding, etcetera, so we would be competing with that economically. **Response:** (DEQ) We need to look at that. I
know in California’s economic analysis, they did look at the cost of feedstock and that certainly is something we will look at.

June 23, 2010 Advisory Committee Meeting

- We do not have the economic models available to include new and emerging sectors in the economic analysis. For example, electric vehicle recharging stations don’t exist here yet – how will things like that be included? There are other sectors as well. It seems like the system looks more at costs for existing sectors than benefits to new and emerging sectors. **Response (ODOE):** We take things as they are but also look at what we want things to be. It will take at least three to five years and that is a guess because public infrastructure has to be designed. The question will come about public aspiring ventures. If it needs to be prepared as an option of low carbon fuel, what is the source, what the base operating sector that it comes from? If the state agrees strongly then maybe an appropriate subset could be put in that account for change and production of fuel that accounts for the sector. So that is feasible. What assumption will have to be made and how you wish to designate it in the model. There are some other sectors that represent emerging pathways. And that would be important to really bring out and bring up… ask the contractor, what sectors you wish to feel there are some emerging economy created that are not looked at in the sector you have given and please highlight and give ideas or comments back to Sue. **Response (DEQ):** When we sit down with our contractor we want to talk about the sectors to be evaluated. Posted online and provided to you is the list of the 70 sectors that are typical for REMI. We would like to get your ideas as quickly as we can so we can talk to our contractor about are there specific sectors for Oregon that you think we really need to include, whether it’s current sectors that just you said are not on the list or emerging sectors. And then are there any questions that you think the analysis should really be designed to answer.

- On the economic analysis, is this where you would consider whether or not certain folks are just not going to supply fuel to the state in certain sectors? We don’t dictate to anybody because we don’t have enough of a market. So basically, one potential scenario is that some companies say it’s not worth it, because it’s only a limited market that’s requiring this. I’m just going to move out of there. We see it all the time with different brands changing, like fuel stations. It is not easy to do in a California scenario because it’s a big market and nobody wants to be out of there. But it is very easy to do in Oregon and that drives the cost up. Is this where you want that information or that kind of questions to be asked? What happens if XYZ Oil Company decides not to sell in the state? **Response (ODOE):** However, what you are saying behind the question is that as the price taker we would model or we would assume in the business of using some conditions or reality or fuel comes in from there and we really want the whole distribution or who is more readily more effective and who is not. What this assessment will simply do is provide a snapshot of who is impacted by how many and what costs they will incur and they will benefit from if they want to explore any of these compliance scenarios over time. So what you are asking for is an exit analysis that is not typically done in this kind of work.

- We talked about what would happen if, despite our compliance schedule, the supply doesn’t materialize on the dates that we need it? We are building into this program the idea of having deferral so if we get to a given year and there isn’t fuel available either because a plant wasn’t built on time or perhaps a supplier decided not to sell to Oregon for whatever reason the mechanism we would use to respond to that in real time in the future would be defer the phase down by a year and to provide more time for the market to adjust. Can the model look at what happens with the deferrals? **Response (ODOE):** There is a way to address that timeline. What time you expect sudden substantive fuels to come online and be available and that would be a way to address some of those issues. That is where I expect the low carbon fuel
supportive technology available resource providers to really give a fair assessment of how long they think their resources will come online. And that can be assessed here.

- Fuel price concerns everybody. I understand that you are going to get results at the level of government, general public, by sector, etc. How much further down are you going to be able to go? Take construction. Will the economic analysis include the kind of equipment issues, modifications, and the costs for changing a largely legacy fleet? Is technology available? At what cost? How far into all that will your sectored analysis go?

- Remember, we are not talking about a biofuel standard here. It is a low carbon fuel standard and the amount of biofuels that can be blended are limited by federal law, although EPA is looking at changing those percentages. The compliance scenarios are going to have to take into account the amount of blending of biofuels that can happen and also look at the other types of low carbon fuels. For example, electric vehicles and natural gas vehicles and so forth that wouldn’t necessary affect your equipment because you would be using different sectors. And the compliance is at the level of the oil company where they are doing a calculation at the end of the year to show that their credits and deficits add up. So it doesn’t automatically, like a biofuel standard, result in your sector getting more biofuels than you can handle with your legacy equipment. Low carbon fuel standard doesn’t necessarily result in that.

- If you look at how deep those fuel prices are, then you have a different class of business Oregon economy or sector. There are very basic, few key variables that, in fact, use the low carbon fuel standard as an option. And you are looking at the main fuel price that impacts the economy. And at the pump current prices, those kinds of effects will be looked at. So you have indirect to the economy. And that would not be easily captured. Not because of the main fuel price can affect any particular sector in town so the cost of production and cost of distribution would be assessed. That would impact even the state.

- We are a price taker right now, but one of the co-benefits of the low carbon fuel standard is to become a price maker by producing more of a fuel locally, either through biofuels or through electricity. And then also one of the key things that is not in this model and I don’t expect it will be, but I do hope that we’ll talk about it and provide some data, maybe outside of this on some other research that has been done so that way we have some contexts around the environmental social benefits of the program. For example, if we are able to reduce some of the air toxics associated with fuels then we will also be having health benefits in reducing healthcare costs. So that is something that conceivably should be in the model, because out of all the externalities that are able to be captured that is probably the easier data points, lots easier around climate change and things like that. But to the extent that we can, at least, capture that benefit as a descriptor outside of the model would be very helpful. **Response (ODOE): They want quantitative variables. Some of this is a direct impact that we can measure or capture. We have to look at literature and quantitative assessment and bring that into the analysis in terms of the report. It is not doable in REMI.**

- A couple of people have made the point that we need to make sure that we capture the economic benefits of the program as well as the costs, and a key factor really is, what is going to be the future price of crude oil versus what is going to be the price of delivering low carbon fuels. That’s the guts of the analysis and I think that is what REMI is going to do. When you are looking at the 70 sectors and then the other sectors that are not highlighted, if you see ones that we need to highlight, let us know. We’ll make sure that we capture those, but the basic piece of the analysis is really the business as usual case forecasting, what is going to be the price of petroleum fuels, and how much is it going to cost to produce these low carbon fuels. The analysis is going to be probably quite sensitive to the forecast of future price of petroleum. The other question I wanted to ask you is on sensitivity analysis it seems like one of the key factors is going to be looking at the price of crude and are we going to be able to have some sensitivity on that? Like if crude is $100 per barrel, this is how low carbon fuel standard is. Or if it is $50 a barrel,
here is how it is. From what I understand a lot of the benefit is diversifying the fuel supply and having some stability of alternate fuels relative to just the crude oil scenario. **Response (ODOE):** Yes, a typical crude oil forecast will have at least, two to three price breaks scenarios. Finance deals stop working if crude oil prices go below a certain price. So there will be some threshold variables that will be accounted for. We may not have 20 sets of crude oil prices, so there is a range or degree of perfection that need to be forecasted. But there will be some break apparent low, medium, and high case for crude oil price forecasting that will be viewed to, in effect, different economy conditions.

**Summary of written comments from advisory committee member or alternate June 17, 2010**

- Staff should be commended on selection of Jack Faucet and Associates as the economic modeling contractor. They are a well-known, national entity with very well thought of credential and reputation for this specific type of work. In addition, directing the the use of the REMI model will clearly address the interactive dynamics, nuances and market complexity well. The breadth of modeling 70 markets is likewise well advised.

- There are numerous externality benefits we would like to see modeled and valued in the economic analysis such as air quality, community health, potential rotation cropping benefits, etc. etc. At this juncture, they are not addressed by the model scope. Should there be opportunity for the contractor to address some of those additional outcomes it would be refreshing, useful and likely more compelling an economic model for a broader Oregon constituency.

**Summary of written comments from advisory committee member or alternate June 25, 2010 regarding the proposed economic analysis**

- The timeframe for the economic analysis should capture all of the costs and benefits. For example a car purchased in 2015 will continue to have fuel savings impacts beyond the horizon year of the program.

- The economic analysis should consider beneficial impacts on regional economic activity and employment. The commenter cites comments on NESCAUM’s economic analysis “Specifically, the analysis should delineate the following impacts:
  
  - Percent of GSP increase (decrease) resulting from growth (decline) in regional fuel production;
  - Percent of GSP increase (decrease) resulting from lower (higher) fuel prices;
  - Percent of employment increase (decrease) resulting from growth (decline) in regional fuel production and/or the manufacture of vehicles and component parts needed to use low-carbon fuels; and,
Consider the impact on Oregon Greenhouse Gas 2020 Goal - it is important that the value of the CO2 reductions of the LCFS in contributing to Oregon's strategy to meet the 2020 goal be recognized - ie. the cost to meet the goal will be higher if this fuel component is not achieved.

Review the State of Wisconsin LCFS macroeconomic analysis, which models a non-LCFS biofuels policy that impacts the agriculture and forestry sector positively to see if it suggests ways to capture the homegrown jobs of the LCFS substitution factor in OR. (http://www.climatestrategies.us/ewebeditpro/items/O25F22680.pdf)

Account for existing complimentary carbon reduction strategies. The United States and the State of Oregon have several existing strategies that will lessen the burden to meet a 10 percent reduction in greenhouse gas emissions intensity by 2020. For example, renewable fuel standards already incent the development of biofuels. The national and state tailpipe emissions standards will also decrease the hurdle of developing low-emission vehicles, which, although these “Clean Cars” standards will not change the carbon intensity of existing gasoline and diesel fuels, could affect the relative cost accounting for fully electric vehicles. Additionally, for more than 30 years the State of Oregon has incented renewable energy and conservation technologies that can help catalyze the development of alternative fuels.

Recognize the cost of replacement policies to achieve state greenhouse gas reduction goals. In 2007, the Oregon legislature adopted goals to reduce greenhouse gas emissions 10% below 1990 levels by 2020 and 75% below 1990 levels by 2050. One of the key strategies adopted by the 2009 legislature to achieve the 2020 goal was the LCFS. Failure to fully adopt the LCFS will require the adoption of additional climate policies to make up the carbon gap. In addition, failure to meet the 2020 standards will require even deeper cuts later than currently targeted by the state. These necessary additional policies will have a significant cost. Although the purview of this economic study is ostensibly to just account for the gross state product impact and not the externalized costs and benefits of an LCFS to society, it is essential that these impacts be reflected through at least a detailed and thorough literature review. In particular, the following should be considered:

Account for emerging technology and business benefits. Within the economic study, it is important that several factors be considered:

- New businesses and jobs – both direct and indirect – as a result of the development, production, manufacture, distribution, and infrastructure enhancement for new alternative fuels and complementary vehicles.
- Local income and property tax benefits as a result of new business in Oregon.
- Fuel cost savings to Oregonians as a result of lower gasoline and diesel usage and increased overall supply of transportation fuels.
- Grid-balancing using electric vehicles.

Account for the environmental, health, and other social co-benefits. Although the purview of this economic study is ostensibly to just account for the gross state product impact and not the externalized costs and benefits of an LCFS to society, it is essential that these impacts be reflected through at least a detailed and thorough literature review. In particular, the following should be considered:

- Health impacts from decrease air toxins and particular matter.
  - Asthma rates
  - Cardiovascular diseases
- Environmental hazards and costs associated with producing and using fuels
  - Climate change
- Oil spills
- Coastal dead zones
  - Improvement in Oregon’s trade balance from decreased oil imports and becoming less of a fuel price taker and more of a fuel producer.
  - Avoided environmental regulatory costs.
    - Clean Air Act costs, such as ozone compliance.
    - Early action to reduce greenhouse gas emissions will ease the economic transition to a national comprehensive climate policy such as cap and trade or carbon fees.

- Account for administrative efficiencies. With several other states working on LCFSs, Oregon stands to gain significant cost-savings from using the shared knowledge, tools, and experience of other states – especially California.

- Estimate the impact of the 2015 sunset. The LCFS is currently scheduled to sunset in 2015. The economic study correctly will consider the impact of the LCFS as if the 2015 sunset does not exist. However, also of importance is delay of removing the sunset on the market for technological innovation and deployment for alternative fuels and complementary vehicles. The economic study should make a separate market impact assessment of removing the sunset under three scenarios: 2011, 2013, and 2015.

- Account for post-2020 impacts. The upfront incremental cost of alternative fuels and complementary vehicles is likely to be substantial, the long-term fuel savings to the owner is also likely to be substantial but spread out over several years. When making a vehicle purchase, the owner will account for both the upfront costs and the long-term benefit. But an economic analysis that accounts for the costs and benefits of a vehicle to the owner in a given year will exaggerate the costs. A car purchased in 2020 will have substantial costs in 2020 and nearly zero benefit, but those benefits are real and will be accrued in future years. Since the “payback” period on the purchase of a $35,000 plug-in hybrid might range from 7 to 11 years, we suggest that the economic study account for the benefits through at least 2033 (for a 2022 LCFS reduction target).

- Use the 2020 horizon compliance year. The language of the organic legislation for the LCFS plainly makes clear that the state Environmental Quality Commission is authorized to create a schedule to achieve a 10% reduction in the greenhouse gas emissions intensity of fuels by 2020. Given the legislature’s intent to achieve the state 2020 climate goal and the physical carbon constraints mankind now operates must now under, we interpret the 2020 statutory year not as a ceiling for which the Environmental Quality Commission cannot go any earlier, but rather a floor that the Environmental Quality Commission cannot go beyond to fully implement the LCFS. In order to stabilize the Earth’s atmospheric concentration of greenhouse gases at the lowest possible amount will require frontloading reductions as soon as possible. The LCFS legislation was a cornerstone climate policy during the 2009 session to achieve the 2020 state climate goal. Any delay in implementing the LCFS frustrates the state’s ability to meet the state climate goals and will require compensatory climate reduction strategies that will likely be more cost prohibitive. In order to make the case to the public for fully implementing the 10% reduction target by 2020, the economic study must analyze the economic impact of doing so. Given that the legislature authorized the Environmental Quality Commission to implement the 10% reduction target by 2020 and given the physical nature and state goals for carbon constraint that the state now operates under, the economic study should use 2020 as the horizon year, and not any later date.

- Account for transition in LCFS schedule to indirect effect accounting. Environment Oregon believes that indirect effects are a critical component for conducting a lifecycle analysis of transportation fuels. We also recognize that the science is not yet settled and we believe that we should continue to process new information and research and then formally adopt the best available science in 2013. This phase-in of the
indirect effects data will have a small but perceptible impact on the compliance scenarios, which should be accounted for in the economic study.

July 7, 2010 Advisory Committee Meeting

- Two years ago, who knew that oil would peak at a $147 a barrel. Today it was $73 and it has been about $68 to $85 in the last several weeks. Nobody predicted $147 a barrel two years ago, or the plummet down to below $40 a barrel a few short months later. So it really is difficult to predict.
- It seems like part of the advantage of encouraging biofuel production is to give us a little more robust system and not be crippled by volatile fuel prices, and if the benefits of that are not incorporated in the economic analysis, then I think you are missing something.
- If you have a monopoly and you add in some competitors then it gives you some resilience in your economy. right? So, does that come out of the REMI model? And the focus is 10%, which is probably pretty small, but is that considered?
- I think this came up last time, which is that we are essentially a price taker and low carbon fuel standard isn’t likely to change that in a huge degree, although maybe if we huff it after 2020 or 2022, we might become more of a price maker.

Summary of written comments from advisory committee member or alternate July 15, 2010

- Environmental and public health co-benefits. Petroleum-based transportation fuels emit smog-forming compounds and particulate matter that contribute to air pollution linked to asthma and cardiovascular diseases. Oregon residents that live along high traffic and congested roadways suffer disproportionately higher rates of these diseases and tend to be marginalized communities. The health savings associated with reducing petroleum-based fuels should be evaluated and the equity impacts should be considered. Analysis of these benefits have been conducted and verified and those results could easily be indexed to the fuel blend changes forecast in the economic models. Environmental costs that should be considered include: the cost of oil spills to Oregon’s water and land; climate impacts on health, wildlife, and industry; and the benefits of replacing internal combustion engines with electric engines (e.g., the reduction in non-point source pollution, such as oil spilled during oil changes and roadway runoff).
- New and emerging businesses. The low-carbon fuel standard will help create a market for new fuels that will create new businesses related to production, distribution, and refueling. Because many of these businesses do not yet exist, the cost to existing suppliers may look outsized compared to the benefits of these new industries. Estimates of direct and indirect job creation, new tax revenue, and lower fuel costs should be evaluated. Our experience with biofuels employment per gallon of production in Oregon and the need for advanced fuels to meet LCFS targets should be easily considered by the economic model.
- Benefits of reducing oil use. Oregon imports 98 percent of its transportation fuels. The LCFS should reduce demand for oil so improvement in Oregon’s trade balance should be evaluated. Similarly, the benefits of diversifying the transportation fuel pool as a buffer against oil price spikes should be included. Because Oregon policies often set the stage for national action, the larger economic and security benefits of reducing oil use should also be considered. Because oil prices are particularly difficult to predict into the future, the analysis should evaluate a range of oil prices and ideally also include a nonlinear scenario that includes price spikes such as those that occurred in 2008.
- Corollary benefits. Oregon’s adoption of a LCFS puts the state ahead of the curve for potential compliance with federal programs. Historically, Oregon has benefited from such leadership. For example, Oregon was an early adopter of clean car standards at the state level. A federal standard was
recently adopted and Oregon already meets the requirements. Adopting the LCFS could potentially allow Oregon to capture a larger share of the renewable fuels market for in-state producers. Oregon is also part of a larger West Coast green highway initiative. Both California and Washington are working on a LCFS. Oregon’s proximity to these markets gives low-carbon fuel producers an advantage to exporting to these other markets, especially California’s large fuels market.

- The economic analysis should also take into consideration impacts of the 2015 sunset. Emerging businesses need the certainty of longer time horizons to make investments. OEC also supports including analysis for the 2020 horizon in addition to the 2022 timeframe.

**August 10, 2010 Advisory Committee Meeting**

- Does this model map changes in wages and prices for goods that are going to be driven by this increase in construction? *Response (ML): Yes, it does.*

- Will you be writing scenarios where the plant is in Boise, Idaho rather than Oregon? *Response (ML): Yes, but it’s just a matter of whether it’s in Oregon or outside of Oregon.*

- Are you trying to get to a net figure of economic activity statewide, or do you have it be more complicated than that? For example, under some forecast scenarios, I could see consumers in urban areas losing out on a higher gas price, but construction workers in eastern Oregon doing quite well – and on a net basis, very little change. *Response (ML): Geography is built into it, so it can be run for individual states, it can be run for individual counties, you can run it for a metropolitan area. However, we’re not going to take the REMI model down to the county level for this purpose.*

- How does the model deal with technological issues? I’m sure there are a lot of things to work out with existing industries and new industries that emerge. How does one allow for that? *Response (ML): It’s not able to predict; what it does is take a look at the rate of technological change, and it builds the same rate of change into the future.*

- Does this approach capture any of the implications on consumer welfare? *Response (ML): No, it doesn’t.*

- My main comment is that I don't trust nearly any oil price estimates especially EIA's. While not a paranoid doom and gloom peak oil freak, I have read enough - including DOD research, that leads me to believe this won't be a comfy slow transition. I think price shocks will occur. Sadly though, I think folks will casually absorb any increased costs that may be associated with Alberta sourced crude.

- My other comment is that I don't believe a cost of carbon will be felt at the pump. At most we are looking at 20 cents per gallon - which falls well within what people regularly tolerate and may not even notice. Which also leads me to state that LCFS caused price changes will likely go unnoticed by anyone that is currently subject to the dynamism of the market.

**Summary of written comments from advisory committee member or alternate August 24, 2010**

- Any oil price estimates are not trustworthy, especially Energy Information Administration's. I have read enough - including DOD research that leads me to believe this won't be a comfy slow transition. I think price shocks will occur. Sadly though, I think folks will casually absorb any increased costs that may be associated with Alberta sourced crude.

- A cost of carbon will not be felt at the pump. At most we are looking at 20 cents per gallon - which falls well within what people regularly tolerate and may not even notice. Which also leads me to state that
LCFS caused price changes will likely go unnoticed by anyone that is currently subject to the dynamism of the market.

**Summary of written comments from advisory committee member or alternate October 6, 2010**

- I believe that any legislation, regulation, rule, or standard must consider the impact to people and jobs--today's jobs. Many will emphasis the POTENTIAL, but I encourage the DEQ to assess real jobs that currently exist and may be lost by such actions. As such, I'll reply individually to your questions.
- With so many variables, including the current ongoing economic crisis and potential for research and development, I propose adding an economic "barometer." If the unemployment rate, consumer price index, or some other measurable data does not trend positively, I encourage the DEQ to assess its actions before adding to the situation in a negative manner.
- This could lead to job creation but may eliminate current jobs. Oregon is not viewed favorably from a regulatory perspective, and unless we address it, our work to be an innovator in "green activities" may be futile. Too often our intention to make a positive impact has led to requirements which cause unnecessary problems, increased costs, etc. As we consider elements of an Oregon LCFS, let's remember that we must feed people. We cannot work against energy. Look at the existing barriers--inability to draw water from the Columbia, the salmon, etc. As we want to do more, how will the current known barriers be mitigated?
- Should early adopters be punished while laggards are rewarded?
- This is positive if agencies collaborate, specifically the Oregon PUC and DEQ. Where does the Oregon legislature fit in this mix? What about people and jobs? Good, family-wage jobs must not be lost.
- In summary, I hope the Oregon legislature, PUC, and DEQ can collaborate to ensure jobs are not lost, people are not disheartened, and businesses relocated or avoided due to restrictive regulations. I know a lot of resources--time and money--have been invested. Let's make sure that we do not take actions which will be even more costly later.

**October 14, 2010 Advisory Committee Meeting**

- Michael mentioned uncertainty associated with a range of compliance scenarios; can you speak to the confidence intervals of the models used to generate the economic analysis given a swing of global economic conditions? **Response:** (Michael Lawrence, JFA) The difficulty in forecasting lies in predicting the level. It is much easier to predict the change in the level as opposed to the level itself. The process focuses on the change and not the level, and predicts how much the level will be impacted by the compliance scenarios. The scenarios were provided to JFA and are intended to represent a wide range of alternative supply scenarios to meet the standard as designed. The idea being that the range of scenarios would capture the future reality of Oregon’s fuel mix, and if that future fuel mix turned out not to be captured by the compliance scenarios used in the economic analysis, the model may need to be run again. Hopefully we’ll learn as we run the model in terms of the economic impacts how the economy is changed by particular changes in the scenarios, such as changes in fuel price, indirect land use change values, fuels sources, etc.
- Are you only using one baseline assumption in all compliance scenarios? **Response:** (Michael Lawrence, JFA) There is only one business as usual baseline, and all of the eight scenarios are compared against that baseline. There are a number of paired comparisons, such as in scenario F and G, which consider both high and low fuel prices against the baseline, where as scenario C compares the median price to the baseline.
- On the chart titled ‘Biofuels used in Oregon Low Carbon Fuel Standard Compliance Scenarios in 2022’, it looks like there is a high and low oil price in the business as usual case as well. **Response:** (Scott Williams, JFA) With regard to the fuel baselines, JFA ran the high and low fuel price scenarios against the same baseline, but we applied the fuel price modification to both the baseline and the scenario. So the baseline did get an adjustment, but other than that, no changes were made to the baseline or any substantive fuel source or other economic or fuel-based assumptions.

- Will the matrix of assumed fuel prices used in the compliance scenarios be made available to the committee? **Response:** (Michael Lawrence, JFA) Yes. As JFA finishes the review process, we will be preparing a final report which will provide great detail on the entire process from the scenario development through the micro modeling (VISION), conversion of VISION outputs into inputs for the macro modeling (REMI), and analysis of the macro model outputs. The final report with all the associated data will be provided to the committee for review.

- It seems counterintuitive that in scenario E, which is a one-pool scenario, you’d have increased biodiesel and diesel spending. **Response:** (Michael Lawrence, JFA) That is one of the results that prompted me to say that these results are still preliminary. One of the issues with a one-pool scenario is the potential for fuel switching of light duty to diesel consumption. If we go back and look at scenario D, we see a drop in gasoline consumption, and it doesn’t appear that the up bars are sufficient to balance the gasoline drop, so that may be a substitution diesel for gasoline, but still need to go through the data and verify that is indeed what is happening.

- Does the 120+ miles per gallon figure for the energy equivalent to gasoline gallon for electric vehicles on slide 21 of your presentation take into account all the way up to generation, or is it end vehicle use? **Response:** (Scott Williams, JFA) All fuel inputs are full-cycle inputs and they use GTREET to generate an emissions factors that attempts to include all the elements of the process of producing, delivering and transmitting that fuel up until final consumption. The “gallons” in quotes is an energy equivalency drawn from an AEO projection of vehicle efficiency of a light duty vehicle running on electricity as a fuel.

- For clarification, looking at the bar graph for gasoline on slide 19, do the bars below the x-axis mean that relative to the BAU there will be less gasoline expenditures, but the expenditure could still be more than it is today because that’s a change off the baseline? **Response:** (Michael Lawrence, JFA) That is correct. So it doesn’t mean that there is an actual reduction in spending on gasoline, but it’s a reduction relative to the BAU case in the future? **Response:** (Michael Lawrence, JFA) That’s correct.

- The JFA presentation talks about an energy efficiency ratio of four for electric vehicles, and the committee has talked about using an EER of three in prior meetings. Did you use three or four in the economic analysis? **Response:** (Michael Lawrence, JFA) We did not use any, because that comes out of the VISION model run by TIAx, and that was a decision made by DEQ. **Response:** In a previous committee meeting, we discussed using an EER of four and having it decline to three, because today’s electric vehicles are four times more efficient than gasoline powered vehicles but in the future, because of the fuel economy standards for gasoline vehicles, electric vehicles will be three times as efficient. My recollection of that discussion is that we didn’t reach a decision; I thought we settled on three. **Response:** DEQ proposed an EER of three, but the advisory committee had a lot of comments about that. And then in the cost assumptions that TIAx presented, that is what they said. **Response:** (Scott Williams, JFA) I have the model in front of me now, and the EER values used were about a four to one ratio in 2010 and three to one in 2022. **Response:** DEQ needed to adjust the values to account for the fact that California gasoline is reformulated, and Oregon gasoline is not. So the actual values used by TIAx were 4.1 for 2010 declining to 3.1 in 2022.
• I realize this is an economic analysis and not a consumption or emissions analysis, but is it possible to get a chart that shows where the BAU consumption line is going under these compliance scenarios, as well as emissions, so we could see not just what the cost impact is of the scenarios, but also the emissions reductions that would occur under each scenario compared to the business as usual line?  
Response: (Mark Reeve, Chair) The statute includes overall emission reduction, but even on the economics business as usual we need to know if petroleum usage is going up or down and what the usage looks like in 2022. At a minimum, you’d want the inputs for the economic model to be consistent with other findings for consumption trends.  
Response: To clarify, all compliance scenarios are designed to meet the emissions reduction goal of HB2186.

• The baseline is using a proportionate allocation for all states’ RFS2 requirements?  
Response: (Michael Lawrence, JFA) Yes.

• Micro impacts for scenarios A, B, C, D and even D don’t show anything off of baseline until 2017 or so. Anecdotally, it seems like there is already more spending than what the graphs show.  
Response: (Michael Lawrence, JFA) This graph is only showing expenditures for ethanol and biofuels plants (production facilities,) it does not include the infrastructure for electric charging systems.

• Is the big hump on the line graph (slide 43) due to construction of biofuels facilities?  
Response: (Michael Lawrence, JFA) That’s correct. We cut off the analysis at 2022 so we can’t see what’s going on after that, but if we went 40 or 50 years out, we wouldn’t see this much drop, because we’d see pick up of employment at those facilities and new construction as demand changes over time. So that end point at 2022 is not the ongoing operational level?  
Response: (Michael Lawrence, JFA) It is the operational level.

• And are these direct or induced impacts?  
Response: (Michael Lawrence, JFA) These are the macro economic impacts which are the result of the direct impacts, so this is only showing the direct, indirect and induced changes in economic activity that has been provided to the model. The direct impacts are fed to the model, and the model calculates indirect and induced impacts.

• What type of a multiplier does this type of attrition generate?  
Response: (Michael Lawrence, JFA) I don’t have that number off hand, but it’s probably in the two to three range.

• In some of the charts the start year used is 2012, but this chart (macro outputs of employment) begins in 2010. What is our starting point for measuring?  
Response: (Scott Williams, JFA) The sum values are 2012 through 2022. The models start in 2010 because they build each year so they have to start from now, but the analysis period is 2012 to 2022. In theory we could have shown the charts as starting in 2012 because 2010 and 2011 are not part of the analysis period, but when we sum over the period to calculate the total impacts, we’re doing it only for 2012 to 2022.

• Scenario D seems out of whack because that means you’re adding significant additional new jobs each year, rather than creating jobs and keeping those same jobs. This seems to be adding incremental new jobs on top of last year’s incremental new jobs more than it should.  
Response: (Michael Lawrence, JFA) The expansion of the electric infrastructure continues, and that’s why job growth continues under that scenario. At some point you reach a steady state, and then you’d have population growth.

• In terms of the numbers, are those job years, or actual jobs?  
Response: (Michael Lawrence, JFA) Those are job years. It’s the sum of the employment over each of the analysis years.

• There’s something else at work here. Scenario D has three very different economies at work coming up, so it adds to the notion that when you’re looking at infrastructure for some of the alternative fuels you see a multiplier effect adding on to a cumulative effect of three different sectors growing at the same time. So
you have three different kinds of labor economies, three different sets of markets, and three different sets of processes being modeled together as one scenario.

- In this morning’s paper, BP and Arco announced that they will be installing electric charging stations soon, which I assume means before 2012. Does that modify the business as usual case, or is that counted as future growth? **Response:** (Michael Lawrence, JFA) I don’t know the answer off-hand. If we thought there was a reason to change the business as usual case due to some fundamental change in what we believe to be investment strategies unrelated to this rulemaking, then it might be worth looking at the business usual case and whether it should be reconsidered. We’re not creating the business as usual case, we are using the Department of Energy’s forecast and modifying to be Oregon specific, but it is their extrapolation of history and what they expect going forward.

- Is there any thought on what effect the recent increase of the federal blendwall for the ethanol standard might have on the compliance scenarios? **Response:** Six of the eight compliance scenarios modeled include E10 as the blendwall, and Scenarios B and C have and E12 blendwall starting in 2017 which increases to E15 in 2020.

- Does the analysis include the infrastructure investment needed for blender pumps? **Response:** TIAX did include additional infrastructure costs for ethanol for some of the scenarios, but I’m not sure exactly what those costs were.

**Andy Ginsburg:** Under scenario H, if we’re assuming out of state production of ethanol to meet the requirements of the LCFS, Oregon will already be receiving its proportionate share of ethanol to meet the requirements of the RFS2, and in order for the comparison to be apples to apples we probably need to adjust the business as usual case to reduce the in state production. I’m wondering if we are creating an artificial effect in terms of the net, if we’re just looking at the net difference from business as usual. It’s something to think about when analyzing the data to make the comparisons apples to apples, the same way changing the fuel prices does. **Response:** (Michael Lawrence, JFA) That adjustment would eliminate the negative bars. **Response:** (Mark Reeve, Chair) It’s an important point and something to think about and work through, not for immediate resolution, but as something to think about.

- Are we assuming that Oregon is the only state that adopts a LCFS in this analysis? **Response:** (Michael Lawrence, JFA) We’re not making that assumption at all. We’re indifferent in this analysis to what happens with low carbon fuels standards outside of Oregon. We are making assumptions that alternative fuels are available to meet these requirements or inputs available to meet requirements of plants that might be constructed. Where the plants are built depends on where the fuel is needed due to transportation issues, and if Oregon were the only state to adopt a LCFS, under that scenario, the incentive to build plants to supply that fuel is in or close to Oregon. But if it becomes a national standard, or regional standard, then the incentive to build plants gets focused largely on areas with high populations. It is unclear why the business as usual scenario changes at all, assuming there will be broader adoption of the standard throughout the nation. **Response:** (Michael Lawrence, JFA) There is already a substantial amount of ethanol produced nationwide, and the assumption imbedded in these scenarios is that there is an opportunity to produce fuel in Oregon, and DEQ has made an analysis of the various fuels supply options, and the compliance scenarios break down where those fuels would come from. If the fuel indeed comes from those modeled sources, there will be required capital investment to gather the feedstock, process the product and distribute to the market place, and those capital investments and associated employment are the positive economic impacts associated with these rules, assuming that the scenarios accurately reflect what occurs in the future. If you continue to ship dollars out of state for ethanol just as you do for petroleum, there will be no positive economic impacts from the standard. The positive economic impacts come from the change in the overall economic structure in Oregon so that Oregon becomes a fuel producer and not just an importer. **Response:** DEQ will make
available the table that will show where the fuels are assumed to come from and in what volumes once we’ve double checked the data.

- The baseline in REMI has input on the projections where if you go farther down, you have some sectors that are changing constantly, and in neighboring economies, as in neighboring regions, you are seeing state management or voluntary efforts to explore low carbon fuel options or infrastructure. And that is impacting the cost, quantity availability, and even technical know-how, which is something we need in Oregon. And that is influencing to some degree the ease and degree of which low carbon fuels could perhaps be easily explored, or explored at what cost, given that we are cost takers.

- If we’re looking at Oregon in isolation, have we calculated in an avoidance factor? Given our aversion to biodiesel at the moment, and if there is a price differential, then there should be an avoidance factor for both rail and trucking, because we are capable of buying fuel elsewhere. Response: (Michael Lawrence, JFA) We can think about that in the change – remember what we provide to the model is dollar expenditures for fuel and if we were to reduce that by some portion we’d have less impact. That could be done but the fuel taxes would still have to be paid to Oregon since you pay taxes on where you drive. Oregon doesn’t have a fuel tax. Response: (Michael Lawrence, JFA) The weight-mile tax applies.

- Michael mentioned the only benefits in this analysis are due to the plant construction in-state. With the scenarios being discussed, would this avoidance factor then eliminate that positive impact and add a negative to it? Response: (Mark Reeve, Chair) I thought I heard Michael say that it would be an overall reduction of fuel use potentially, and if truckers that fuel their trucks in Washington drive through Oregon and re-fuel in California, what percentage of fuel use in Oregon it could represent. And that percentage reduction of fuel use would come off the overall gains and losses running through the model, so unless you have a huge plant that is anticipated to be built doesn’t get built, I’d think you would bring down those benefits proportionately. Response: (Michael Lawrence, JFA) I’d have to think about it a little more, but I can’t think of any other. You have to pay fuel taxes in Washington and weight mile tax in Oregon, so that would make it less desirable to try to avoid re-fueling in Oregon. That’s not correct, the tax system is based on where the fuel is burned, not where it’s purchased, so you’re going to pay the same amount of tax no matter what state you’re in. So tax is not a motivator. Response: (Michael Lawrence, JFA) In terms of location of fuel purchase. Correct. While I agree with you that the total amount of fuel we’re talking about is small because gasoline is consumed in much larger quantities than is diesel in Oregon, but it is a significant portion of the diesel consumed. Response: I think it’s an effect they could explore, maybe as a sensitivity analysis of “x” amount of fuel is able to be purchased out of state. You’re missing the point, because at one point we said we’re looking only at Oregon, and now we’re looking at effects of a LCFS regionally. Response: No, I’m not looking at it regionally, I’m questioning whether your scenario of avoidance is realistic when you consider that California already has a standard, Washington is considering a standard, and our indication is that the price isn’t going to be different and so you have a scenario that we could look at sensitivity on to see if it makes a difference. Based on what you’re saying the investment scenario needs to reflect that there is going to be demand for low carbon fuels in Washington and California too because of their standards, which would impact the location of plants.

- We can’t assume that all these biofuels plants will be built in Oregon because California and potentially Washington also have a LCFS, and plants will likely be built in locations with large populations. Response: There isn’t an assumption that all these plants will be built in Oregon. If you look at all the scenarios, there are some in Oregon, some in the northwest and Midwest.

- If there is avoidance in diesel, the likely outcome is that you shift to a different scenario, because you have to comply with the standard based on the fuel burned in the state. In all scenarios except for H, the benefit was there so the impact is still positive. Response: If we have two pools, whereby gasoline and
diesel are treated separately, I don’t think gasoline is affected by what happens in diesel. But if the effect of the diesel scenario is that less fuel is sold in Oregon, they would still have to meet the standard for the fuel that is sold in Oregon so you’d still get the ten percent reduction but there would be less total fuel sold. So we’d still get the same environmental outcome for our state, but that would be a negative effect for the Oregon economy. It would be similar if you reduced vehicle miles traveled in any sector, it’s just less fuel sold in Oregon.

- This raises the question of how we’re accounting for compliance. We discussed using the weight-mile tax as the numbers we’d use for the net amount of fuel used in the state, and if we’re using that number to hold accountable the system, then we would have to figure out how that would work.

- My understanding is that the statute indicates fuel sold in Oregon, not used. **Response:** (Mark Reeve, Chair) Under a one-pool scenario, if diesel is part of the one-pool scenario, I think there would need to be a shift to some other biofuels.

- This doesn’t seem to look at some of the roll-out impacts of the compliance scenarios. For instance, in the high electric scenario, it doesn’t show any negative losses as a result of that scenario being implemented. For example, if you have more investment going into electric vehicles and more people driving electric vehicles then you’re going to have a reduction in conventional petroleum and or ethanol blended fuels consumption. And as a result of that, you’re going to see a reduced need for stations and associate job losses, and this doesn’t show those job losses, does it? It only shows the positive? **Response:** (Michael Lawrence, JFA) No, it shows both the positive and the negative. The macro-model is provided information on the change in individual sectors. For example, in the purchase of petroleum products either by households or by industry, the model is provided that change so there is a reduction in all cases. In the graph with the change in fuels and the high and low bars (slides 19 & 20), that’s a reduction of activity in the petroleum sector and that information is provided to the macro model to run the change so it includes the reduction in output from the petroleum sector and all of the inputs that might be required for petroleum. So it includes the petroleum distribution system, less transportation purchase, less fuel distribution infrastructure. The macro model is a very aggregated in its process, so it is looking at the change in dollars and is not focused as much on the specific subcomponents of production and distribution of the product. It would not tell us, for example, that instead of having X number of fueling stations we’ll only have Y number of stations. What it does tell us is that the output of the petroleum sector is reduced and that reduction in output reduces GDP, reduces employment, and it reduces personal income by amounts that are associated with a particular industry.

- Does the graph on slide 36 reflect the job losses associated with the decline in the demand for fuel? **Response:** (Michael Lawrence, JFA) That’s correct, in the reduction of output from the petroleum sector. **Response:** This is the net effect, and in the more detailed report that JFA will make available to us we will be able to see what occurs more specifically by sector what goes up and what goes down. **Response:** (Michael Lawrence, JFA) Correct. The REMI model produces a wide variety of statistics and information on all of the sectors that are included, and all of the macro-economic variables that are being measured. So you can envision a large matrix of data 70 sectors by all of the macro-economic changes. A full set of materials for all of the REMI runs will be included as an appendix to the JFA economic analysis report so anyone can take a look at the details for each sector and industry to see what is changing.

- Scenario B is the mixed biofuels, so it could be that the petroleum distribution sector might gain more employment because you’d be using that infrastructure.

- Since this is focusing only on Oregon to date, the whole intent of the LCFS is to reduce the use of petroleum, which is going to have a significant impact to the petroleum industry out of state, i.e.
Washington and Utah refineries. If you get to the point where a refinery shuts down, then you’re losing all that economic benefit in Washington but you’re not addressing that loss here, and that would be a significant loss. So we need to make sure that somehow we capture that, because those losses won’t be captured in this economic analysis. **Response:** (Mark Reeve, Chair) I agree, that out-of-state impacts are not being looked at here, and I want to clarify in terms of the intent to reduce petroleum use. I think the intent of LCFS is to reduce the carbon content of the fuel and if those refineries can be used for the production of lower carbon fuels including some of the diesel products being discussed, some of the refineries may or may not see some of those gains or losses. You also have increase in demand in the business as usual model, and petroleum doesn’t go away completely.

- Petroleum is going to be a significant contributor for the next several decades, just like coal and natural gas will be, even though we’ll have significant increases in biofuels as we go forward, but those negative impacts are still there and are not being addressed in this analysis. **Response:** To that point, Washington is doing an economic analysis on a LCFS as well so we’ll have that information, and we could potentially look at both ours and Washington’s reports. These scenarios are being compared to the business as usual case, and we’re not necessarily talking about reducing petroleum which we may have to do with the rate of growth. To get to the point where one of these refineries doesn’t have enough demand because of a change in Oregon’s consumption pattern due to the LCFS is unlikely because we’re not that big a proportion of Washington’s overall market. But the point is well taken that we should include Washington’s analysis. I want to comment on the title of slide 35 – Scenario B is not 100% in-state, it’s mixed and so we’re talking about a mixed in-state/out-of-state scenario with a pure out of state scenario. **Response:** (Michael Lawrence, JFA) Understood.

- The gross economic product slide was for cumulative benefits from 2012 to 2022, is employment also being shown as cumulative jobs and not jobs per year? **Response:** (Michael Lawrence, JFA) That is correct, it is job years as opposed to jobs.

- Will we see a slide with a graph of fuel price assumptions that were made in the analysis? **Response:** (Michael Lawrence, JFA) I have charts of fuel prices from DOE numbers. Or any assumptions used for conventional ethanol, cellulosic ethanol, renewable diesel prices? **Response:** (Michael Lawrence, JFA) I’m not sure I have charts for all of them, but I can get those for you.

- What is the differential between the state product and personal income, what’s the driver? **Response:** (Michael Lawrence, JFA) Gross state product is the sum of what is called value-added in economics and value-added is primarily employment, but it also includes other components of state product such as profit or other incidental charges that get included in value-added, usually associated with employment or business activity. They are not inputs to production; they are not the purchase of raw material or component parts. So personal income is not a component of employment? **Response:** (Michael Lawrence, JFA) Personal income is a large part of value-added because value-added is primarily employment. It is that payment to employment that gets translated into personal income.

- Is the difference in projected plant construction between scenarios B and C due to increased importation of sugarcane ethanol or other imports? **Response:** (Michael Lawrence, JFA) It is a result of increased importation, so less production would occur in-state. **Response:** So if we understand this right, indirect land use change (ILUC) might still be very important in terms of an individual producer’s carbon intensity and how that translates into their compliance obligation, but the effect on the overall economic picture of the program, it doesn’t seem to be a huge driver. **Response:** (Michael Lawrence, JFA) It doesn’t have an impact on the macro model. Did you use the California ILUC values in the analysis? **Response:** (Michael Lawrence, JFA) Yes. **Response:** (DC) The California ILUC values were the highest ILUC numbers currently in use, and they were used in the analysis as an upper bound. **Response:** (AG) Seeing that the scenarios are all relatively close together on the graph (LCFS Economic Impact – Gross
State Product, slide 43), we could say that ILUC or no ILUC doesn’t really have an effect on the economics of the program, and the committee’s recommendation should be based on other factors like uncertainty in the data or things like that. Last meeting we talked about waiting for a while until there is more certainty about which ILUC numbers to use and incorporating them at that point, and this seems to say if we did include it, it wouldn’t really change the economics of the program. Is that fair to say? **Response:** (Michael Lawrence, JFA) That’s fair. Well stated.

- Are the assumptions for the high and low price oil scenarios in 2010 dollars? **Response:** (Michael Lawrence, JFA) They’re constant dollars, and I believe that are 2008 dollars.

- Is that wholesale without tax? Or what is the normal standard? **Response:** (Scott Williams, JFA) I think that’s a full retail price, inclusive of taxes but I’m fairly sure it’s a national average with an adjustment for the Pacific region. It’s a rounded number – I didn’t put the actual figure down to the pennies.

- Are we going to share with Washington the demands for petroleum in our scenarios to inform their economic analysis and in-state employment? **Response:** I think they are already well into their process. Did their analysis take into account any reduced demand for petroleum from Oregon as a result of our LCFS? **Response:** (Frank Holmes, WSPA) REMI generated a normal sector.

- For scenario F versus scenario G, is the picture that the higher the price of gas and diesel the better the LCFS does? **Response:** (Michael Lawrence, JFA) Higher price is resulting in higher economic impact for the state. So if gasoline prices go up to five dollars per gallon then the LCFS provides more economic benefits to the state than if gas were two dollars per gallon? **Response:** (Michael Lawrence, JFA) Relative to the baseline, yes, and that makes construction of the alternative supply more valuable to the state.

- Does this take into effect the demand response for the price? **Response:** (Michael Lawrence, JFA) It does. The VISION model includes demand elasticities associated with price for the products, so when VISION determines the vehicle mixes in the future and what consumption of fuel occurs by each technology, it takes into account the elasticity of the price of that fuel, so when price goes up the consumption will be reduced.

- One of the questions that is still unresolved is whether two use a one-pool or two-pool approach when looking at gas and diesel. What would be the best (two-pool) scenario to compare to scenario E? **Response:** (Michael Lawrence, JFA) It’s in the group with A, B, C, E. Is that similar to the indirect land use piece where that decision would be made based on other considerations and is not driven so much by the economics? **Response:** (Michael Lawrence, JFA) We don’t see a lot of variation as a result.

- Does the gross state production capture state trade balance questions? **Response:** (Michael Lawrence, JFA) Yes, it does.

- Is there a part of the analysis that looks at the impact of possible future legislative activities around the federal carbon initiatives or taxation of carbon or carbon emissions? **Response:** (Michael Lawrence, JFA) It could have been if we designed it that way, but there is no consideration given here for any legislation that might change fundamentally the transportation sector of the energy sector. If you look at the historic business as usual, there is none.

- We had asked for a qualitative assessment of what a 2020 horizon year would look like. Has any qualitative assessment been made using the horizon year of 2020? **Response:** (Michael Lawrence, JFA) We have not looked specifically at moving the end year from 2022 to 2020. If the requirement was to complete the introduction of fuels to be available by 2020 there would probably be higher costs. One of the costs of constructing a plant is the lead time, so if you shortened lead times you tend to increase the cost of production. In terms of the actual impact of those investments, whenever they occur they produce these economic benefits. **Response:** It seems like we could maybe have a couple paragraphs talking
about how using a horizon year of 2020 would result in capital investment earlier which would be a benefit, but it could raise the costs due to less lead time for construction of new plants. I think there are other factors that could affect the VISION runs because you may have trouble getting to the needed biofuels volumes which might make some of the compliance scenarios less feasible or practical. There could be administratively as well, and I think we could describe the impacts qualitatively and what would tend to move it in the positive direction, and what would tend to move it in a negative direction.

- Could there also be a brief discussion in the report on what the kind of value money would have? Because when the horizon year changes, that becomes a point of question. Not just a year by year value, but the value of the program today or better yet, in the horizon year? Response: (Michael Lawrence, JFA) Sure. The sooner you get the benefits, the more the value.

- What was driving the investment dates? Was it when we thought the technology would be ready, or was it pushed out? Because to me they looked a little bit late. Like plant construction doesn’t begin until 2017: was that because the horizon year was pushed out to 2022? What are the variable that were influencing that? Response: (Michael Lawrence, JFA) It’s one to two years ahead of consumption. So the plant is put in place at a time when anticipated demand for the product will occur when the plant goes online. Response: There’s another factor there too which is, construction that will be happening earlier is driven by the RFS2 requirements so it’s not differential from the base case to the scenario cases. So you don’t see that showing up in this analysis, even though it’s happening.

- The WCI effort using the energy 2020 model has accounted for a potential cap and trade scenario, one which is low carbon fuels, what’s called complementary policy. And that data accounts for potential different levels with VMT changes and vehicle efficiency and a low carbon fuels option. So there is some of that information available on the WCI website there is some recent information that accounts for at a more regional level the trade effects and effects of a local LCFS coming up.

- For the scenarios that use the high and low price scenarios based off of gasoline prices, did you take the baseline or average of the projected ethanol price as a comparison? Because I would think there could be quite a difference if there was a high gas and a low ethanol versus a low gas, high ethanol. Those would affect each other. Response: (Scott Williams, JFA) I believe the ethanol prices did change along with the AEO projections. It appears that ethanol does have a greater price advantage against gasoline in the high price scenario even though it does change, it rises a bit less and it has a better price ratio against gas in the high scenario than the low scenario. Is that on an energy content, or a gallon content basis? Response: (Scott Williams, JFA) It’s a price per BTU, price per gas gallon equivalent energy content. Although the difference in the ratios would change in the same way, however we measured it. Slides 51 and 52 are the last five years of AEO price projections of the baseline. The difference between high and low would be shown on slides 53 and 54.

- Regarding the blend wall, if starting next year every car sold into Oregon was FFV (flex fuel vehicle) compatible, the scenarios that are laid out could change drastically, and would allow much more flexibility in the compliance of the LCFS. I want to raise that because as we develop the LCFS, we can’t ignore the vehicle component, and it is a policy position well within the framework of the LCFS. Response: (Mark Reeve, Chair) For clarification, that would lead to higher biofuels consumption. Potentially, it would allow the flexibility for that to happen in terms of compliance scenarios. It’s not mandating anything, but having cars that can run on any level of biofuels, which is one way to address the blendwall issue. Response: (Mark Reeve, Chair) From an economics standpoint, having a higher biofuels capability to some extent drives more instate benefit to the extent that there is more demand for capital expenditures. If you include E85 as creating higher infrastructure costs, that would increase economic activity with infrastructure development. Are there some expenditures already built into the
baseline, in terms of E85 infrastructure? **Response:** (Michael Lawrence, JFA) I'm not sure.  
**Response:** (Scott Williams, JFA) Infrastructure meaning additional ethanol fueling stations? Yes.

- It’s not necessarily E85 we’re talking about in this type of situation. If all new gasoline powered cars were FFE compatible like they are in Brazil, which costs about $50 per car at the most, and then you’re not just talking about E85, you’re talking about whatever the consumer wants, based upon the economics. And you’re not just talking about blender pumps, and it may be that 30% biofuels is what is most economic for the consumer on a given day. So it’s total consumer driven/price driven compliance. I’d like the committee to think about, as we move forward, should there be a vehicle component.

- Are you suggesting that by rule DEQ could have an influence on that? **Response:** (Committee member) Yes, I am suggesting that. **Response:** That is beyond the scope of this committee’s task. I don’t think it should be, because this is the fatal flaw in the California program. They’ve gone ahead and implemented a LCFS program based on a compliance scenario of 30% biofuels market penetration and there’s no way to get there. Do we want to go down the road of having a LCFS and now way of getting there?  
**Response:** In all of these scenarios, we can meet the LCFS greenhouse gas reduction goal with E85 and the gradually increasing blendwall. These are all realistic scenarios, and the reason we are doing scenarios is to bound reality. If the reality that you are hoping for comes true, it will fall somewhere in the range of those scenarios. We’re not precluding it or requiring it, we’re just trying to balance it in the analysis. Unless you think we’ve missed some scenario and another bound is needed to capture that, I think it’s somewhere in between the high and low ethanol scenarios. **Question:** But you aren’t precluding by rule requiring any change to vehicles? **Response:** As part of this rulemaking, we aren’t going to have any vehicle regulations if that’s what you’re asking. That is exactly what I’m asking. The place where it seems like it matters the most is in the assumptions for vehicle fleet. That’s where we have control over the input assumptions.

- **Response:** To be clear on the bounding, with the exception of two scenarios, the compliance scenarios include keeping the 10% blendwall because that was the reality when we put the compliance scenarios together, and scenarios B and C assume the ramp up to 15%, so that’s where you get the upper bound. Washington’s analysis has a 15% blendwall, so we can look at their analysis also to get a sense of the variability and the effects on the program.

- (Paul Bernstein, Charles River Associates on the phone) Do all of the scenarios assume the same level of VMT? **Response:** (Michael Lawrence, JFA) VMT changes by scenario within the VISION Model runs. The VMT is sensitive to the price of fuels then? **Response:** (Michael Lawrence, JFA) Correct. Do you have any information on how the VMT changes across the scenarios and what the prices of the fuels are both individually and the weighted average fuel cost? **Response:** (Michael Lawrence, JFA) We have the fuel prices and the VMT numbers in the VISION runs, but not in a slide or table to hand out today, but we can certainly provide them.

- (Paul Bernstein, Charles River Associates on the phone) Regarding the discussion about bounding the scenarios, isn’t it possible that you won’t have the level of biofuels needed to meet the LCFS? I say this based on the difficulty that is occurring with meeting the RFS2 and the fact that the EPA has delayed some of those requirements. **Response:** We tried to construct scenarios based on realistic assumptions about what could happen, and had a number of committee discussions in putting those scenarios together. It’s possible that those scenarios could be wrong, but we are building into the program several types of deferrals that would account for situations wherein the standard was not achievable. So we will handle that type of situation, should it arise, through implementation, and in the analysis it’s better to assume that we are able to achieve it so we can compare the scenarios. If we can’t achieve it, the program won’t achieve as much emissions reduction as otherwise possible, but there won’t be a significant economic effect because we would either reduce the stringency or defer the requirements.
(Paul Bernstein, Charles River Associates on the phone) For Scenario D (high PHEV Penetration), I’m trying to understand the impact on personal income. If I’m looking at the TIAX assumption correctly on vehicle cost, it seems that the price of electric and PHEVs is a fair bit more expensive than conventional vehicles. Is that true? **Response:** (Scott Williams, JFA) That is true. There is an assumption that there is a significant price premium. Okay, so if that is the case, it isn’t clear where people are getting a boost in personal income. If anything it seems that people will have to pay more for transportation and have less money for other things, and so less money then goes into the Oregon economy. **Response:** We looked into that when we adopted California’s low emission vehicle standard, and the analysis came out that when you consider the extra cost of the vehicles, it’s way more than offset by the fuel savings, so if you finance your vehicle, the monthly payment is less than your savings in fuel costs, so that there is a net benefit to personal income from EV ownership. It does take into account the timing and financing of it, but it is a net positive.

Following up on last week’s discussion about the effect of a sunset on the program, this seems to indicate that the economic benefits are eliminated if the sunset occurs. **Response:** I’d like to hear what Michael has to say about this, but we’ve got a pretty long lag time in new biofuels facilities above the business as usual case in Oregon, and for the long lead times we are assuming that people can plan ahead, but if with the sunset there is enough uncertainty that people aren’t able to plan ahead, the net effect might be that it does raise the cost of those plants because you can’t start planning until 2015 or so until the legislature addresses the sunset. That uncertainty may make it more difficult to achieve those benefits. You’d have to make an assumption about how and when the legislature would address it.

What this lays out very clearly is that because the benefits come later in the program, it is essential that the sunset be lifted. **Response:** Just to be clear, we won’t ask the committee to give us a recommendation on this because we won’t be able to come to an agreement on that point, but hopefully our final report will identify the effects.

We keep referring to TIAX data, and the only information I have form TIAX is dated August 9th. **Response:** Those are the cost assumptions. But it doesn’t have any cost assumptions for the incremental cost of fuel for each vehicle. **Response:** I can get that to you.

Could we also get the fuel prices and carbon emission coefficients in time to review and provide comment on that as well? **Response:** Will the TIAX results be included as an appendix to the report for people to see as inputs to REMI? **Response:** (Michael Lawrence, JFA) All of the process at each step will be documented in our report. They are not available on the website today, but will be included in the report. If we need to have comments back to DEQ by next Thursday, we would need to see that data as well. **Response:** There are several rounds of comments. Right now we’d like to capture your thoughts and questions that Michael can be thinking about while he finishes the economic analysis report. When that report comes out that includes the data used to run the models, there will be another opportunity for the committee to provide input to DEQ at that point as well. But for example if we feel there are other scenarios that are necessary to bound the analysis, we don’t have the numbers to make such a recommendation. **Response:** At this point it is too late to add scenarios. What we’re looking for is input based on the presentation you’ve seen today, what other comparisons we should see, what questions do you have about how the analysis was done so that we can utilize that in finalizing the economic analysis report. When you get the final report you’ll have another chance to comment on the report itself, but it would be helpful to have an interim round of comments at this point. Looking at the results we saw today, which are the first time anybody has seen those results, it starts questioning some of the results of the scenarios because they are so closely bound. If you look at the charts for all these results, except for the total electric vehicle case, they’re all really close together, and I don’t know whether we’ve truly addressed the bounds or not. They all seem to be clustered, and until we look at the numbers in detail
and the assumptions that went into the number calculations, you’re not going to know that. And you can’t do that review until you get the final report done, and then we won’t have any influence as a committee or as a commenter to make any changes. **Response:** So maybe what you’re asking right now is that there be some analysis of the sensitivity of the model to the different scenarios and some explanation in the report about why it’s not sensitive to the elements that varied in the analysis. I think that would be good to have some explanation in the report about that because some of it is counterintuitive to non-economists. Maybe another part of your questions is whether we missed some other variables that might be sensitive too, and I don’t know how Michael would address that. Are there other things that Washington varied that we didn’t that we could look at and see if there was any sensitivity to those? I’m just concerned that we’re not economic experts, so we need to have this available. This is a very significant rule concept that this committee and DEQ are proposing to take on, and if we don’t have a complete, true understanding of what’s going into this, then I’m not real comfortable with it. WSPA will be looking at it, but if we can’t see the data until after the analysis is complete, then that’s a problem. **Response:** Rest assured that you’ll get a chance to look at it before its final. We don’t have it right now, what we have is a preview. If there is some detailed information responding to committee questions raised today we will get you what information we can and then otherwise for now ask questions that will help them write a better draft report, and then when you see the draft report you’ll get to comment on that.

- What we’ve learned from what we’ve seen is that the key variables that we’ve asked to be adjusted in the economic model don’t have a great deal of variance across the spectrum of sources for fuel. I think we can ask to disclose additional variables or invite argument about what fuel prices to use, but it’s not going to change the outcome.

- We may need to have more time than next Thursday to comment on the draft economic analysis.

- Is the review deadline next Thursday driven by our schedule? **Response:** We need to get comments to Michael so he can write the report. We want to do this right, not in a hurry, and we need more than one week to review something this complex. **Response:** I think what you want is more time to review the draft report when you have it in front of you with all the appendices and the data, rather than a summary presentation based on draft results. I’m asking for the data to be available before we give the first round of comments so if we have to make changes to the analysis or the runs that can be done before the final draft is prepared. **Response:** We’d like any initial comments or questions about what you’ve seen today right away so we’re aware of them and can address them in the report. Once Michael is finished QA-ing all the data and assembling it, we’d like you to comment on the full report. Like I’ve said at numerous other meetings, hopefully the people sitting around this table aren’t just representing themselves and in order to get this out to the constituents that we represent, we need time to gather the data, the data has to be available, we have to get it distributed to our constituents, we have to get consensus positions from those constituents, and to expect that in five working days is unrealistic. **Response:** That’s not what we’re saying. That is what you are saying. **Response:** We’re asking only for comments on what you’ve seen so far. We’re having a semantic disagreement right now. You will get a chance to see the full data inputs and outputs with enough time for full review and comment; we just need some feedback today to get the draft report out to you.

- (On the Phone) Regarding availability of data, can you give me an estimate of the timeline to get the tables for the vehicle cost data, the fuel cost data, and the carbon emission coefficients that were assumed? Is that something that can be made available before next Thursday, or should we assume that we won’t be able to have that data available for this round of comments? **Response:** We should be able to get that fairly quickly. If there is a specific piece of information that you’d like to see, we can get that fairly quickly. To make the entire body of work available will take a little longer because it still has to go
through QA, but it will be available for final comment. The TIAX inputs are far enough along that they could be posted for review, and that’s what a lot of people are asking for. The outputs from the REMI model have not yet been QA’d, and we won’t be releasing those tables until there has been time to review that, but I think the inputs are available now, correct? **Response:** (Michael Lawrence, JFA) That is correct, the dollar amount of fuel consumption by fuel type by scenario is the fuel price multiplied by the gallons consumed, and that’s an output from the VISION model, and that can be provided in table form very easily. **Response:** The initial preliminary TIAX inputs are available now on the DEQ website, and we need to update them with the final inputs, which should be easy to do because we took input from committee members. We’ll do our best to get the outputs from REMI posted on the DEQ website as quickly as possible. **Response:** (Marc Reeve, Chair) There’s always a balance between having enough time to review and getting to a completion point and moving on to the next stage. I will do my best to try and strike a balance that is as fair as possible to all the committee members. I voice support for having more time to review the final report and all the associated data rather than shorten that timeframe by lengthening this timeframe.

**Summary of written comments from advisory committee member or alternate October 21, 2010 regarding the economic analysis**

- Disappointed at the extremely short amount of time allowed by the Department to review the LCFS economic impacts analysis inputs and assumptions.
- The amount of time provided and the amount of detailed information provided on the contractors analysis, has been woefully inadequate.
- There are a large number of issues and unanswered questions regarding the information provided by the state's contractors.
- Consistent disregard by the Department of possible additional program impacts, such as program implementation costs, both in terms of substantial DEQ staffing requirements as well as regulated parties administrative costs and individual operators infrastructure burden.

The Charles River Associates report is included here in its entirety.

**Critique of Oregon's LCFS**

Paul Bernstein, W. David Montgomery, Sugandha Tuladhar, Mei Yuan, and Bob Baron

Charles River Associates

Charles River Associates was retained by WSPA to perform a critical review of the scenarios and analysis performed by Oregon's DEQ's consultants in their economic analysis of a Low Carbon Fuel Standard for the Oregon. All opinions, analyses and conclusions contained herein are the authors'.

We appreciate the opportunity to comment on Oregon's economic analysis of its proposed low carbon fuel standard (LCFS). The modeling team in Charles River Associates' Climate and Sustainability Practice has had extensive experience in building and using energy-economy models for the analysis of climate policies, including several recent studies of Low Carbon Fuel Standards (LCFS).

- As part of a study for National Mining Association of the Lieberman-Warner Bill (S.2191), CRA analyzed a nationwide LCFS proposal to reduce emissions by 10% by the year 2020.
- As part of a study on AB 32 requested by California ARB, CRA assessed the cost of California's LCFS program and compared costs under different assumptions about the availability and costs of alternative transportation fuels (http://www.crai.com/uploadedFiles/analysis-of-ab32-scoping-plan.pdf).
- Most recently, CRA submitted comments on NESCAUM's proposed LCFS study.
The state of Oregon faces many of the same issues and challenges that we did in our studies and that NESCAUM does. The many basic uncertainties about new fuels technology and life cycle analysis of emissions compelled CRA to develop high and low cost scenarios. CRA, though, was able to use a single, integrated energy-economic model, but Oregon must also cope with the added complexity of having to reconcile a transportation sector model with a separate, and not necessarily consistent, regional economic model. Our comments, therefore, are based on actual experience in conducting comparable studies. The major points of our review are:

- The modeling approach is critically flawed. Because VISION and REMI models are not internally consistent, as a result the models’ reported economic impacts of the LCFS are erroneous and misleading;
  - Model results must be incorrect in showing an economic gain, to the extent that outcome arises from a reference case in which motorists and fuel producers are characterized as acting irrationally and sub-optimally.
  - Model methodology accounts for investment decisions incorrectly.
- The scenarios do not incorporate a wide enough range of uncertainty;
  - The scenarios assume many of the key conclusions, rather than allowing the analysis to determine them;
  - The scenarios fail to reflect large uncertainties in key variables, based upon prior LCFS analyses conducted by CRA. For example the cost and availability of cellulosic ethanol is quite speculative at this point; therefore sensitivity analysis should be performed to reflect this large uncertainty;
  - Policy off-ramps would reduce the possible negative impacts of the LCFS policy, but they would not eliminate them. There would still be sunk costs, such as those incurred with long-term contracts for Brazilian ethanol, from activities undertaken to comply with the LCFS program.
- The analysis ignores the significant costs of implementing an LCFS in the construction of their reference cases;
- Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol facilities will be constructed;
- Incorrect economic indicators of economic wellbeing are used. Gross State Product (GSP) can be a misleading indicator of overall well being of state residents, as can employment changes and consumer expenditures.

Because of the limited amount of time allocated to us to review the economic assumptions and results of the economic analysis, we have identified a number of issues which we have not had sufficient time to thoroughly investigate. As a result, we have included some questions at the end that voice our concerns about how the analysis was conducted.

### Flaws with Modeling Approach

The modeling approach used that combines the VISION and REMI models is fundamentally flawed. The VISION model fails to optimize consumer choices and, therefore, modelers determine the vehicle choices in the baseline and the scenarios. If the modelers are not careful, they can add a policy that allows consumers' fewer choices but then appears to make consumers better off than they were in the unconstrained baseline. This appears to be the situation in the state's analysis: when the modelers apply the LCFS policy, they find economic gains in all scenarios except one.

This modeling structure suffers from the additional problem that the REMI model fails to capture losses in consumer welfare and account for the full impact of investment decisions. For example if a policy leads to higher delivery costs for goods and services because the policy brings about an increase in the price for truck fuel, then this will translate into higher prices for goods and services so consumers will be unable to purchase the amount of goods they could have in the absence of the policy. This lower level of consumption is a true loss in consumers' wellbeing. That is, consumers no longer achieve the level of consumption that they would have had without the policy. The REMI model fails to capture this economic loss and therefore the results are biased upward. Scenarios A through G report positive economic impacts because investment comes into Oregon from outside the state, but there is no discussion or justification why firms would choose to invest in Oregon rather than produce fuels where it is most economic to do so. In fact if recent investment patterns are any predictor of future investment decision, ethanol producers are likely to locate in Idaho and Washington. Allowing money to flow freely into Oregon naturally produces positive impacts because it fails to account for all the economic flows and interactions with other states. Assuming that an LCFS program will stimulate in-state renewable fuels production without targeted supplemental state subsidies (e.g., producer's tax credits, reduced state sales tax) seems to be inconsistent with recent history.

The modeling approach seems to be one in which the LCFS policy simply provides a target for the overall emissions rate of the vehicles fleets. But the decision on how to meet the target is determined exogenously by the modelers who define pathways that quantify the amount of fuel consumed by each fuel type and achieve the LCFS target. These pathways, however, could have been chosen for the baseline and should have been chosen since they are supposedly better for the economy even without an LCFS. Therefore, it seems one is left with two alternatives, either the analysis is not legitimate or these economically better pathways (i.e., the pathways that were chosen when the LCFS is imposed and produce higher values of GSP, employment, and personal income) were not chosen in the baseline because consumers are evaluating their options using different metrics, namely utility or welfare. If the latter case is true, this suggests that the modelers should be working with these metrics rather than GDP, employment, or personal income because utility and welfare reflect the true economic condition of state residents.
The results of the analysis suggest some obvious questions. If all these economic gains are possible from implementing an LCFS policy, then why is the market not undertaking these actions in the absence of any policy? According to the analysis, there seems to be a great deal of money to be made if companies began producing biofuels in Oregon and consumers began driving alternative fuel vehicles (especially electric vehicles from the results of scenario D). If the analysis suggests all these gains, why do regulators need to impose any policy because industry will see gains in output and consumers will naturally want to use these alternative fuel vehicles because they will see a rise in their personal income?

The measured economic gains to Oregon arise because entities outside the state are assumed to shift investment toward Oregon as a result of the LCFS. The study simply assumes the conclusion that fuels will be produced in Oregon, without investigating in any way whether Oregon has a comparative advantage in producing these fuels. NESCAMU also assumed that their own client, the Mid-Atlantic and Northeast states, would be the best places to produce low carbon fuels because of their concentration of high tech firms, and the State of Washington makes similar assumptions in five of the six LCFS scenarios it analyzed. Even if each state were correct that the least cost alternative is to produce locally, then the investment would have to come from within its own borders by displacing consumption and raising the cost of living. If all states were to implement their own LCFS policies in the expectation that they could improve their economy by attracting additional investment, they would all be proved wrong. Nationally, the only source of investment is either reduced consumption or increased borrowing from overseas - that must be paid pack in the future. Thus the conclusion is inevitable that the increased investment required to produce low carbon fuels, rather than conventional fuels, is overall a net cost to the U.S. economy. Since the Oregon LCFS is consciously part of a plan that would have many states adopt similar programs, it is inconsistent to assume that Oregon will stimulate its economy by attracting investment from other states that are not adopting similar programs. But then this leads to the conclusion that if all states implemented an LCFS, the additional constraint on economic choices would reduce profits and consumer welfare. The contrary conclusion of this study violates fundamental principles of economics as well as common sense. But this flawed result follows from the failure of the analysis to consider the full effect of investment decisions throughout the economy.

Furthermore, the scope of the modeling analysis is too limited. The LCFS policy affects other states since Oregon has trade with them, especially given Oregon's lack of refinery infrastructure. Therefore, the analysis should incorporate a broader regional coverage than simply just Oregon. Furthermore, the time horizon is too short. The LCFS policy is not scheduled to simply end in 2022. The continuation of the policy past 2022 has implications for decisions prior to 2022, but to capture this, the model needs to be run out a number of years past 2022 to understand the full effects of the LCFS policy in the near-term (2012 to 2022).

Range of uncertainty

We applaud the modeling teams for using values for carbon intensities, vehicle costs, and vehicle efficiency that fall in the middle of accepted ranges. During our research on the different LCFS proposals, however, it became clear to us that uncertainty surrounded many of the key input parameters. The unknowns greatly complicated the issue. Opinions differ regarding emission factors. They also differ about the cost and rate at which major new technologies would be commercialized and the availability of resources to support those technologies. Taken together these many unknowns lead us to conclude that any analysis used to inform decision makers should consider the range of outcomes for all key input parameters so that decision makers understand the possible range of outcomes from their proposed policy.

Therefore, instead of relying on one set of assumptions for vehicle cost, fuel cost, carbon emission intensities, and fuel economy, we urge the state to build optimistic and pessimistic scenarios that span an appropriate spectrum of possible outcomes. The former scenario should contain the most likely positive outcome for each key input parameter, and the latter one should contain the most likely negative outcomes. Only in this way can the analysis capture the full range of plausible outcomes.

Assuming the conclusions

Based upon CRA's research and analysis, we conclude that the set of scenarios in the Oregon study fail to capture the full range of plausible outcomes. Each scenario assumes that some combination of technologies will succeed. Nothing guarantees this outcome. In fact Oregon presents no case for assuming that it will happen. In effect, Oregon is assuming the key conclusion from the study, i.e. that technology forcing is a given. Assuming that alternative fuels (renewable fuels such as ethanol and biodiesel) and plug-in hybrid electric vehicles (PHEVs) will be in plentiful supply and less expensive than their petroleum counterparts invariably leads to the erroneous conclusion that the GHG emission reductions sought by the program can be accomplished without incurring substantial economic costs.

The state's analysis does not justify the view that the new technologies will appear at the cost, and time, with the characteristics assumed. Furthermore, there is no discussion of technology pathways, the adequacy of incentives from LCFS to promote R&D, nor the R&D breakthroughs that will result in technology commercialization. Time and again the economic literature has stressed the profound uncertainties of R&D outcomes, but the analysis done for the state seems to pay little heed. Finally, the consequences from the failure of new technologies to emerge are ignored in the scenarios.

The interpretation of the "technology-forcing role of LCFS" appears to be the only justification for the assumption that technology outcomes will be whatever is required to make compliance with the LCFS possible at negligible cost. Nothing is adduced to suggest

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that these mandates, by one state, will have the characteristics needed to force technology to improve. In contrast, research that we have done would suggest otherwise. Assuming that "technology forcing" advances in cellulosic ethanol and biodiesel technology will be achieved in a timely fashion to enable the volumes of low carbon fuels called for by the program are overly optimistic if other states and regions proceed with an LCFS. As of today, cellulosic fuel production technology remains essentially in the development phase, and wide scale PHEV application is unlikely in the absence of a significant distribution network.

From experience, there is clear evidence that the success of technology forcing is not a given. Rather there is clear evidence from other attempts to mandate technology, e.g., electric vehicle (EV) mandates in California, that show a number of unintended responses can occur. For instance, mandates that are perceived by developers as unachievable are ignored. Local or regional mandates are met in ways that are not consistent with the policy objective such as redirecting supplies or through leakage. Only mandates that hit a "sweet spot" involving a reachable goal that is not otherwise likely to be met can be successful. Finding that spot requires careful analysis of current technology status and R&D activities, in order to aim successfully between overly ambitious specifications and specifications that will be met even without the program. Given the inherent uncertainties of R&D, there is no guarantee of success in this endeavor. Therefore, a basic premise upon which the scenarios are based is flawed.

In addition, Oregon should consider scenarios that allow demand destruction of VMT to reduce the required amount of new alternative fuel vehicle sales; and/or large costs for fuel and vehicle infrastructure to be incorporated to achieve the aimed for alternative fuel vehicle penetration levels. Currently, none of the Oregon scenarios investigates the possible risks of the mandates if none of the technologies turns out to be a silver bullet. Should that outcome occur, either the standards must be abandoned or modified, or if they are enforced as written in the scenarios the result will be to drive delivered fuel prices up to the point at which motor fuel demand (VMT) is driven down to a level consistent with available low carbon supplies. This fuel consumption and corresponding VMT reduction is more likely. Furthermore, the higher the carbon intensity of available fuels, the higher the quantity of new fuels required. This outcome cannot be fully represented in any of the models being proposed for use in the Oregon analysis, so that the costs of a failure scenario will never be assessed.

Sensitivity Analysis

Blend wall

For three scenarios (C, F, and G), Oregon assumes the blend wall can be increased to 15% by 2020. Breaking the blend wall has its own set of challenges. EPA have announced a partial waiver for MY2007 and newer vehicles after a protracted analysis period. Extension of this to MY2001-2006 remains under study and MY2000 and older and other vehicle classes/applications are not in view. These scenarios ignore the possibility that consumers will need to purchase the more expensive flexible fuel vehicles if newer non-flexible fuel vehicles or their existing vehicles are unable to burn E15. Furthermore, these scenarios assume that enough fueling stations will find it cost-effective to upgrade and be located in enough convenient locations to achieve the assumed sales.

ILUC

The analysis considers scenarios (specifically C, F, and G) that omit the emissions from indirect land-use changes (ILUC). This is an optimistic assumption and provides the biofuels for which the ILUC is omitted a large advantage.

Need for range of assumptions

The probability of the increasing ethanol content in gasoline to 15% and the value of ILUC should be studied thoroughly. The state is right to have considered optimistic assumptions regarding these two issues in its set of scenarios. But only assuming that biofuels do not result in indirect GHG land use change effects (ILUC) in several scenarios artificially biases these to favor biofuels thereby misleading decision makers on the accurate cost-benefit relationship that the wide scale introduction of these fuels entails. Indeed, the exclusion of ILUC fails to consider the overall GHG implications of biofuel feedstock choices, an omission which could negate the programs sought after GHG mitigation benefits. To be better balanced, the analysis should consider the less optimistic scenarios where the blend wall cannot be exceeded and low carbon fuel supplies do not materialize in large volumes possibly because of issues with ILUC. The clearest case is one in which there is only enough low carbon fuel of any kind that is useable by the fleet to achieve for example a 5% improvement in carbon intensity at reference case fuel consumption. Since the standard must still be met, the only alternative is reducing total fuel consumption, and this will be achieved because fuel suppliers will bid up the price of the constrained supply of low carbon fuels until the pump price rises high enough to choke off demand. This same outcome will occur if the low carbon technologies fail to appear, or new vehicles able to use them are not produced in sufficient numbers, or the refueling infrastructure required to support consumer adoption fails to materialize.

PHEV lifecycle vehicle costs

Using the assumptions for fuel efficiency, fuel costs, and incremental vehicle costs, it appears that applying a bit of sensitivity to the assumptions regarding PHEVs results in these vehicles having higher life cycle costs than conventional gasoline powered vehicles. Given the cost differentials, consumers would not purchase PHEVs unless they were subsidized. The amount of subsidy needs to be accounted for as a cost and reflected in the life-time budget. If the life cycle cost of PHEVs exceeded that of gasoline powered vehicles.

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3 Assuming an efficiency of gasoline vehicle of 35 mpg, EER of 3 for PHEVs, and VMT of 10,000/yr in electric mode (that is 2/3 of VMT in electricity mode) results in gasoline vehicles having a couple thousand dollar lower full life cycle cost assuming a 3% discount rate. Raising the discount rate to 5%, a more accepted number, results in an even greater cost advantage for gasoline powered vehicles.

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vehicles, which is clearly quite plausible, the benefits of Scenario D from PHEVs would disappear and become a cost to consumers from forcing them to purchase more expensive vehicles. As regulators have stated, they would suspend or shut down the program if costs rose too much. But there would still be some economic damage, especially in terms of sunk costs such as long-term ethanol contracts with Brazil, that would result from agents attempting to comply with the LCFS. We are advocating for a scenario to be analyzed that incorporates this very real possibility.

Reference Case
The Oregon analysis assumes full implementation of an RFS2 program by EPA. However, EPA is currently reviewing the specifications of the program in light of the lack of investment in capacity to produce advanced biofuels. The EPA has delayed its decision until year's end.

There is also uncertainty in the minds of investors which brings in doubt about the success of these other policies. For example, investors are wary of the government's resolve to continue fuel subsidies for various biofuels. Congress has already allowed the subsidy for biodiesel to lapse, which has resulted in the shutdown of existing biodiesel capacity. The subsidy for ethanol will also be up for renewal. Investors are wary of investing in biofuel projects whose success is dependent upon government subsidies when government actions have sent conflicting signals. Ignoring the risks associated with the availability of these biofuels by assuming that these fuels are readily available to meet the policies assumed in the reference cases as well as a regional LCFS policy again understates the uncertainty and costs of an LCFS policy. At least some of the scenarios examined should reflect an outcome where base case policies are not fully successful.

E85 Fuel Prices too low
The blend of E85 used in the EIA forecast likely contains little cellulosic ethanol. Therefore, if one were to account for the cellulosic ethanol used in the different scenarios, the cost of E85 would exceed gasoline. Therefore, the assumed price for E85 appears too low relative to gasoline.

Having said this, we recognize that the future price of ethanol is quite uncertain. Cellulosic ethanol is still undergoing process development, thus the costs to produce this biofuel are dependent upon the degree, the pace of technology improvement, and the success of commercial scale up. Also, the cost to produce lower emitting blends of ethanol involving conventional crops is also uncertain. Therefore, it is only reasonable that a sensitivity analysis should be performed that considers a wide range of prices for cellulosic E85 and conventional E85.

Failing to consider scenarios using a range of ethanol prices also leads to a lack of sensitivity in VMT values. By assuming the cost of ethanol is the same as gasoline on a gasoline gallon equivalent basis implies that the VMT will be virtually invariant between the scenarios and the baseline because the equation to adjust VMT, which relies on the percent change in fuel prices, will result in no adjustment.

Location of new ethanol plants
Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol production facilities will be constructed. In seven of the eight scenarios, the state assumes all new ethanol production facilities needed to meet the state's LCFS would be built in Oregon. With major production facilities recently built in Idaho and Washington, it seems that the probability of these facilities being expanded and new facilities being built outside the state rather than inside is much greater than one in eight.

Carbon Intensity Factors
The choice of values for emission factors can significantly affect the results of the analysis, and many uncertainties arise in selecting the right values to use. With biofuels, the life-cycle emissions of individual biofuels include both direct and indirect impacts. Determining direct emission can be challenging. Furthermore, accurately determining the indirect effects is highly uncertain and a subject for future research. As a result, the range of potential emission factors for a given biofuel can be quite large. Evidence of this is cellulosic ethanol and the range of estimates provided by EPA. Scenario design needs to recognize this uncertainty in the construction of the scenarios and allow for realistic optimistic and pessimistic scenarios.

Scenario D implies extremely high PHEV penetration
Scenario D seems to assume an unrealistic level of penetration of PHEVs. We built a spreadsheet model to estimate the penetration rate of PHEVs in terms of share of new vehicles sales in 2022. This vehicle turnover model estimates the size of the vehicle stock in each year by starting with the vehicle stock in the previous year and adding to this value new vehicle sales and subtracting off vehicle retirements.

To compute the penetration rates, we assume the scrappage rate and growth rate of the stock of vehicles is time invariant.

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4 Facilities are expected to turn out up to 25.5 million gallons this year of cellulosic ethanol—far below the 250 million gallons that the U.S. Environmental Protection Agency (EPA) once wanted fuel makers to produce.
We adjusted the vehicle penetration rate of PHEVs over time to hit the Scenario D target for the stock of PHEVs in 2022. The growth and scrappage rates combine to determine the evolution of the vehicle stock. For the penetration rate, we attempt to represent the classic s-shaped curve while also inputting realistic ramp rates where possible. This would require that over 30% of new vehicles sold in Oregon in 2022 are PHEVs. This incredible penetration rate in terms of new vehicle sales would exceed all historical penetration rates for new vehicle technologies.

Scenario D suffers from an additional problem. The amount of change in the electric sector infrastructure to handle the great number of electric vehicles would likely be technologically infeasible without large costs. A study produced for the ISO/RTO Council in conjunction with Taratec suggests that a total of 1.5 million plug-in electric vehicles nationwide would be feasible in 2019 and 2.25 million would be optimistic. Scenario D suggests that Oregon would account for about 10% of new PHEV sales; whereas Oregon currently accounts for about 1% of all new vehicle sales. The highly questionable feasibility of the PHEV assumption for scenario D suggests that scenario should be modified to consider a much lower penetration of PHEVs.

Questions:
Are the price increases in food and food products due to competition between food and fuel production through agricultural production captured?

The cost of living will increase as ethanol production drives up the demand for agricultural products in Oregon. This will put pressure on food prices as well. The labor and capital cost would also increase and these increases will translate into higher production costs in Oregon. Are all these effects captured in the modeling?

Furthermore, assuming the price of imports from other states remains constant, Oregon would import more, which will offset the increase in GSP through a reduction in net exports or an increase in net imports. Is this effect captured?

In the reference case, it appears that ethanol and gasoline prices are basically the same on a gasoline gallons equivalent basis. Since the incremental cost of flexible fuel vehicles is between $275 and $450 more than gasoline powered vehicles, is there not a loss in consumer welfare because now consumers must pay more for each mile travelled? Does this loss show up in the calculations of personal income or any of the other economic measures? If not, then the analysis is not accounting for all costs?

Comparing the fuel price tables in Lawrence's October 19th memo, we do not understand why biodiesel prices are correlated with diesel prices, but E85 prices are not correlated with gasoline prices. Is there a reason for this difference in correlation patterns?

We could not find any discussion as to what entities provided the investment for the new commercial infrastructure (e.g., upgrades to petroleum terminals, delivery system for E85, new ethanol plants, charging and CNG stations, etc.) required for alternative fuels and vehicles. Who funds these new infrastructure projects? Also, what activities are forgone so that these new investments can take place (i.e., which sectors suffer losses because investment is being diverted to alternative fuel infrastructure)?

Where are the costs and resource requirements of implementing an LCFS program, such as rigorous compliance monitoring and enforcement by Oregon state agencies, factored into the analysis? Without focus on compliance and monitoring the outcomes of the program will be unknown and the overall benefit of the effort unclear, if in fact, achieved.

The description of Business-as-Usual notes a biodiesel blend level of 13.5% in 2022 due to the federal RFS-2, and this is used in the program will be unknown and the overall benefit of the effort unclear, if in fact, achieved.

The high oil assumption for sugar cane ethanol in both BAU and scenarios implies that this product will be a lower ethanol stream than Brazilian sugar cane ethanol under all scenarios. On what basis is this assumption made? What in-state economic tariffs or other structure will be in place to make Oregon Waste Biomass Ethanol the lowest cost option for compliance as these scenarios depict? The August 10th Compliance Scenario Analysis slide 27 notes an Oregon Waste Food supply of 1.5 MGY (Summit Natural Energy), yet the 2022 depiction has Oregon Waste Biomass Ethanol at close to 200 MGY, is this realistic?

The chart depicting the biofuel volumes used in compliance scenarios in 2022 (DEQ website, Oct 14th meeting files) prompts a number of questions:

- The BAU, BAU High Oil Prices and BAU Low Oil Prices differ only in the displacement of Sugar Cane Ethanol with Wheat Straw Ethanol; all other volumes of corn ethanol, cellulosic etc remain unchanged. This doesn't seem logical as higher oil prices would be expected to promote increased cellulosic production due to enhanced profitability of this new sector.
- Scenario C, F and G - Mixed biofuels without ILUC, without ILUC High Oil prices and without ILUC Low Oil prices also have identical fuel compositions in these scenarios. The impact of oil pricing on increased cellulosic production is not included.
- Scenarios A-G have a fixed quantity of Oregon Waste Biomass Ethanol regardless of inclusion of ILUC or oil pricing, implying that this product will be a lower ethanol stream than Brazilian sugar cane ethanol under all scenarios. On what basis is this assumption made? What in-state economic tariffs or other structure will be in place to make Oregon Waste Biomass Ethanol the lowest cost option for compliance as these scenarios depict? The August 10th Compliance Scenario Analysis slide 27 notes an Oregon Waste Food supply of 1.5 MGY (Summit Natural Energy), yet the 2022 depiction has Oregon Waste Biomass Ethanol at close to 200 MGY, is this realistic?
- What pricing assumptions for sugar cane ethanol have made them such a low proportion of both BAU and scenarios despite their ready availability and carbon intensity benefits?


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VMT Sensitivity to Fuel Prices

We are confused how the modeler's VMT sensitivity to fuel prices was applied. The October 19th memo from Michael F. Lawrence of Jack Faucett Associates (JFA) states: "The analysis of Oregon's low-carbon fuel standard pathways retained an elasticity formula already built into Vision. This elasticity formula assumes an elasticity factor of -0.1, meaning that a 1% change in the fuel price encountered results in a -0.1% change in VMT driven."

Scenarios C, F, and G have very different fuel costs, but they consume exactly the same total volume of fuels as stated in table 29 of Jennifer Pont's October 18 memo. Since this table's numbers are on a gasoline gallon equivalent basis, this equivalence implies that these scenarios have the same level of VMT. This result seems to directly contradict the claim that VMT was adjusted according to changes in fuel prices.

In Scenario G, which has the highest fuel prices relative to gasoline prices, presumably should have lower VMT than scenarios F and C. Is this true, and did the model account for the loss in consumer welfare from traveling less? My suspicion is that the model did not account for this loss. Furthermore, scenario G confounds the impacts of the prices by also lowering the carbon intensities for biofuels and allowing an increase in the blend wall. This reduction offsets the impact of the fuel prices so one cannot understand the full impact of gasoline prices being below biofuel prices.

Conclusions

The linking of the VISION and REMI models is not internally inconsistent. The REMI model fails to fully account for the economic impact of investment decisions. The flawed modeling approach means that the reported economic impacts of the LCFS are erroneous and misleading.

The design of the baseline and scenarios biases the analysis and understates the costs of a regional LCFS policy. The design of the cases ignores a number of important issues and as a result assumes greater flexibility and lower costs to comply with an LCFS than actually exists.

The design of the scenarios creates the image that policymakers only need to decide between low cost biofuels and no additional cost electric vehicles on a life cycle basis. Important issues such as fuel infrastructure constraints (e.g., blend wall constraints on the use of biofuels and electricity grid upgrades), consumer resistance to purchasing new higher cost vehicles are washed away by the convenient choice of assumptions.

The true issue should be how much more of a GHG reduction benefit will such a program deliver over what is projected to be accomplished by federal and state programs already in place, and at what additional cost. The Federal RFS2 program will deliver GHG benefits federally. Oregon states concern that their fair share of the RFS2 will not be realized in state is an unrealistic basis on which to base an LCFS program of this complexity and cost, and the financial analysis provided fails to represent the true cost-benefit analysis on this basis.

Failing to present a realistic "worst case" economic scenario as part of this analysis only serves to reinforce the erroneous conclusions pointed out above.

Thus the Oregon study, as currently formulated, is not defensible as its results rest upon an inappropriate model structure and restricted set of input assumptions and scenarios. It will provide policymakers with a one sided and unrealistic view of the consequences of an LCFS policy.

November 16, 2010 Advisory Committee Meeting

- How are out of state and in-state fuel production assumptions made? **Response:** We created the compliance scenarios to set the bounds of maximizing the number of ways that people could comply with the program, and we tried to keep those scenarios realistic.

- How proprietary is the conversion tool to translate REMI inputs? Is it a transparent process that produces outputs that the committee can review? **Response:** (JFA) It’s not proprietary at all. The VISION model produces changes in the vehicle fleet, so it tells us over time how vehicle fleet technology will be changing, which then needs to be converted into the right kind of dollars for the REMI model to take in as changes to the baseline.

- I just want to make sure that the report has enough description of the inputs and outputs for readers to conduct a critical analysis of the information and understand the range of what could be expected out of

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8 Pont, Jennifer, "LCFS Scenarios Infrastructure Costs," October 18th, 2010.

[Type text]
that translation. **Response:** There are assumptions for example such as a vehicle price today and in the future, and all of those will be in the report.

- In terms of population growth, are the projected numbers both in terms of the way the population itself is growing or are you looking at it relative to changes in the rest of the country? **Response:** (JFA) It is both internal population growth from the existing population in Oregon and it also includes migration out of and into the state. So it is a population forecast from now until 2022 and the REMI model is a national model and can be broken down into various sub-regions, groups of states, individual states and the county level. What the REMI output tells us is that the Oregon population will be a bigger proportion of the national population in 2022 than it is now.

- I am curious about the forecast that energy use (in Oregon) will grow by a third; is the per capita energy consumption flat? **Response:** (JFA) Energy consumption is growing less rapidly than state product and we are becoming more efficient over time at consuming energy. With regard to output per unit of energy, if we look at history over the last 30 years, that has been the period in which the most dramatic change in our economy has occurred, associated with efficiency in energy use. The costs of energy and worries about scarcity have changed the way we think. Part of that is driven by the market, part is driven by federal and state regulation, but we use energy much more efficiently today than we did 35 years ago when we had our first energy crisis. In theory there may be a limit to efficiency, but at present we are still improving energy efficiency.

- I realize that maybe energy use per capita is an inexact measurement because you could say on the one hand that if you aren’t reducing energy use per capita then you’re not doing much in the way of conservation, but on the other hand you could say that there could be ways that individual productivity is going up faster than energy use per capita. **Response:** (JFA) Individual economic productivity goes up over time. Between now and 2022, productivity will increase which will make the output per capita go up. That essentially is where all the wealth comes from, from being more productive in what we do. If we didn’t have productivity increasing, we’d just be going along at the same pace.

- We’re saying energy consumption will grow by a third over twelve years with a population growth of 33% - is this reasonable? **Response:** (Pacificorp) Yes that is a reasonable assumption, given the time period. **Response:** I think this is a fundamental point. We either have to compare Scenario H to a modified baseline that also has compliance with RFS2 with out of state production or drop scenario H because its giving a distorted impression that adopting a low carbon fuel standard would cause compliance with the exiting RFS2 to change from what it would be in the baseline. I think what Randy came up with would be the real result of scenario H, that it would show flat, which is definitely worse than all the other scenarios. Which you would assume, if compliance with the LCFS is done primarily through out of state production, we would see no change really from what we’re doing today. So I think we need to make one of the two changes mentioned, because we can’t leave it like it is.

- I disagree with Andy on this, specifically that there would be no impact from Scenario H. There is a high probability that if the LCFS isn’t implemented in the state, the production won’t take place in the state, and that LCFS will also drive up prices significantly to the consumer which will have a negative impact within the other benefits within the other scenarios that show job growth from the construction of production plants. So compliance scenario H should show a significantly larger negative impact to Oregon. **Response:** What we’re doing in this scenario is an analysis of the comparison of the business as usual to the scenarios, and the way you just described that was not comparing the business as usual to the scenarios. What I am saying is that the business as usual compared to the LCFS where the production is not instate but the cost impacts to the state are there. **Response:** But that’s not what is causing the dip. What’s causing it is that under the business as usual case there is an assumption that some of the compliance with the RFS2 is from in state production, and when you add the LCFS, that causes the
production that would have been in state to move out of state, and it is not a realistic assumption to assume that the standard, which actually creates an incentive for production of biofuels would cause existing forecasted production to somehow move out of state. That is the implication of comparing scenario H to the business as usual case. They are built on different assumptions, and it is an incorrect comparison that results in this artifact of the model that requires us to either drop it or change the business as usual case. Just like, for example, with the high and low fuel price, we changed the fuel prices in the business as usual case and in the scenarios to be able to see the difference. In the case of scenario H, you’ve got to change the business as usual case so that it assumes the maximum amount of out of state production for complying the existing RFS2 against the maximum out of state production for complying with the LCFS, and then you’ll see in that case very little if any difference.

- What the economic analysis has made clear is how important in-state production is in providing economic benefits of this policy, and I know we went over all these scenarios, but I don’t have enough experience to understand why so much in-state production would occur, because the policy as I understand it incents the use but not the production of low carbon fuels. And because production is so critical to the benefits, I question if we have the ability to connect those dots. If production all goes to Washington or Idaho, then we’ve met our carbon emissions reduction goal, but we haven’t seen the economic benefits. It seems like there needs to be a way to incent, through policy, in-state production because it’s so important. The incentives that have been in place are now being diminished, and those have been powerful incentives and are less so now, which leads me to ask what confidence are we going to have with regard to the benefits we are seeing? Response: The LCFS needs to be neutral on that point, and that is important because fuel is an interstate commerce, and we can’t provide extra credit for fuel that is produced in Oregon. It is really important that our policy is neutral with regard to where the fuel is produced. The GREET model is going to provide better credit for fuels transported shorter distances, but that won’t distinguish much between fuels produced in Washington and Idaho, but probably from further away you’ll see a net carbon penalty from transporting fuel a long distance, but that doesn’t mean that it couldn’t be sold here. The reason for bracketing the compliance scenarios for the analysis from all in-state to all out of state fuel production is to show you the range of what could happen. Other policies that the Oregon Legislature and others may take to encourage development of low carbon fuels in-state may drive where the production occurs, and having a program that increases demand is going to be necessary for that to happen, but I think they will be separate driving policies. That’s why it is so important that we show in Scenario H that the worst-case scenario where none of those things happen and all production is out of state, is neutral, which is the worst-case scenario for the program.

- If you look at some of recent the reports on ethanol production, once cellulosic ethanol is commercialized, the most economic production facilities are expected in the South. The USDA study says that nearly 50% of production will come from the south, then a significant portion from the Mid-West, and a lesser amount from the Northwest. So some incentive is needed to overcome that differential on the costs side.

- I still have a question regarding Andy’s suggestion to change the business as usual in scenario H and not including forecasted in-state production for compliance with RFS2: How is taking any future production of RFS2 capacity that could be forecasted make it a better comparison? Response: (JFA) We’re saying it the opposite way. You’d want to leave the in-state production alone. Response: What we’re saying in scenarios H is that if we had any additional biofuels that need to be produced to comply with the LCFS above and beyond what would otherwise be required to meet the RFS2 or other standards would occur out of state, then I think (the graph for Scenario) H would be flat. But what’s happening in (scenario) H is that we’re taking production that in the business as usual case was assumed to be in state and moving
it out of state, and that doesn’t make any sense because nothing in the LCFS policy would cause that to happen.

- As far as tracking statewide economic benefits, it seems like all of the scenarios are currently aligned, keeping Oregon dollars in Oregon, so if that’s what scenario H can achieve, then it serves a purpose, of determining whether or not we need to change the baseline to do that, but there is some validity to having some version of scenario H, that compares the dollars estimated to stay in Oregon under the other scenarios, and in scenario H dollars associated with production leave the state, which raises the question of where do those dollars go.

- (Chair) Suppose this regulation were not intended to achieve carbon reductions but was intended to foster economic activity in the state, then the worse case (baseline) would be that this regulation is fully ineffective and RFS2 is going to achieve the goals, and the LCFS wouldn’t have any positive impact, which would be the flat line on the graph. The best case scenario would be a whole lot of capital investment and the reality might be somewhere in between. So I agree with the bounds created by the scenarios. **Response:** (JFA) REMI thought they were running the same scenario against itself and that wasn’t quite the case, so I think that will just need clarification. They just didn’t have enough time to get that redone before this presentation. We can reproduce this scenario, and it would show essentially a flat line. **Response:** We will be fixing that and will revise and repost that graph.

- Do the electricity prices remain constant in the model? **Response:** (JFA) That’s correct, there is no change in the electricity prices in the model. Where do the fuel prices used in the scenarios come from? **Response:** (JFA) Fuel prices come from the Department of Energy Annual Energy Outlook.

- In Scenario D, what causes the decrease in heavy duty diesel vehicle use? **Response:** (JFA) Each of the scenarios has a set of alternative technologies on the road in 2022, and this reflects less diesel engines being bought and replaced by other technologies. And when you say CNG, do you mean CNG and LNG together? **Response:** (JFA) Yes, all natural gas.

- Is the price of gasoline expected to go up at a different rate than electricity? **Response:** (JFA) I’m not sure about the rates of change, I would need to look those up. Both the gas price and the electricity price come from the EIA.

- What happens in scenario F where there is a dip and then a rise, and also scenario C – what is going on to cause this? **Response:** (JFA) Change in plant spending over the business as usual level, so it’s a variation between how much plant spending occurs. **Response:** (JFA) I believe the questions was why scenarios other than H have dropped below zero – is that correct? Yes. We’re looking at slide 26 which is the plant spending slide and that slide shows that in scenario E where in 2021 there is lower investment than the baseline. **Response:** (JFA) That’s accurate, we received our input and assumptions from TIAX, and those assumptions including in the baseline a certain number of ethanol biodiesel plants and I believe E included more ethanol plants in 2019 but one less biodiesel plant, if I remember correctly. Or it may be the reverse, because the strategy in D had a stronger focus on heavy duty than light duty. **Response:** And the same thing happens in scenario B, which is a mixed biofuels scenario with indirect land use, with the same kind of explanation? **Response:** (JFA) Yes, we see that reflected later in the overall costs when you’ll see that B has an overall impact that drops below the others in 2021, so this drop will manifest itself again in other slides, and the reason is the number of plants that are anticipated to be constructed.

- What does aggregate demand tell you that is different than what state product tells you and how you would think about it? **Response:** (JFA) It doesn’t tell you anything different in terms of the analysis. It does tell us how the policy can be attributed to market value within the state? **Response:** (JFA) It tells you as you look across all of the 70 sectors in the REMI model it tells you which sectors are shrinking
and which are growing relative to the baseline. But in this presentation, it is summed across all of the sectors, so state product stays the same.

- **(JFA)** We have changes in energy consumption by year by scenario, and they come from the VISON model. It is not in the text of the report, but can be found in the appendices.

- Do we have in the appendix the aggregate demand broken down by the 70 sectors? **Response: (JFA)** That is correct. It has the change in output, mostly what you see are zeros in the matrices because the change is very small. In order to see the change in those sectors you have to look where there are significant changes such as petroleum or agriculture. There are no negative numbers because the market is larger in the future than it is now, so it is a relative change from the baseline. The input output model which is a piece of the REMI model called the technical coefficients is the measurement of the inputs required to produce the desired degree of outputs. If the change in output of the product the technical coefficient then measures the amount of that input that’s required.

- One of the problems we talked about previously is the unique situation that none of the petroleum used in Oregon is produced in the state, so the negative economic impacts that would fall out from an LCFS would be felt in Washington and other states. That is a big gap in this analysis from WSPA’s opinion, in that you’re only looking at a small window of the overall impacts. **Response: At one point we talked about whether we could look at the conclusions of Washington’s economic analysis and somehow make some comparisons. Washington used a 15% blendwall where we used a 10% blendwall, and they had different assumptions about land use, so it would be interesting to compare our scenarios and analysis to theirs with regard to petroleum production in Washington. Can we get Washington’s results and somehow compare their results to the results of our analysis? Response: (Mike, JFA) I don’t know the specifics, but we can look that up.

- The scenarios were very narrow and the Washington inputs in to the REMI model were almost identical to the Oregon inputs because TIAW was also their consultant, so the input generation work was the same and in general the oil industry doesn’t think the projections used are realistic and we feel that the cost of implementing an LCFS program will be a lot higher than what is being modeled in the compliance scenarios, and that isn’t reflected in the overall program. I don’t think that the REMI work that I’ve seen from Washington is as complete as the work that is being presented here today. The Washington work just shows the final outputs, which is very difficult to understand how they came to the conclusions they reached. **Response: (Chair) So for example, you don’t know if there is a change from baseline in the Washington model in refinery jobs. Response: I think we should try and get that if possible. I don’t know whether it becomes a comparison in this report or if we just try and summarize Washington’s approach found, but I think we need to see that.

- I want to reiterate so that we all understand- would scenario H be corrected in terms of the capital investment costs related to the production plant issue, and as a result prices go up, and as all export there will still be a small negative just not anything to this scale. So it’s not completely neutral, but it’s very small. **Response: (JFA) If the price of alternative fuel which is imported is higher than the price of petroleum fuel that would have been imported, then households will either spend additional dollars to purchase their fuel or they will drive less, and that will result in some negative impact. Is that the case though? Is the imported fuel price differential as you suggested there? Response: (JFA) It is not. Right now the US Department of Energy forecast show those energy equivalent bases the price of ethanol gasoline to be equivalent. Response: Because this analysis is looking at the differential between base case and the scenarios, when you have a high fuel price that goes both into the base case and into the scenario, so that even though petroleum costs more the biofuels are also going to cost more as well because of the petroleum input costs, so the relative difference stays similar and therefore the scenario differences are similar but if you look at the absolute impacts of high fuels prices you would see a bigger
impact, right? So is a fair way to look at them to say that there isn’t much difference between them? 

Response: (JFA) Yes, you could look at it that way. The higher fuel prices change the amount of activity. Up until the recent financial crisis, there has been no bigger driver of our economic downturns than increases in fuel prices. If you look at the history of economic cycles in the United States, you will find very consistent increases in energy prices leading into recessions and slowdowns in the economy. The economy is very sensitive to energy prices, and that should be expected.

This is one of the shortcomings that this analysis is showing because you’re not looking at a baseline with the normal projections and then comparing with a higher fuel price. You’re inflating both of them, and you’re not getting the true impact on the economy. It would be more realistic to look at the business as usual price under your standard scenarios and then compare that to a higher fuel price driven by an LCFS. I know we talked about this at the last meeting, that there are no other scenarios that DEQ wants or can afford to run, but I think what’s missing here is the impact to the Oregon’s citizens.

Response: It sounds like you’re not necessarily following what’s in this scenario. It’s not a higher fuel price driven by the LCFS, it’s an assumption that crude oil prices are higher. And that wouldn’t be driven by LCFS, that’s driven by other factors. The question at hand is how does a world with higher crude oil prices react to an LCFS, versus a work with lower crude oil prices react, and that’s why you have to put the change in the base, otherwise you’d be making some assumptions about how the LCFS would affect crude oil prices. I guess I misstated my position. The alternative scenarios that I was talking about is when you have your business as usual pricing and compare that to a high price because of the LCFS. That is probably more realistic in terms of impact on the state of Oregon than anything being shown in this analysis.

It’s like Scenario H where the fuel price goes up? Response: (WSPA) We’re building a picture here where we’re assuming plenty of fuel will be available, which I think is a big questions that we aren’t addressing here. We’re saying we’re going to build these plants in the state of Oregon, and there’s a big question around that assumption as well. And then on top of that, you’re assuming that the price of the alternative fuels are going to be at or below the price of gasoline, which we do not believe to be an accurate assumption. So you’re building rosy assumption on top of rosy assumption, and coming out with results that contain the inference you’ve put in there. I can’t argue with the results that Mike is presenting here today, but I can argue with the assumptions that went into the analysis and whether they are realistic, when comparing the results of this analysis to other sources of research that suggest a very different outcome. Response: I think what I hear you saying is if the LCFS drives demand high enough for alternative fuels that are not available, then the price of alternative fuels will go up above what the Energy Information Administration’s projections are for crisis, then that could change the scenario. Is that correct? Response: (WSPA) Yes, that’s one component, So if there was a fuel availability question, then the price question, and in-state job development that are all on the rosy side in the scenarios being analyzed. Response: In-state we’ve bracketed that, but in terms of price and supply, they are interconnected and therefore really the same thing. So under your scenario, there’s a shortage of low carbon fuels and because we have this requirement for low carbon fuels, the fuel providers have to buy it anyway, and their buying it (out of state) at higher prices than were predicted. Response: (WSPA) And then you have to factor in the carbon intensity question, and it doesn’t look like corn-based ethanol is going to address the carbon intensity requirements, and cellulosic ethanol is not yet commercialized on a national level, so you’re driving that limited supply significantly higher in cost perspective because of that, not even including the cost of production of that alternative fuel, which is still a lot higher than what this is showing. And on top of that, you’re saying that the production plants will be built here, which I don’t think is a realistic assumption. So as you roll this thing out, it is going to look ten times as rosy to the layman than I think reality will show them. Response: So your quibble is not so much with the economic analysis itself, but more with DEQ’s projections regarding availability of alternative fuels that
informed the compliance scenarios. Response: (WSPA) Or at least bracketing it with looking at a reality scenario that is the way I just described. That would give you your lower bound, which we don’t see here. Response: One point I’d like you to consider is that we have designed this program so that that scenario can never happen because of our deferrals and consumer cost safety net. So if we had a program that had an absolute mandate regardless of supply, then I think your scenario could be considered the worst-case scenario if it were to come true - if the supply were not available we would defer the requirements, so its built into the scenario that that can’t actually happen. Response: (WSPA) That still causes negative impacts, because if you’re talking about that last discussion that isn’t going to happen. Because those off-ramps are in there, but they won’t be triggered until a year’s worth of data (for the consumer cost safety net) can be analyzed, and from the stranded investment perspective, as a regulated party, we’re going to have to start investing a lot sooner than what is being shown here in order to comply, because you have to put all the infrastructure and everything else in place. And then if you shut it off, all that money is wasted. So there significant complexity that we all recognize, but there are also significant costs that I don’t think we are accurately addressing.

- I think your view of the status quo is pretty rosy. Increased demands for fuel worldwide are now competing with our needs. And for you to say the LCFS is going to create costs, I look at it and see more consumer choice and supply options. And with increased domestic consumption, you’re not sending money for transportation fuels overseas, so I just don’t see how more fuel availability would not support lower fuel prices across the board. For petroleum, I see it actually benefiting from an LCFS, because you have more options. I can sell biomethane much cheaper than gas. Response: (WSPA) I can’t argue with you on that. What I’m saying is that those alternatives are out there, if they are truly economic, they are going to happen with or without and LCFS. An LCFS just adds a lot of complexity, drives a lot of costs unnecessarily, and doesn’t need to be put in place. I would whole-heartedly disagree because of the monopoly position the petroleum industry is in. Response: (Chair) Some of this is getting into policy stuff, but is there anything more we need to discuss in order for Michael to finalize the economic analysis? It sounds like as a whole the committee has been okay with the way the scenarios have been run. I think some of these points about potential consumer costs are at the margins when the largest impact is seems still revolve around whether production plants are built in-state. You will have an opportunity both in the appendices and additional comments to say, even if you’re not disagreeing with the economic analysis work, that you have some differences with how the scenarios were put together or about the inputs.

- (On the phone: Paul Bernstein, CRA) I’m having trouble with the analysis overall and the sign of the economic impacts. Can you explain why, when you constrain the economy with a LCFS standard, how that leads to economic growth in the state? If I understood you correctly, part of the argument is that you get investment coming into the state from out of state, and that helps the Oregon economy. But there also seems to be something on the consumer side, and I don’t get that piece. Response: (JFA) When we look at economic or environmental or labor regulation, what we normally expect is a cost to be imposed on the economy and the benefits are much more difficult to measure in that they come in the form of prevented health effects of avoided loss or injury, so it’s always a challenge when conducting a regulatory economic analysis to measure the benefits side, in this particular case, the LCFS will provide benefits of reducing carbon emissions in the state of Oregon, but trying to measure the benefits of that change is extremely difficult, and that may be why that has not been addressed by this panel. But the normal path to analyzing the benefits would include identifying what those benefits are, determining how to measure and quantify those benefits, and take those things that aren’t quantifiable and make them as quantifiable as we can. Are you saying that the model shows what would happen if the U.S. as a whole
adopted an LCFS, would you show that GDP goes down in the U.S. if there is no foreign investment into the U.S., or would GDP still increase if the nation adopted an LCFS. **Response:** (JFA) That’s a different question that has been addressed by your firm, Paul. In your assumptions the supply of fuel would not be available to meet the national LCFS. Even if it were, if this is good, then why aren’t consumers and businesses doing it now. Because it seems like there is some much money on the table, if I look at your analysis, is the assumption that there are so many market failures? From a common sense standpoint, I’m not arguing against trying to reduce carbon emissions, I’m just looking at this from the perspective of a cost-benefit analysis, and it’s hard for me to understand as we get the benefit of reduced emissions how that comes without any costs. To my question about a U.S. level policy, I understand if you can induce investment from outside of Oregon into the state of Oregon, that’s a benefit, just like any other type of policy, such as for manufacturing. **Response:** (JFA) That’s a good analogy. In this case we’re talking about the opportunity for using resources in Oregon to produce low carbon fuels. As for why that doesn’t happen on its own, as economists we have faith that the markets will create these opportunities and efficient solutions. We do think that the transportation market has market failure characteristics that are associated with the long term existence of growing supply and the ability of many years of the petroleum industries’ ability to provide product at a low cost. One of the things that does is discourage the development and use of alternatives. Imagine the world today if there were no negative externalities associated with petroleum consumption. Carbon is a negative externality associated with petroleum consumption, and the states of California, Washington, Oregon and many others have made the reduction of carbon a primary policy for their governments. And that is that state that Oregon EQC finds itself in today, with the Legislature ordering it to look at this opportunity. And what we’re seeing here in Oregon is the Oregon legislature trying to reverse this negative externality to force the technology into place that would have that occur to assure a market that the investors in the alternatives fuels would be able to sell their products, taking away the uncertainty of them being able to sell their products in the market place, which then encourages investment. **Response:** I think part of the crux of his comment was if in fact over a long enough period of time alternative fuels were cheaper and had other benefits, the market would go towards then without the regulation. And what I had in mind as a response which I would like to check with the committee and Paul on is that there is a certain inertia in our current fuel distribution system that results from the number of tanks, for example, that retailers have then determines how many types of fuel they can supply, the vertical integration of the industry or who owns what resources, but basically who would end up having to pay initially for more access to alternative fuels is sort of a barrier to that happening, even though once those fuels are made there’re might be a net benefit to the economy as a whole from having a more diversified fuel supply. So one of my thoughts about having a LCFS is that it helps overcome that market inertia by creating the demand and essentially requiring fuel suppliers to pay for their initial investment in order to make the fuel market more open and overcome that market failure you’re talking about. **Comment:** I’d second that because one of the things Paul said was that this policy would create a constraint, and I think it’s just the reverse. It’s creating a performance-based incentive to reduce the carbon intensity of our fuels, and the goal would be to spur ways to increase and diversify supply. **Response:** If there are benefits (from LCFS) overall to the economy, it might still be negative on some sectors, particularly for the petroleum sector relative to the business as usual case, and so they wouldn’t necessarily have an incentive to make those investments even though it might benefit the economy as a whole. Does that make sense as a way of thinking about this? (Paul Bernstein, CRA) As you’ve pointed out, there are a lot of costs associated with changing the system and that’s where I question the modeling results. The externality that you mention regarding the emissions is a market failure in itself, but as you said the policy isn’t addressing that. But that market failure wouldn’t be what’s accounting for implementing the policy and seeing positive GDP. Addressing that market failure should be seen in the reduction of CO2 emission. Again, I still question the sign if the
analysis of what you’d find if you used the modeling tool to run a national policy. If you ran a national LCFS and got positive GDP, it just doesn’t seem to make sense to me. What makes sense to evaluating whether an LCFS policy is bad or good seems to be ranking it against other policies that reduce emissions and understanding the costs of the other policies, and whether those exceed the benefits of reducing carbon emissions. But again, I have a hard time believing that you would get benefits on the costs side by implementing the policy. Response: Your response was with regard to the externalities, but what I was trying to point out was the difference in who benefits and who pays. So if we had the assumption that the diversified fuel supply where some of those fuels were produced in the U.S., was going to provide a net economic benefit including the benefit of the construction of the fuel supplies as well as the benefit of not shipping dollars overseas for imported fuels, the market failure was that those who would have to make the investment to make that happen wouldn’t be the ones benefiting, but the benefit would come to others. That could explain the scenario where you have a program that does actually create real economic benefit that wouldn’t be adopted by the market without this incentive being created. I didn’t hear your response to that thought. (Paul Bernstein, CRA) I suppose that’s possible. But if you think the markets are efficient, then the investment today is going where it gets the greatest return. So again, thinking about the U.S. as a whole, or even Oregon, it makes more sense for investment in Oregon to go to Intel or (electronic) chip manufacturing or something else where there is a competitive advantage and you’d rather import less chips but import more crude oil because overseas they have a competitive advantage in producing crude oil. This is what bothers me about the REMI modeling formulation and the bias of these scenarios, is that it seems to be making the assumption that investment just comes into the economy, and there are many scenarios where it would seem prudent to ask why people invest in this. They may find that they can get a greater return doing something else. And if you’re forcing them to invest in some other market, namely the low carbon fuel that is likely a drag on the economy because without this provision the market has determined that investment is better placed elsewhere. Response: (JFA) You make a good point, but what we need to keep in mind is the big picture about competitive advantage. What you’re suggesting is that the purchase of foreign oil from low cast resources, the production of oil in Saudi Arabia maybe costs six or eight dollars a barrel, and is sold in the market place for forty, sixty, eighty, one hundred, we don’t know what it will be sold for tomorrow. Do we have a shortage of petroleum? Are we over the half-way point of having consumed all world oil reserves? We don’t know the answers to those questions, but what we do know is that there are substantial economic losses in the U.S. when we import petroleum. One estimate made by the Oakridge National Lab for 2005, was that if oil prices were thirty five to forty five dollars per barrel, the economic losses in 2005 would range from $150-250 billion dollars. Oil prices in 2005 were considerably higher than that, so the economic losses would have been greater than that estimate and roughly twice that amount in today’s dollars. If we could make our trade balance by exporting more product to balance those external flows, we could keep our economy moving forward and I think you would be correct. But the fact is we run a substantial trade deficit a result of our oil consumption, and there are substantial externalities associated with that oil consumption, and changing that mix through government policy can result in reducing those economic losses, which in essence are economic benefits. So it’s not clear to me that a national model run would not produce those benefits if we could produce those products domestically to allow transportation and/or to allow collective power production at relatively the same costs as we import petroleum fuel. I think it is important to consider the scenarios that biofuels production could come from out of state or in other words, the reliance of the policy producing positive GDP impacts on investment from out of state, and if that investment doesn’t come in then I would think you’d see a loss in economic output.

- I want to follow up with what Andy said, that has to do with the naiveté that goes into assuming that these markets are open enough that single day commodity price will provide investment into the market.
I think that foundation of an argument for a scenario is ludicrous on its face, given the history of petroleum’s role and the distribution and supply. I understand that there are a number of people who believe that markets are quite pure in terms of attracting investment to highest and best or most return, but if you look at any economic analysis completed on the energy efficiency market in Oregon, there are industries with half a billion dollars worth of projects that have a 20% or greater level of return, And so we really have to look at we’re setting up and designing this as an incentive to provide assurance to attract capital. And these scenarios point out that if there is this assurance of a growing market share for a particular commodity that there is highly likely to be capital

- If Washington and Idaho and California all adopt an LCFS, what’s going to make Oregon be the place where production plants are built? **Response: (Clean Energy)** *Why does it always have to be about production plants? What about infrastructure, fueling, etc.?* We’ve heard today that the biggest economic benefit will be from the construction of those plants. **Response: (Clean Energy)** *This is all, in the end, an oversimplification. There are significant amounts of inputs that will occur, and the amount of infrastructure and outlay that my company alone will invest in regardless of whether or not we build a plant for LNG in or out of the state of Oregon, there is going to be a lot of operational expenses, drivers that will be based here in Oregon, like stations. There is a significant amount of capital that goes into fueling stations and there will be significant construction costs. The motivation to locate a production plant in Oregon is that it reduces the transportation costs for moving the final product. I lose carbon benefits when I have to truck fuel from farther away. And there are significant opportunities in the state of Oregon for renewable sources of natural gas, such as landfills and sanitation plants.***Response: If Washington and other states also adopted a LCFS, there would be more demand for low carbon fuels, and unless Frank’s scenario came true where there wasn’t enough capacity to supply it, there’s going to be more demand and in all likelihood you’d have plants built in all of the states that would be developed and we do have a scenario where there are no new plants, under scenario H, which I’m assuming it will be adjusted and will show no plus or minus, (2:52:36) which for an environmental regulation is a huge success in that in most cases, when you’re trying to address some market externalities there is an actual cost and in this case if you got away with no cost an no benefit, I think you could declare success. And then in all these other scenarios that it’s quite possible that there could be significant economic benefit if complementary policies are put into place to draw those plants to Oregon, but in my view if those plants are built in Washington, that’s great as well. The bottom line is we’re trying to reduce the carbon intensity of fuel and if we can do that without having a negative impact, that’s great. Certainly we’d like to see some economic activity in Oregon as well and it’s possible with the right complementary programs.

- This analysis makes it clear what the economic benefits are so it’s an easier case to make to legislature to either strengthen the policies we have to encourage companies to develop in Oregon or to develop new policies to say that our economy needs jobs and here’s a good way to do it. **Comment from Audience:** (Mike, BP) There has been a lot of discussion of assumptions, which is understandable, but some take the position we might already have enough mandates, with the ethanol mandate and the biodiesel mandates for both Portland and Oregon statewide. With all of those in place, have we seen facts to back up the assumptions being made, for example, increased investment, health of the industry, increased jobs, etc.? **Response: A piece of the answer to your question is that we already have investment in biofuels being produced in Oregon, and it’s largely due to the existing RFS that creates demand for those products. The issue that you’ll see in the graphs is that just meeting the current national and state Renewable Fuels Standards is not going to achieve the needed reductions under the LCFS, and meeting the additional requirement of the LCFS, remembering that it is back loaded intentionally to give time for developing new facilities but at some point in 2017 or 2018, more investment is going to be needed to meet it. So theoretically you could also achieve that by strengthening the RFS requirements, but the idea of the
LCFS is that we’re not going to dictate winners or losers, but are going to let them all compete. (Chair) I think it’s important to remember that the job given to JFA was fairly narrow and doesn’t cover a lot of the discussion we’ve had about national policies or other ways to get carbon reductions or what the costs and benefits of other programs, and a lot of it does just focus on Oregon, so we aren’t looking at costs out of state and it certainly should help inform the Legislature when they look at this program that at least, even as we get a carbon benefit, it looks like our worst case scenario is relatively close to business as usual, and our best case scenario is that Oregon sees some economic benefit from the LCFS. I think JFA has done a great job with limited time and resources, and those who tend to agree with the scenarios and assumptions will say the analysis is good, while those who disagree with the scenarios and assumptions will say this is why we don’t think the analysis is very useful. But nonetheless, at least so far I’ve heard all around that people have recognized the quality of the work the JFA has performed in terms of working through the given assumptions and the inputs, and that’s what we hoped for.

Summary of written comments from advisory committee member or alternate December 1, 2010

- With the results of the economic analysis, it is clear the LCFS will be extremely beneficial not only for Oregon’s environment, but also for Oregon’s economy. The state currently exports over $5 billion every year for transportation fuels. While the LCFS is a performance-based standard, it provides a market incentive for locally produced fuels (while also allowing for low-carbon fuels to continue to flow in from other locations), which will create net jobs, make net improvements for household income, and be beneficial for Oregon’s Gross State Product. This is a clear win for Oregon.

- Tiax and Jacket Faucett and Associates have done a good job. They have been thorough and have responded well to inquiries.

- We hope that the economic analysis will be accompanied by a well-written executive summary that clearly lays out highlights of the study, including the benefits the LCFS will bring to Oregon on job creation, household income, Gross State Product, and other relevant measures. The report could be clearer in laying out the compliance scenarios--perhaps with a chart that helps compare and contrast each scenario or at least formatting that will be easier to read if it is text only. The report should also explain that the scenarios were meant to "bracket reality" to help explain why there isn't a "most likely" scenario.

- In the Introduction, explanation of a "performance-based" standard could help describe the LCFS and how it differs from a volumetric blend requirement.

- In general, it would be very helpful to have more interpretive text accompany the graphs. For example, The Changes in Income under Eight LCFS Compliance Scenarios could be accompanied by a caption that says, "For 7 out of 8 scenarios, there is a positive net impact on incomes ranging between $100 million and $700 million per year throughout the program timeframe."

- The economic analysis clearly shows positive impacts to the state's economy based upon a robust low carbon fuels industry in Oregon, particularly when low carbon fuels are produced within the state rather than imported from outside the state. While the LCFS establishes a strong incentive policy for investment and new business in Oregon, ZeaChem believes that more can be done to incentivize low carbon fuels within the state. ZeaChem understands that additional programs would likely be implemented outside of the DEQ's authority but can be closely coordinated with DEQ's efforts to implement the LCFS successfully.

- Recommendation: DEQ, along with the State Legislature, Business Oregon, Oregon Department of Energy, Oregon Department of Agriculture, and others, should continue to work closely with vested stakeholders including low carbon fuel producers and feedstock providers to promote low carbon fuels
produced in Oregon. Working together, Oregon can establish itself as a national leader in low carbon fuels production.

**IX. Potential Impacts to Public Health and the Environment**

Summary of written comments from advisory committee member or alternate December 1, 2010

- The LCFS is part of a larger strategic effort to reduce greenhouse gas emissions. The sooner we reduce emissions, the more cost-effective mitigation efforts will be and the more likely we are to reduce the risk of catastrophic climate impacts. Oregon can serve as an example to the rest of the country and should be commended for its leadership on the LCFS. Policies that reduce emissions help safeguard Oregon’s economy, health, and environmental well-being. Every effort should be made to maintain the environmental integrity of this program.

**General Comments**

**November 3, 2009 Advisory Committee Meeting**

- Oregon needs to go slowly and consider all of the possible effects before adopting a program that could have such major consequences.
- Oregon should look to Washington state rather than California in considering a LCFS, since most of Oregon’s fuel comes from Washington refineries and the effects of a Washington state LCFS on refinery operations in that state will have effects here.
- California is spending hundreds of millions supporting its LCFS program, compared to a few staff positions in Oregon.
- California performed a life cycle analysis of fuels such as ethanol, a position which commenter recalls some Oregon staff seeming to disagree with.
- Committee must consider costs of the program, and of emissions reductions in general.
- Concern that the committee consider its obligation to look farther into the future, considering the impact of avoiding hard questions now;
- A lot of opportunities for wealth creation will accompany the switch to lower carbon fuels.
- The committee should look for opportunities, especially for rural Oregon.
- Committee must consider impacts of new policies on jobs and the existing electric grid.
- Implementation issues need attention, e.g. giving markets time to respond, keeping current economic conditions in mind, consider micro-economic impacts along with macro-economic impacts.

**January 27, 2010 Advisory Committee Meeting**

- A committee member commented that the LCFS is not focused on discouraging the use of fuel through conservation, nor on reducing vehicle emissions. Rather the LCFS is focused solely on lifecycle emissions from fuels. Another committee member noted that efforts are underway by groups in the state to address those other issues, and suggested that the advisory committee voice support for efforts to
reduce vehicle emissions and vehicle miles travelled. Chair Reeve suggested that the decisions about which greenhouse gas reduction programs to pursue belong to the Legislature, and that the committee’s focus should be making recommendations for a state LCFS. However, he supports giving individual committee members the opportunity to include comments about policy issues and other concerns in the committee’s final report to the Environmental Quality Commission.

**Summary of written comments from advisory committee member or alternate November 30, 2010**

- The committee process was well-run and provided an excellent vehicle for raising and airing issues about compliance and implementation. The LCFS is a powerful tool for reaching greenhouse gas emissions goals and will work well in Oregon.
- DEQ did an excellent job managing and staffing the committee, and the implementation of the LCFS will certainly benefit from the hard work of all those involved.

**Summary of written comments from advisory committee member or alternate December 1, 2010**

- We would like to commend the Department of Environmental Quality (DEQ) for a well-run process that has given all stakeholders—and especially impacted sectors—ample opportunity to provide input on all facets of the program. At every step of the process, DEQ has evaluated how to make the LCFS administratively straightforward for both industry and the agency. DEQ has been thoughtful in preparation of materials and extended the timeframe for the Advisory Committee to run through 2010.
- DEQ prepared a comprehensive and streamlined draft report for review. The Low-Carbon Fuel Standard is an important policy for Oregon’s long-term environmental and economic health. We look forward to continued participation in the process to develop Oregon’s LCFS and its adoption by the Environmental Quality Commission.
- We feel that when implemented the LCFS will be a productive policy too to both spur fuel innovation, economic development and lower carbon emissions in the transportation sector.
- We feel that Staff led a very professional open and effective stakeholder process.
- Global warming is the most pressing global issue facing this generation. At every level we will need a systematic and strategic approach to meet this challenge.
- Transportation represents roughly one-third of America’s and Oregon’s global warming pollution. In order to reducing pollution from the transportation sector, we will need to build move livable communities and reduce the number of miles traveled by vehicle, make cars and trucks go farther on a gallon of gasoline, and use fuels that emit less global warming pollution.
- In 2009, the Oregon legislature adopted and the governor signed House Bill 2186 which provided the authority to the Oregon Department of Environmental Quality ("DEQ") to create a low carbon fuel standard ("LCFS"). The LCFS requires fuels to be 10 percent less carbon intensive by 2020 in comparison to 2010 levels. In drafting the low carbon fuel standard, the Oregon Department of Environmental Quality sought and gained an enormous level of input from key stakeholders. Given this high level of input, Environment Oregon strongly supports the Environmental Quality Commission adopting the LCFS in 2011.
- The work of DEQ’s staff has been tremendous to get us to this stage. The LCFS will be an integral component in reducing global warming pollution from the transportation sector and meeting Oregon’s climate challenge. In addition, as a market-based regulatory approach, it effectively internalizes the...
environmental and social costs of global warming while encouraging the growth of Oregon businesses that specialize in producing and distributing homegrown clean fuels and cars.

- The Department of Environmental Quality is to be commended for its professionalism, competence and willingness to work with a wide range of interests at the table that composed the LCFS Advisory Committee this past year.

- Oregon has taken a leadership role in addressing the opportunity for low carbon fuels in the state. Significant work by DEQ has gone into crafting this draft report. Overall, ZeaChem believes the recommendations made by DEQ in the report will encourage the production and consumption of advanced biofuels in Oregon with associated investment and job creation benefits.

- The blending of ethanol into the gasoline fuel pool is regulated at both the state and federal levels. Current blending for the general vehicle fleet is limited to 10% ethanol by the U.S. EPA as well as by the state of Oregon. As the draft report and appendices correctly recognize, the EIO blend wall is projected to be reached in 2013, meaning that no more ethanol will be allowed to be blended into gasoline. This limit creates a significant barrier for the entry of advanced, cellulosic ethanol into the market.

- Recommendation: In order for Oregon to equally promote the production of all available low carbon fuels, including ethanol, the EIO blending limit needs to be raised. The U.S. EPA is making progress to raise the blend level to 15% (E15). Because Oregon has separate policies in place limiting ethanol blending to 10% (see: ORS 646.913, ORS 646.957, and OAR 603-027-0420) ZeaChem encourages DEQ to include in its draft report a specific recommendation to amend state policies regarding ethanol blending. Such a modification will align Oregon with federal policy and encourage the production of advanced, cellulosic ethanol in the state.

- The Department of Environmental Quality is to be commended for its professionalism, competence and willingness to work with a wide range of interests at the table that composed the LCFS Advisory Committee this past year.

**Public Comment at Advisory Committee Meetings**

- **November 3, 2009 Advisory Committee Meeting**

  - **Dwight Stevenson of Tesoro:** Expressed concern about the complexity of a LCFS program. He also noted the potential for unintended consequences, citing the example of California’s reformulated gasoline requirement that initially led to the use of methyl tertiary butyl ether or MTBE. MTBE was later found to cause water contamination when leaked from underground tanks. In the third phase of the reformulated gasoline program, the reformulation caused increased permeation [i.e., more fuel evaporating through fuel lines and contributing to smog].

- **December 3, 2009 Advisory Committee Meeting**

  - **Ralph Moran, BP America:** BP continues to think it’s important for the advisory committee to discuss the purpose of the LCFS and what the alternatives are, which would be consistent with the process going on in Washington and he thinks also consistent with HB 2186. He thinks the committee needs to discuss whether the objective is GHG reductions or fuel innovations. If a national carbon reduction program is enacted, the incremental GHG reduction impact of the LCFS will be zero. BP worked with CARB in putting together the California LCFS, and believes the advisory committee has heard only one side of the
story from CARB, but needs to hear other sides to the story. BP has big concerns with California’s LCFS design – some of those design flaws could be fixed, and others are inherent to the LCFS. They think it’s important that the committee hear a presentation from BP, with opportunity for back-and-forth between the presenter and the committee.

- **Dwight Stevenson, Tesoro:** He thinks it would be helpful to draw a diagram of what the committee is envisioning, for instance where in the process a credit is generated, to make it easier to understand. Other indirect emissions that haven’t been considered by CARB thus far are those due to increased farming intensity, using more water and fertilizer, which could occur due to increased demand for biofuel crops. CARB’s expert workgroup will look at this issue. The committee should consider whether to set separate baselines for gasoline and diesel, since diesel has lower carbon intensity and increased use of diesel could contribute to GHG reductions. The economic analysis needs to consider the technological feasibility of producing the fuels that will be necessary – he didn’t see plans for an adequate technological analysis in the presentation this morning. If alternative fuels aren’t currently being produced, perhaps they are not economically competitive, contrary to CARB’s economic analysis. CARB assumed a cost for ethanol in their economic analysis, but this was not based upon an engineering analysis, and the assumptions are overly optimistic.

**April 15, 2010 Advisory Committee Meeting**

- **Angus Duncan, Global Warming Commission:** With regard to carbon content of those miles that are going to driven by electric vehicles, even if it is plugged in at night and even if you did not assume that it was being met by the marginal gas instead of the coal. At some level we have to assume that there is going to be substantial electric vehicle market penetration and therefore needed additional base load. But pretty much every analysis that I have seen, government and interest group, has been pretty clear that if you plug your electric vehicle into a wall socket in your garage and it is fed with electricity from a pulverized coal plant, that you are still on a carbon basis but it is substantially less carbon intensive when you get in that car and drive it. Yes, you are technically driving coal generated electricity, but you are displacing another fossil fuel, another hydrocarbon, gasoline, and the efficiencies of a single large coal plant are so much greater even after allowing loses from transmitting from Wyoming to Portland, Oregon and putting it into an electric vehicle that there is a significant carbon savings to doing that, assuming the worst coal based resource case. And if we assume that increasingly as coal plants are retired and are replaced by base load gas plants that carbon benefit increases proportionately, so electric vehicles are a very significant carbon reduction mechanism even given the existing resource configuration in the country, let alone in the Pacific Northwest. Secondly this question of how intermittent resources interact with the system. Because there is a tendency to think one dimensionally, that if you put a wind project on the system and you have to have electricity when someone flicks the light that you need a dispatchable resource, gas or coal, immediately behind it and you have to match it megawatt for megawatt. If you really push it to the extreme and that back-up megawatt needs to either be running or it can be ramped up in seconds because the wind could die off in seconds. As a practical matter, that is just not how the system works. The system calculates its reserve obligations while looking at a whole range of resources, not just any one source and it also looks at the diversity among the resources. It looks at the consequences if one wind trimming was banned, which is 1-400 megawatt coal plant or 1-1,100 megawatt nuclear plant on an un-scheduled outage. It has to calculate how much reserve is needed for a variety of different scenarios not just one involving wind and wind dropping off almost instantaneously.

Even if we were looking at that, we would also have to look at the regional resource diversity underlying that wind resource. Because you can have the wind dying off in a project over here and the wind coming
up on a project over there, you can decide if you are going to look at it on a seasonal basis, or an hourly basis or a minute-to-minute basis. We get different calculations in each one of those cases and I could really belabor this and get tedious, but I promise you I will not. The only other point that I wanted to make was that when we started the project that I am still involved in called The Regional Wind Integration Project, which is chaired by Bonneville and the power council. Pretty much all the utilities in the region participate in that and a few riff-raff members like me. We look at a number of different things. We looked at what the existing system would accommodate by way of new penetration, what kind of tweaks you could do to the systems to up that before you had to add any new resources whatsoever. In addition, then you looked at what the range of new resources might be, storage and demand side and generation that could add to the system flexibility. Long story short, I think Bonneville and the utilities were pretty nervous about anything assuming 10% wind penetration. The Bonneville system is already up between 15-20% and they are operating without having to add any new flexibility. They have tweaked the system. They have expanded some of the balance in authority in the connections that are compared to that. There is at least one study from the upper Midwest that suggests that you could get as much as 30-35% wind penetration or wind and solar intermittent penetration before you had to start adding new reserve capacity. So there is a lot of flexibility still in the system and frankly, electric vehicles testing that system make me a lot less nervous that the potential that we will be shutting down a very substantial amount of the coal fuel in the next 20 years. One of the resources that we looked at in that integration project, and it is in the report, that is a potential significant contributor to adding flexibility into the system is plug-in electric hybrid vehicles. So, while they may test the demands and capacity back to the system, because of their storage capability, they may also add significant capacity to the system. And they may add at the wind, similar to that in Wyoming where it has to come over through wires, but right here in downtown Portland. So it’s a more complicated subject than obviously you have time to get into here, but I think issues of electrical system capacity being able to accommodate even George’s most ambitious projections is an issue that we have to deal with, but it is an eminently manageable issue at this stage.

June 23, 2010 Advisory Committee Meeting

- **Todd Campbell from Clean Energy:** Regarding the horizon that you are considering for the overall low carbon fuel standard. Ideally we would love to see a 2020 timeframe, because as soon as the program starts we can start expanding our penetration and developing infrastructure to support the low carbon fuel standard, as well start generating credits, which we think are a wholly valuable commodity down the road. I also wanted to express that the further we push out the horizon delays really being able to invest more heavily in ultra low carbon fuel, such as biomethane in the region, because we actually do account, to some degree, for credit generation of what would be derived from the program to be able to bring ultra low carbon fuels, like biomethane into the market. We certainly would be supportive of a 2020 or a 2022 time frame, but we would be happier with a 2020, because we would like to be able to expand our growth sooner rather than later.

- **Angus Duncan, Chairman of the Oregon Global Warming Commission:** On the question of a single carbon intensity value for electricity versus one that actually reflects the underlying resources that are delivering the carbon; I understand all of the reasons why you all have headed down the path that you have, but I think for consumer information value and transparency a consumer who is paying a lot of money for a plug-in hybrid or an electric vehicle is entitled to know what the carbon value is of his or her action is. Given a single carbon intensity value just peanut butter’s that value. So it both has a market integrity affect and a disincentive to folks to move faster to acquire these vehicles. On the question of 2022, 2024 and 2020 compliance period horizon, at some level I’m relatively indifferent as to what
number you pick as long as there is a way to characterize the outcome at 2020. So if the analysis can do a look back as well as a look forward, there is no great magic to the state’s 2020 goal of emissions reduction, but there is a lot of policy significance to it. And if we are asking other sectors to try to meet that 2020 goal or aim toward that 2020 goal, I think it is important that the vehicle sector and the fuel sector try to do so as well. Or at least to come up with a value that we are aiming at and a value that we achieve in 2020. So I think it is more a calculation issue than a compliance horizon period. But I would encourage us not to diminish the importance of that 2020 note. Thanks very much.

August 5, 2010 Advisory Committee Meeting

- **Todd Campbell, Clean Energy:** For a long time we’ve been overly dependent on one fuel source and have seen price hikes as a result. A low carbon fuel strategy is not only about Greenhouse gas emission reduction, but also about fuel diversity. Historically, trend of oil compared to natural gas transportation fueling, BTU price to price per barrel (of oil) has been about six to eight times, today it is about twenty times (in terms of price). There are opportunities where low carbon fuels make sense in this market place, and that should be considered as (LCFS) policy moves forward. It is dangerous, as was suggested earlier, to look to the low carbon fuel industry to make sure the LCFS program is successful. It is more important to make sure the regulated parties that are producing fuel are invested in this program. As a private company investing (low carbon fuels) capital in Oregon, we are concerned about deferrals that are applied industry-wide, and the potential for (low carbon fuel deficit) forgiveness. We want companies to invest in low carbon fuels, and believe there will be multiple players. Consumers will recognize choice in the market and (a diversity of low carbon fuels) will drive competition, resulting in lower fuel prices. We are surprised by the carbon intensity assumptions of natural gas extraction from shale and the impacts on indirect land use associated with the ILUC impacts table from the CARB workgroup presented today. (Clean Energy) has not seen this table prior to today, as it was generated in a closed meeting, and ask the committee to reserve judgment on the information in the table, due to the proprietary nature of the processes that were analyzed.

November 16, 2010 Advisory Committee Meeting

- **Mary Solecki, Environmental Entrepreneurs:** Hello, my name is Mary Solecki with Environmental Entrepreneurs, an organization that works with the NRDC as the independent business voice and I am advocating on their behalf for the implementation of a Low Carbon Fuels Standard across the country. I’ve been following these meetings via phone, and wanted to comment on behalf of the biofuels producers that I’ve been working with in Oregon, I urge you to incorporate the indirect land use change component into the program. The biggest lesson that we’ve learned from California is to strictly adhere to the compliance schedule, as it will be a predictable path of market opportunity for investors to follow.
Appendix B: Lifecycle Analysis

Oregon Low Carbon Fuel Standards Report

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11-AQ-004b
1/25/2011
Sue Langston
1. Introduction

A Lifecycle Analysis of fuel is an evaluation of environmental impact associated with its production and combustion. Figure 1 is a schematic representation of Lifecycle Analysis, also known as a fuel pathway.

The Well-to-Tank portion of Lifecycle Analysis of a fuel pathway involves production, storage, and transport of fuel.

The Tank-To-Wheel portion of Lifecycle Analysis of a fuel pathway takes into account combustion of fuel in a motor vehicle. Well-To-Wheel is a combination of Well-to-Tank and Tank-To-Wheel, and captures energy inputs and greenhouse gas emissions that result from production, distribution, storage and transportation of a fuel.

![Fuel Lifecycle Analysis chain of events](image)

**Figure 1:** Fuel Lifecycle Analysis chain of events

We calculated energy use and greenhouse gas (GHG) emissions using GREET (Green House gases, Regulated Emissions, and Energy in Transportation) – a life cycle analysis model developed and maintained by Argonne National Laboratory. GREET is designed to calculate the energy use and greenhouse gas (GHG) emissions associated with production and use of fuels. The model version GREET 1.8c was modified by TIAx and DEQ to reflect Oregon specific conditions.

The carbon Intensity of a given fuel represents grams of carbon dioxide released per one megajoule of energy produced during all stages of fuel production, storage, transportation, and use. The carbon intensity values are adjusted to reflect co-products, indirect effects, and energy economy ratios where applicable.
2. Oregon Petroleum Pathways Key Inputs and Assumptions

Oregon petroleum pathways overview is shown in Figure 2.

In calculating the carbon intensities petroleum fuels used in Oregon, DEQ used a combination of GREET defaults and Oregon specific inputs and assumptions.

For the purposes of this analysis, DEQ assumed that about 90% of Oregon’s petroleum is processed at Washington refineries and transported along the Olympic pipeline and by ocean tanker to Portland. Some of it is further transported by barge to Pasco. The remaining 10% of Oregon petroleum fuels is refined in Utah and transported along the Chevron pipeline. Figure 3 is a map from ICF International showing the distribution of Oregon’s refined petroleum.
Sources of crude oil in Washington and Utah refineries are shown in Figures 4 and 5.
Based on the Canada National Energy Board Report (2009 Exports to PADD V), out of the 17% of Canadian crude used at Washington refineries, 51% is conventionally extracted and 49% is extracted from oil sands. The Canada National Energy Board Report 2009 (Exports to Southern PADD IV) estimates that 25% of Utah’s crude is conventional while 75% is extracted from oil sands.

We used GREET default consumption values for both conventional and oil sands energy. These inputs include process efficiency, process fuel shares, and flaring and venting volumes of natural gas in the recovery process.

Process efficiency is a function of crude recovery energy consumption and refining energy consumption related to the unit of fuel energy produced. Process fuel shares distribute the total energy consumed in the process among a variety of fuel types, e.g. 62% of fuel consumed to recover crude is natural gas. GREET default values are shown in Table 1.
DEQ has adjusted crude and refined fuel transport distances and modes, cargo ship payload values, and electricity mixes. Transportation distances and modes used in Oregon GREET reflect DEQ assumptions that 100% of the crude transported to Washington is by pipeline (646 miles); sixty five percent of gasoline blend stock is then transported to Portland by Olympic pipeline (217 miles) and 35% by ocean tanker (329 miles). Twenty five percent of the gasoline transported to Portland, is further transported from Portland to Pasco by barge (179 miles).

Crude extraction electricity mixes for crude extraction from Oil Sands are as follows: Alberta mix used for oil sands recovery; a weighted average of Alberta, Alaska, Saudi Arabia, Angola, and Argentina is used for conventional crudes. Cargo ship crude oil payload values used are 25,000 deadweight ton limit entering port of Seattle and 80,000 deadweight ton limit for Panama Canal.

For electricity consumption in Washington, the fuel mix from the 2007 WA Department of Commerce Fuel Mix Disclosure Reports were used; for electricity consumption in Utah, the 2007 Utah Geological Survey fuel mix was used. Washington and Utah electricity source mixes are shown in Figure 6.

---

**Table 1: Energy consumption GREET default inputs**

<table>
<thead>
<tr>
<th></th>
<th>Conventional Crude Recovery</th>
<th>Oil Sands Mining Recovery</th>
<th>Oil Sands In-Situ Recovery</th>
<th>Gasoline Blendstock Refining</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Process Efficiency</strong></td>
<td>98%</td>
<td>94.8%</td>
<td>84.3%</td>
<td>87.7%</td>
</tr>
<tr>
<td><strong>Process Fuel Shares:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Crude</td>
<td>1%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residual Oil</td>
<td>1%</td>
<td></td>
<td></td>
<td>3%</td>
</tr>
<tr>
<td>Diesel</td>
<td>15%</td>
<td>1%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>62%</td>
<td>82%</td>
<td>97%</td>
<td>30%</td>
</tr>
<tr>
<td>Electricity</td>
<td>19%</td>
<td>17%</td>
<td>3%</td>
<td>4%</td>
</tr>
<tr>
<td>Coal</td>
<td></td>
<td></td>
<td></td>
<td>13%</td>
</tr>
<tr>
<td>Refinery Gas</td>
<td></td>
<td></td>
<td></td>
<td>50%</td>
</tr>
</tbody>
</table>
Vehicle combustion emissions are calculated based on the assumption that all CO will convert to CO2 in the atmosphere. Environmental Protection Agency Renewable Fuel Standard (RFS2) Regulatory Impact Analysis carbon intensity values for vehicle CH4 and N2O emissions were added to the final diesel and gasoline carbon intensities.

Oregon gasoline and diesel carbon intensity are presented in Figures 7 and 8.
3. Oregon Ethanol Pathways Key Inputs and Assumptions

Oregon ethanol pathways overview is shown in Figure 9.

![Figure 9: Oregon ethanol pathways overview.](image-url)

Inputs for ethanol pathways differ based on feedstock (corn, farmed trees, forest residue, etc.). Farming and collection energy use assumptions are split by fuel type and by combustion devise. Fertilizer, pesticide, and herbicide applications differ by type, production energy consumption, transport modes and distances and percentage of Nitrogen in fertilizer emitted as N2O. Crop yields; feedstock transport and distances; and ethanol production assumptions such as process efficiency by fuel type and combustion devise, process yields, co-product credits, and fuel transport and distances are also taken into account.

DEQ staff has calculated carbon intensities for seven ethanol pathways: Ethanol produced in the Midwest from Midwest grown corn; Ethanol produced in the Northwest from Midwest grown corn; Ethanol produced in the Northwest from Northwest farmed trees; Ethanol produced from wheat straw; Ethanol produced from forest residue; Ethanol produced from mill waste, and Ethanol produced from Brazilian sugar cane.
a) Ethanol produced in the Midwest from Midwest Grown Corn

DEQ used GREET defaults for farming energy (12,635 BTU/bushel), corn yield (158 bushels/acre), and fertilizer and pesticide production and application rates. Corn is assumed to be transported to storage 50 miles by truck. Ethanol production process was assumed 87.5% dry milling and 12.5% wet milling. The dry mill process consumes 36,000 BTU energy per gallon of fuel produced. Process fuel shares are 80% natural gas, 20% coal. The ethanol yield from the dry milling process is 2.72 gallons per bushels of corn. The wet mill process consumes 45,950 BTU per gallon with a process fuel mix of 60% natural gas and 40% coal. The ethanol yield from the wet milling process is 2.62 gallons per bushels of corn.

An energy and emission credit is given to the ethanol pathway equal to the energy and emissions of the product that is being displaced or substituted (co-products). Dry milling produces distiller’s grains and solubles (DGS), wet milling produces corn gluten meal (CGM) and corn gluten feed (CGF). The US Average electricity mix shown in figure 10 is used in this pathway. Transportation distance is adjusted to 1850 rail miles to Portland and 71 truck miles to refueling stations.

![Figure 10: US average electricity mix](image)

b) Ethanol produced in the Northwest from Midwest Grown Corn

GREET defaults were used for farming inputs. Corn transport from Minnesota, South Dakota, and North Dakota to the Pacific Ethanol plant in Oregon was assumed to be 1350 rail miles. Pacific Ethanol information was used for ethanol production inputs. The process is a 100% dry mill with 100% natural gas as process fuel. Ethanol transportation from the plant to Portland is 140 barge miles, and from the barge terminal, an average of 71 miles to fueling stations. Oregon 2007 electricity source mix shown in Figure 11 was used in this pathway. GREET default co-product substitution values are used for energy and emissions credit.
c) Ethanol produced from Northwest Farmed Trees

ZeaChem's 250,000 gallon per year demonstration scale cellulosic biorefinery is currently under construction in Boardman, Oregon. This pathway is based on ZeaChem’s mature technology.

Poplar trees will be used as a feedstock and will be supplied by the GreenWood Tree Farm nearby. ZeaChem specific ethanol production parameters such as chemical use, ethanol yield, process fuels shares, and transportation distances and modes were utilized in GREET calculations for this pathway.

Poplar farming assumptions:

- Farming energy consumption: 637,428 BTU/dry ton;
- Farming energy fuel shares: diesel 33.5%, electricity 66.5%);
- Nitrogen fertilizer: 1,633.17 gram/dry ton;
- P₂O₅ fertilizer 453.59 gram/dry ton;
- Herbicides: 141.86 gram/dry ton;
- Insecticides: 11.34 gram/dry ton;

Ethanol production assumptions:

- Ethanol production process: fermentation;
- Ethanol yield: 135 gal/bone dry tons (BDT);
- Feedstock transportation: 30 miles;
- Fuel Distribution: 140 barge miles;
The default assumption in GREET is that electricity generated from combustion of biomass exceeds what is required for the cellulosic ethanol production process. We assumed that the ZeaChem process would be net zero, therefore, the OR-GREET inputs reflects that no electricity will be imported or exported from the grid for ethanol production process needs.

d) Ethanol produced from Wheat Straw

This pathway is based on the corn stover GREET pathway with values of many assumptions modified.

Farming assumptions:


- Increased fertilizer use is assumed to make up for straw removal, assumed straw nutrient values are 11lb N/ton, 3lb P$_2$O$_5$/ton, 15 lb K$_2$O/ton from a May 2007 report “Nutrient Value of Wheat Straw”, Ontario Ministry of Agriculture, Food and Rural Affairs.

- Credit is assumed for avoided N$_2$O emissions from straw.

- Wheat straw collections energy of 205, 657 BTU/dry ton of straw removed is based on hay swather, round baler, and round bale mover diesel consumption of 1.62 gal/acre reported in June 2009 University of Minnesota paper “Machinery Cost Estimates” by W. Lazarus.

- Wheat straw transport of 120 truck miles is assumed based on a potential wheat growing area in Southeast Washington and either Pacific Ethanol or ZeaChem biorefinery.

- Ethanol production assumptions include fermentation as fuel production process, ethanol yield of 65 gal/dry ton, feedstock handling energy of 180 BTU/gal (GREET default).

- No electricity credit is given, 60% of biomass is assumed to be processed to ethanol and 40% used as process fuel. Ethanol transport is assumed 140 barge miles from Boardman to Portland.

e) Ethanol produced from Forest Residue

Forest residue collection energy GREET default of 590,067 BTU/dry ton is used in this pathway. Forest residue is assumed to be transported 75 truck miles to a hypothetical plant near Ellensburg, Washington.

- Gasification is assumed as the ethanol production process and GREET defaults for gasification are used for process fuel and ethanol yield.
f) **Ethanol produced from Mill Waste**

Since mill waste is a by-product of the lumber industry, no collection energy was calculated for this pathway, using an average transport distance of 75 miles from the mill to the fuel plant. GREET default feedstock handling energy of 180 BTU/gas, process fuels share and allocation to byproducts were used in this pathway. Ethanol transport of 100 truck miles to blending terminals and from there, an average of 71 miles to refueling stations is assumed.

g) **Sugarcane Ethanol**

GREET default farming, feedstock transport, and ethanol production inputs are used for this pathway. Ethanol transport is 500 miles to Marine terminals (50% rail, 50% pipeline), 9060 nautical miles from SE Brazil port to Portland and 71 truck miles to refueling stations.

Oregon Ethanol carbon intensity values are shown in Figure 12.

![Figure 12: Oregon Ethanol carbon intensity values. ILUC emissions are not accounted for.](image-url)
4. Oregon Biodiesel Pathways Key Inputs and Assumptions

Oregon biodiesel pathways overview is shown in Figure 13.

![Figure 13: Oregon biodiesel pathways overview](image)

We have calculated carbon intensities for five biodiesel pathways: Midwest soybeans biodiesel; Northwest Canola; Yellow grease; Tallow, and Midwest Soybeans renewable diesel.

**a) Midwest Soybean Biodiesel Pathway**

Midwest average soybean production, GREET default farming, and soybean transport assumptions are used in this pathway. Soy oil extraction and biodiesel production assumptions include data from EPA RFS2, and GHGenius, a model for lifecycle assessment of transportation fuels, with emphasis on Canada. Biodiesel transport is adjusted to 40 truck miles to rail terminals, 1,850 rail miles to Portland, and from there, an average of 71 miles to refueling stations.
b) **Northwest Canola Biodiesels Pathway**

The main assumption for this pathway is that canola is farmed and processed to biodiesel in Eastern Washington and transported to Portland, Oregon. Farming assumptions include energy consumption of 27,149 BTU/bu (GHGenius). Fertilizer and pesticide use is based on 2005 GHGenius farm survey data. Based on the GEGenius 2005 update, oil yield is assumed to be 0.41 lb oil/lb seed; extraction energy is 1,053 BTU per gallon of oil; process fuels share 87% NG, and 13% electricity. Mass basis allocation of energy between canola oil (37%) and meal (63%) is based on CARB’s approach. Biodiesel production assumptions: process fuel use is assumed to be 1840 BTU per pound which is an average of EPA RFS2 and GHGenius values for natural gas, electricity, and methanol. Biodiesel yield is one pound of biodiesel per pound of canola oil based on EPA RFS2 and 0.1lb of glycerin per pound of biodiesel based on CARB. Energy basis allocation of process energy between glycerin (5%) and biodiesel (95%) is assumed. Biodiesel transport is assumed to be 150 rail miles, 150 track miles to terminal and 71 truck miles to refueling stations.

c) **Yellow Grease Biodiesel**

This pathway is based on CARB Used Cooking Oil pathway. SeQuential-Pacific Biodiesel plant in Salem, Oregon utilizes regionally sourced feedstock to produce over 17 million gallons of biodiesel per year. Energy consumption of 140 BTU/lb with fuel shares of 80% NG and 20% electricity is assumed in this pathway. Oregon 2007 average electricity mix is used. The production process assumptions are based on the combination of GREET defaults and SeQuential provided information.

d) **Tallow Biodiesel**

Tallow is oil produced in meat rendering plants; meat is crushed and cooked to liquefy the fat; tallow is drained and screw pressed from the solids and filtered. There is no current tallow biodiesel production in Oregon. This process is based on CARB Tallow and Used Cooking Oil pathways. A combination of GREET defaults, CARB data, and SeQuential information are used in assumptions for this pathway.

e) **Northwest Renewable Diesel produced from Midwest Soybeans**

The main assumption of this pathway is the Midwest soy oil is processed to biodiesel at a Northwest refinery. GREET Renewable Diesel II (RDII) pathway is used and an operational plant in Arlington, Washington is assumed based on the June 2008 Washington State University report “Biofuel Development in Washington”. An 8 Mgal/year facility in Arlington is described as shifting its standard biodiesel operation to renewable diesel. The renewable diesel production process co-produces propane.

Farming assumptions and soybean transport are GREET defaults; 2,000 rail miles soy oil transport to Arlington, WA is assumed. Renewable diesel production assumptions are based on a
combination of CARB, EPA, and GHGenius updates. Renewable diesel transport to Portland assumes 190 track miles from Arlington to Portland and 71 miles to refueling stations. Figure 14 represents OR biodiesel carbon intensities.

![Figure 14: Oregon biodiesel carbon intensities](image)

### 5. Oregon Electricity Pathway

Oregon 2007 statewide weighted average provided by ODOE and shown in Figure 11 was used in this pathway. Electricity pathways carbon intensity is comprised of 8.88 gCO2e/MJ from feedstock recovery and transport to the power plant and 146.10 gCO2e/MJ from electricity production at the power plant, resulting in a carbon intensity of 154.98 gCO2e/MJ. This value is then adjusted with an energy economy ratio (EER) to account for the difference in energy use per electric vehicle mile compared to that of a conventional light-duty or heavy-duty vehicle. The EER applied depends on the year and whether the electric vehicle substitutes for a light-duty or heavy-duty vehicle. For the final carbon intensities, please see the “Fuel Carbon Intensity Lookup Table” chapter in the report. For a description of EERs please see “Calculating Carbon Intensities for Oregon’s Fuels” chapter in the report.

### 6. Compressed Natural Gas (CNG) Pathway

This pathway represents pipeline natural gas compressed to CNG at the refueling station. GREET default recovery, processing, pipeline transmission, and natural gas properties assumptions are used. CARB method and values for transmission leakage and an assumption that all station compressors are electric drive are utilized. Oregon 2007 average mix electricity is used in this pathway. Compressor efficiency is assumed to be 98% as per CARB. CNG pathway’s carbon intensity amounts to 8.2 gCO2e/MJ from recovery, processing, and transport; 3.16 gCO2e/MJ from compression, and 58.8 gCO2e/MJ from vehicle combustion to a total CI of 70.2 gCO2e/MJ for CNG pathway. This value is then adjusted with an energy economy ratio
(EER) to account for the difference in energy use per CNG vehicle mile compared to that of a conventional light-duty or heavy-duty vehicle. The EER applied depends on the year and whether the CNG vehicle substitutes for a light-duty or heavy-duty vehicle. For the final carbon intensities, please see the “Fuel Carbon Intensity Lookup Table” chapter in the report. For a description of EERs please see “Calculating Carbon Intensities for Oregon’s Fuels” chapter in the report.

7. Overview of Oregon Carbon Intensities

Carbon Intensity Values of all Oregon pathways is summarized in Table 2. These do not include indirect land use change, and have not been adjusted with energy economy rations.

Table 2: Summary of OR Carbon Intensity Values

<table>
<thead>
<tr>
<th>Pathway</th>
<th>Wheel to Tank (WTT), g CO2e/MJ</th>
<th>Tank-to-Wheel, g CO2e/MJ</th>
<th>Total Direct, g CO2e/MJ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Feedstock &amp; Transport</td>
<td>Production T&amp;D</td>
<td>WTT Total</td>
</tr>
<tr>
<td>Gasoline Blendstock</td>
<td>6.80</td>
<td>11.23</td>
<td>18.03</td>
</tr>
<tr>
<td>Ultra Low Sulfur Diesel</td>
<td>6.79</td>
<td>9.71</td>
<td>16.51</td>
</tr>
<tr>
<td>Ethanol</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• MW Corn Average</td>
<td>21.45</td>
<td>42.54</td>
<td>63.99</td>
</tr>
<tr>
<td>• NW production, MW Corn</td>
<td>18.56</td>
<td>34.39</td>
<td>52.95</td>
</tr>
<tr>
<td>• Farmed Trees</td>
<td>11.03</td>
<td>3.68</td>
<td>14.71</td>
</tr>
<tr>
<td>• Wheat Straw</td>
<td>15.29</td>
<td>4.78</td>
<td>20.07</td>
</tr>
<tr>
<td>• Forest Residue</td>
<td>11.38</td>
<td>8.28</td>
<td>19.66</td>
</tr>
<tr>
<td>• Mill Waste</td>
<td>3.68</td>
<td>7.80</td>
<td>11.48</td>
</tr>
<tr>
<td>• Brazil Sugarcane</td>
<td>20.00</td>
<td>5.61</td>
<td>25.61</td>
</tr>
<tr>
<td>Biodiesel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• MW Soybeans</td>
<td>6.00</td>
<td>10.29</td>
<td>16.29</td>
</tr>
<tr>
<td>• NW Canola</td>
<td>15.74</td>
<td>7.87</td>
<td>23.61</td>
</tr>
<tr>
<td>• Yellow Grease Average</td>
<td>0.83</td>
<td>5.75</td>
<td>6.58</td>
</tr>
<tr>
<td>• Tallow Average</td>
<td>7.40</td>
<td>5.75</td>
<td>13.15</td>
</tr>
<tr>
<td>Renewable Diesel. NW Production, MW soy oil</td>
<td>5.80</td>
<td>15.20</td>
<td>21.00</td>
</tr>
<tr>
<td>Electricity, 2007 OR avg. mix</td>
<td>8.88</td>
<td>146.10</td>
<td>154.98</td>
</tr>
<tr>
<td>CNG, pipeline NG</td>
<td>8.24</td>
<td>3.16</td>
<td>12.59</td>
</tr>
</tbody>
</table>

¹ No EER has been applied to the carbon intensity value. For the final carbon intensities, please see the “Fuel Carbon Intensity Lookup Table” chapter in the report.
Memorandum

Date: Oct 18, 2010
To: Oregon DEQ
JFA (Mike Lawrence, Scott Williams)
From: Jennifer Pont
Subject: LCFS Scenarios Infrastructure Costs

To support DEQ’s LCFS analysis, fuel use and vehicle population assumptions were made for business as usual (BAU) and a range of LCFS compliance scenarios using the VISION model. JFA will run the REMI model for the BAU and compliance scenarios to estimate the economic impact of a LCFS on the State of Oregon. This model documents assumed alternative fuel infrastructure cost assumptions that JFA will use to create REMI inputs. We provide cost assumptions for plug-in vehicle charging infrastructure, CNG vehicle refueling infrastructure, biofuel production and handling infrastructure. For compliance scenario and compliance run descriptions, please refer to page 14. Runs 1-4 include gasoline and gasoline substitutes, while runs 6-9 include diesel and diesel substitutes. These runs were combined into a variety of Scenarios, so that each Scenario includes a gasoline run and a diesel run. Run 5 is the One Pool Scenario E, which includes gasoline and diesel and all substitutes.

Plug-in Electric Vehicles

Plug-in electric vehicles require chargers. In the early 1990s, the Electric Power Research Institute defined three different charging levels:

- Level 1: 120 volt AC, 15/20 amp circuit (vehicle charging only to prevent overload)
- Level 2: 240 volt AC, single phase 40 amps
- Level 3: 480 volt AC, three-phase circuit fast charger

For battery electric vehicles (BEVs), a Level 2 home charging system is required. For PHEVs, the charging system depends upon battery size; larger vehicles and electric ranges have larger batteries. The amount of time required to charge a range of PHEV vehicles was estimated in a recent report by Batelle Energy Alliance¹ – the results are provided in Table 1.

<table>
<thead>
<tr>
<th>Level</th>
<th>Economy Vehicle</th>
<th>Mid-size Vehicle</th>
<th>Light Duty Truck/SUV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours</td>
<td>PHEV-10</td>
<td>PHEV-20</td>
<td>PHEV-40</td>
</tr>
<tr>
<td>Level 1</td>
<td>2.7</td>
<td>5.5</td>
<td>10.9</td>
</tr>
<tr>
<td>Level 2</td>
<td>3.6</td>
<td>7.3</td>
<td>14.5</td>
</tr>
<tr>
<td>Level 3</td>
<td>4.5</td>
<td>9.1</td>
<td>18.2</td>
</tr>
</tbody>
</table>

For the economic analysis, we assume that one Level 2 charging system is purchased for each EV sold. Based on the estimated charging times above, we further assume that a mix of Level 1 and Level 2 charging systems is purchased for each PHEV as indicated in Table 2. Table 3 provides the total number of Level 1 and Level 2 home chargers purchased between 2012 and 2022.

Table 2. Assumed Shares of Home Charger Type Purchased for Analysis Vehicles.

<table>
<thead>
<tr>
<th></th>
<th>Light Duty Auto</th>
<th>Light Duty Truck</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PHEV EV</td>
<td>PHEV EV</td>
</tr>
<tr>
<td>Level 1 Charger Share</td>
<td>50% 0%</td>
<td>10% 0%</td>
</tr>
<tr>
<td>Level 2 Charger Share</td>
<td>50% 100%</td>
<td>90% 100%</td>
</tr>
</tbody>
</table>

Table 3. Cumulative Home Charger Installations 2012-2022

<table>
<thead>
<tr>
<th>Scenario</th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHEV Auto Sales</td>
<td>16,943</td>
<td>169,570</td>
<td>48,408</td>
</tr>
<tr>
<td>PHEV Light Truck Sales</td>
<td>3,412</td>
<td>30,839</td>
<td>9,037</td>
</tr>
<tr>
<td>EV Sales</td>
<td>18,049</td>
<td>33,036</td>
<td>19,968</td>
</tr>
<tr>
<td>Number of Level 1 Chargers</td>
<td>8,813</td>
<td>87,869</td>
<td>25,108</td>
</tr>
<tr>
<td>Number of Level 2 Chargers</td>
<td>29,592</td>
<td>145,576</td>
<td>52,305</td>
</tr>
</tbody>
</table>

Estimated costs to install Level 1 and Level 2 home charging systems are provided in Table 4. The Level 1 total cost is from Battelle (2008) with sales tax backed out; it has been divided between labor materials and permit fees according to the Level 2 breakdown. The permit fee was provided by Oregon DOE. The Level 2 costs are provided by eTec and are for the Greater Seattle area but that the cost will be the same for Oregon. We also assume that the chargers are produced outside of Oregon. Table 5 provides cumulative home charger costs from 2012-2022.

Table 4. Plug-in Vehicle Home Charger Installed Costs.

<table>
<thead>
<tr>
<th></th>
<th>Level 1</th>
<th>Level 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor</td>
<td>$380</td>
<td>$962</td>
</tr>
<tr>
<td>Materials</td>
<td>$412</td>
<td>$1,041</td>
</tr>
<tr>
<td>Permit</td>
<td>$14</td>
<td>$14</td>
</tr>
<tr>
<td>Total</td>
<td>$807</td>
<td>$2,088</td>
</tr>
</tbody>
</table>

Table 5. Plug-in Vehicle Home Charger Total Costs, $Million

<table>
<thead>
<tr>
<th></th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level 1, 2012-2022</td>
<td>7.1</td>
<td>70.9</td>
<td>20.2</td>
</tr>
<tr>
<td>Level 2, 2012-2022</td>
<td>61.8</td>
<td>304.0</td>
<td>129.5</td>
</tr>
<tr>
<td>Total Home Chargers, 2012-2022</td>
<td>68.9</td>
<td>374.9</td>
<td>149.7</td>
</tr>
</tbody>
</table>
In addition to home charging, we need to consider public charging infrastructure. This consists of a number of commercial and public Level 2 charging locations (e.g. work places, shopping malls parking lots) and commercial Level 3 fast charging stations located in the major urban areas and on connecting highways.

We first estimate the number of Level 2 publicly accessible charging stations. There is a wide range of estimated need for Level 2 charging away from home. The emerging consensus seems to be fewer Level 2 charging stations than some of the earlier thinking. This is due to a number of factors including strong indications that EV ranges will increase over the next several years, decreased costs for Level 3 charging stations, and relatively short driving distances between cities in Oregon.

Under the EV Project, eTec may be installing 2050 Level 2 charging stations in Portland, Eugene, Corvalis and Salem. We further assume that there will be a small amount of public and private investment in L2 charging into the future. For our analysis, we make the assumptions indicated in Table 6.

Table 6. Level 2 Charging Station Installation Assumptions

<table>
<thead>
<tr>
<th>Scenario</th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>The EV Project</td>
<td>2050</td>
<td>2050</td>
<td>2050</td>
</tr>
<tr>
<td>Additional Locally Funded and Commercial L2 Chargers</td>
<td>2%/yr</td>
<td>5%/yr</td>
<td>2%/yr</td>
</tr>
<tr>
<td>Additional by 2022</td>
<td>449</td>
<td>574</td>
<td>449</td>
</tr>
<tr>
<td>Total by 2022</td>
<td>2,499</td>
<td>2,624</td>
<td>2,499</td>
</tr>
</tbody>
</table>

Table 7 provides estimated costs for installation of L2 publicly accessible charging stations based on the eTec Infrastructure Deployment report. Note that each station has two charging points. Finally Table 8 provides total cumulative L2 public charging costs.

Table 7. Level 2 Publicly Accessible Charging Station Cost Estimate

<table>
<thead>
<tr>
<th>Two Charger L2 Station</th>
<th>Labor</th>
<th>Materials</th>
<th>Trenching and Repairs</th>
<th>Permit</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$4,292</td>
<td>$6,287</td>
<td>$4,136</td>
<td>$85</td>
<td>$14,800</td>
</tr>
</tbody>
</table>

Table 8. Level 2 Charging Station Cumulative Costs 2012-2022

<table>
<thead>
<tr>
<th>Scenario</th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total, $Million</td>
<td>6.6</td>
<td>8.5</td>
<td>6.6</td>
</tr>
</tbody>
</table>

The Level 3 fast charging station network has two components: distributed along major highways for plug-in vehicles traveling long distances, and concentrated in city centers. Table 9 shows the estimated number of chargers distributed along major highways for the BAU and LCFS Compliance scenarios. We assume for the BAU the fast charge stations will be located every 25 miles for the Portland to Eugene I-5 corridor due to the EV project and every 40 miles from Eugene to Ashland. For the high EV case, we include charging stations along additional highways as shown in Table 9.

Next, the number of fast charge stations located within city centers is estimated as shown in Table 10. For the BAU and Scenarios 1-5 we assume that one charger will be located every 6 square miles within the major cities located along the I-5 corridor. For the high EV case, we add in cities located along the I-85, U.S. 26, and U.S. 97 corridors.

A total of 52 Level 3 stations are estimated for BAU and all scenarios except Scenario D (High EV scenario). A total of 76 Level 3 stations are estimated for Scenario D.

Table 9. Number of Distributed Fast Charge Stations

<table>
<thead>
<tr>
<th>Highway</th>
<th>Point to Point</th>
<th>Miles</th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-5</td>
<td>Portland to Eugene</td>
<td>110</td>
<td>4.4</td>
<td>4.4</td>
<td>4.4</td>
</tr>
<tr>
<td>I-5</td>
<td>Eugene to Ashland</td>
<td>178</td>
<td>4.5</td>
<td>4.5</td>
<td>4.5</td>
</tr>
<tr>
<td>I-84</td>
<td>Portland to Pendleton</td>
<td>208</td>
<td>5.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S. 26</td>
<td>Portland to Bend</td>
<td>160</td>
<td>4.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S. 97</td>
<td>Bend to Klamath Falls</td>
<td>137</td>
<td>3.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Travel Route L3</td>
<td></td>
<td>9</td>
<td>22</td>
<td>9</td>
</tr>
</tbody>
</table>

Table 10. Number of Fast Charge Stations Located in City Centers

<table>
<thead>
<tr>
<th>City</th>
<th>Square Miles</th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portland</td>
<td>134.4</td>
<td>22</td>
<td>22</td>
<td>22</td>
</tr>
<tr>
<td>Eugene</td>
<td>40.5</td>
<td>7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Salem</td>
<td>16.4</td>
<td>8</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Corvallis</td>
<td>13.8</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Medford</td>
<td>21.7</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Bend</td>
<td>32.2</td>
<td>5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Klamath Falls</td>
<td>18.7</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hood River</td>
<td>2.9</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pendleton</td>
<td>10.1</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total L3 Chargers</td>
<td>43</td>
<td>54</td>
<td>43</td>
<td></td>
</tr>
</tbody>
</table>
Table 11 provides the estimated installed cost for Level 3 Quick Charge Stations. We assume the L3 stations will be installed with public funding. Table 12 provides cumulative Level 3 charging station costs from 2012 through 2022.

Table 11. Level 3 Charging Station Cost Estimate

<table>
<thead>
<tr>
<th>Two Charger Station</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor</td>
<td>$6,452</td>
</tr>
<tr>
<td>Materials</td>
<td>$52,264</td>
</tr>
<tr>
<td>Trenching and Repairs</td>
<td>$1,379</td>
</tr>
<tr>
<td>Concrete Work</td>
<td>$1,379</td>
</tr>
<tr>
<td>Permit</td>
<td>$85</td>
</tr>
<tr>
<td>Total</td>
<td>$61,558</td>
</tr>
</tbody>
</table>

Table 12. Level 3 Charging Station Cumulative Costs 2012-2022, $MM

<table>
<thead>
<tr>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>3.20</td>
<td>4.68</td>
</tr>
</tbody>
</table>

Table 13 summarizes the overall EV Infrastructure assumptions.

Table 13. Summary of Cumulative EV Infrastructure Installments through 2023

<table>
<thead>
<tr>
<th></th>
<th>BAU and Scenarios A-C and F-H</th>
<th>Scenario D</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Home Chargers</td>
<td>38,404</td>
<td>233,444</td>
<td>77,412</td>
</tr>
<tr>
<td>Total L2 City Chargers</td>
<td>2,499</td>
<td>2,624</td>
<td>2,499</td>
</tr>
<tr>
<td>Total L3 Fast Charge Stations</td>
<td>52</td>
<td>76</td>
<td>52</td>
</tr>
<tr>
<td>Home Charger Cost</td>
<td>68.9</td>
<td>374.9</td>
<td>129.5</td>
</tr>
<tr>
<td>L2 City Charger Cost</td>
<td>6.6</td>
<td>8.5</td>
<td>6.6</td>
</tr>
<tr>
<td>L3 Fast Charge Station Cost</td>
<td>3.20</td>
<td>4.68</td>
<td>3.20</td>
</tr>
<tr>
<td>Total Cost, $Million</td>
<td>79.3</td>
<td>388.8</td>
<td>139.9</td>
</tr>
</tbody>
</table>

Compressed Natural Gas (CNG)

Table 14 provides our projected CNG vehicle populations for each compliance scenario. Table 15 provides the estimated CNG consumption in 2013 and 2023. The amount of CNG consumed in 2023 is approximately three times the 2013 level.

### Table 14. CNG Vehicle Population Forecasts for BAU and Compliance Scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Light Duty</th>
<th>Medium Duty</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2012</td>
<td>2022</td>
<td>2012</td>
</tr>
<tr>
<td>BAU</td>
<td>367</td>
<td>1,319</td>
<td>407</td>
</tr>
<tr>
<td>Runs 1-4&lt;sup&gt;a&lt;/sup&gt;</td>
<td>367</td>
<td>1,319</td>
<td>484</td>
</tr>
<tr>
<td>Runs 6-8&lt;sup&gt;b&lt;/sup&gt;</td>
<td>n/a</td>
<td>n/a</td>
<td>484</td>
</tr>
<tr>
<td>Run 9&lt;sup&gt;b&lt;/sup&gt;</td>
<td>n/a</td>
<td>n/a</td>
<td>1,570</td>
</tr>
<tr>
<td>Scenario E: One Pool</td>
<td>367</td>
<td>1,319</td>
<td>484</td>
</tr>
</tbody>
</table>

<sup>a</sup> Only includes gasoline share of MD/HD CNG use
<sup>b</sup> Only includes diesel share of MD/HD CNG use

### Table 15. Scenario CNG Consumption Forecasts, MMBtu/yr

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Light Duty</th>
<th>Medium &amp; Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2023</td>
</tr>
<tr>
<td>BAU</td>
<td>34,383</td>
<td>104,028</td>
</tr>
<tr>
<td>Runs 1-4&lt;sup&gt;a&lt;/sup&gt;</td>
<td>34,383</td>
<td>104,028</td>
</tr>
<tr>
<td>Runs 6-8&lt;sup&gt;b&lt;/sup&gt;</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Runs 6-8&lt;sup&gt;b&lt;/sup&gt;</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Scenario E: One Pool</td>
<td>34,383</td>
<td>104,031</td>
</tr>
</tbody>
</table>

<sup>a</sup> Only includes gasoline share of MD/HD CNG use
<sup>b</sup> Only includes diesel share of MD/HD CNG use

For light duty vehicles, we assume that 20% are purchased by individuals and 25% of these will be fueled at home. Therefore, 5% of light duty vehicles will have home charging equipment. The rest of the vehicles will refuel at public/private CNG stations. The installed cost of home CNG fueling equipment is estimated at $5500. This includes $4000 for equipment and $1500 for installation<sup>4</sup>. Table 16 provides our estimated cumulative home charger costs between 2013 and 2023.

### Table 16. Estimate of Total Home CNG Refueling Systems Installed by 2023

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Number of Home Refuelers</th>
<th>Total Cost</th>
<th>Labor Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>48</td>
<td>$264,000</td>
<td>$72,000</td>
</tr>
<tr>
<td>Scenarios A-D and F-H</td>
<td>48</td>
<td>$264,000</td>
<td>$72,000</td>
</tr>
<tr>
<td>Scenario E: One Pool</td>
<td>48</td>
<td>$264,000</td>
<td>$72,000</td>
</tr>
</tbody>
</table>

<sup>4</sup> BRC FuelMaker, pre Gas Equipment Systems, 909-466-6920.
New CNG refueling station sizes range from 6,000 to 12,000 gge/day with corresponding installed costs ranging from $1.5 to $2.8 million. For a station to be reasonably profitable, throughput must be a minimum of 15 percent of capacity\textsuperscript{5}.

We assume for our analysis that the average new station capacity is 8,000 gge/day, with a capacity factor of 30%. This results in annual throughput of 120,000 MMBtu/yr per station. The installed cost per station is $2.15 million. Table 17 provides our estimate of cumulative CNG station installed costs for BAU and LCFS compliance scenarios. We estimate that half of installed cost is labor.

For the LCFS diesel and one-pool compliance scenarios, we assume that various amounts of unused biogas are captured, cleaned and introduced to the pipeline. The Scenario 9 quantity is the total landfill, wastewater and dairy gases in Oregon. The installed cost for a landfill gas cleanup system has been estimated at $23.2 per annual MMBtu of capacity\textsuperscript{6}. It is assumed that these costs are equivalent to other biogas capture and cleanup systems (dairy and wastewater). Table 18 provides the biogas capture and cleanup costs for the various scenarios.

\textbf{Table 17. Estimated New CNG Refueling Station Cumulative Costs through 2023}

<table>
<thead>
<tr>
<th></th>
<th>BAU</th>
<th>Runs 1-4 \textsuperscript{a}</th>
<th>Runs 6-8 \textsuperscript{b}</th>
<th>Run 9 \textsuperscript{b}</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012 CNG Use, MMBtu/yr</td>
<td>508,823</td>
<td>48,948</td>
<td>546,257</td>
<td>1,728,228</td>
<td>595,206</td>
</tr>
<tr>
<td>2022 CNG Use, MMBtu/yr</td>
<td>2,152,140</td>
<td>169,651</td>
<td>2,389,844</td>
<td>8,040,907</td>
<td>2,560,463</td>
</tr>
<tr>
<td>CNG Use Increase, MMBtu/yr</td>
<td>1,643,316</td>
<td>120,703</td>
<td>1,843,586</td>
<td>6,312,679</td>
<td>1,965,257</td>
</tr>
<tr>
<td>New CNG Station Supply, MMBtu/yr \textsuperscript{c}</td>
<td>1,639,834</td>
<td>117,221</td>
<td>1,843,586</td>
<td>6,312,679</td>
<td>1,961,775</td>
</tr>
<tr>
<td>Estimated Number of Stations</td>
<td>14</td>
<td>1</td>
<td>15</td>
<td>53</td>
<td>16</td>
</tr>
<tr>
<td>Capital Cost, $Million</td>
<td>30.10</td>
<td>2.15</td>
<td>32.25</td>
<td>113.95</td>
<td>34.4</td>
</tr>
<tr>
<td>Labor Cost, $Million</td>
<td>15.05</td>
<td>1.08</td>
<td>16.13</td>
<td>56.98</td>
<td>17.20</td>
</tr>
</tbody>
</table>

\textsuperscript{a} Gasoline pool CNG only  
\textsuperscript{b} Diesel pool CNG only  
\textsuperscript{c} Total less home refueling volumes

\textbf{Table 18. Estimated Biogas Capture and Cleanup System Costs}

<table>
<thead>
<tr>
<th>Biogas Quantity, 2022</th>
<th>Units</th>
<th>Runs 6-8</th>
<th>Run 9</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>MMBtu/yr</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Materials</td>
<td></td>
<td>28,407,942</td>
<td>56,815,884</td>
<td>28,407,942</td>
</tr>
<tr>
<td>Labor</td>
<td></td>
<td>8,227,437</td>
<td>16,454,874</td>
<td>8,227,437</td>
</tr>
<tr>
<td>Site Prep</td>
<td></td>
<td>1,831,769</td>
<td>3,663,538</td>
<td>1,831,769</td>
</tr>
<tr>
<td>Engineering</td>
<td></td>
<td>6,597,473</td>
<td>13,194,946</td>
<td>6,597,473</td>
</tr>
<tr>
<td>Permitting</td>
<td></td>
<td>1,102,166</td>
<td>2,204,332</td>
<td>1,102,166</td>
</tr>
<tr>
<td>Contingency</td>
<td></td>
<td>3,663,538</td>
<td>7,327,076</td>
<td>3,663,538</td>
</tr>
<tr>
<td>Total Installed</td>
<td></td>
<td>49,830,325</td>
<td>99,660,650</td>
<td>49,830,325</td>
</tr>
</tbody>
</table>

---

\textsuperscript{6} Cost estimated developed by TIAX under contract to Pacific Gas and Electric Company, 2009.
Ethanol

Under the BAU and LCFS compliance scenarios significant increases in ethanol consumption are anticipated. This is achieved through increasing the blend level in gasoline to 15% (in scenarios 2 and 3) and increased volumes of E85 consumption. The infrastructure costs can be divided into two main categories: ethanol production, handling and storage infrastructure and E85 blending, distribution and refueling infrastructure. Table 19 provides the total ethanol volumes for the BAU and compliance scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total Ethanol Consumed (million gal/yr)</th>
<th>Total Ethanol Consumed as E85</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>250</td>
<td>107</td>
</tr>
<tr>
<td>BAU – High Oil Prices</td>
<td>250</td>
<td>107</td>
</tr>
<tr>
<td>BAU – Low Oil Prices</td>
<td>249</td>
<td>107</td>
</tr>
<tr>
<td>Run 1 (Cellulosic with ILUC)</td>
<td>307</td>
<td>170</td>
</tr>
<tr>
<td>Run 1H (Cellulosic with ILUC, Out-of-State)</td>
<td>308</td>
<td>170</td>
</tr>
<tr>
<td>Run 2 (Mixed with ILUC)</td>
<td>403</td>
<td>198</td>
</tr>
<tr>
<td>Run 3 (Mixed no ILUC)</td>
<td>331</td>
<td>114</td>
</tr>
<tr>
<td>Run 3H (Mixed no ILUC, High Oil Prices)</td>
<td>332</td>
<td>115</td>
</tr>
<tr>
<td>Run 3L (Mixed no ILUC, Low Oil Prices)</td>
<td>329</td>
<td>113</td>
</tr>
<tr>
<td>Run 4 (EVs, cellulosic)</td>
<td>282</td>
<td>150</td>
</tr>
<tr>
<td>Scenario E: One Pool</td>
<td>302</td>
<td>167</td>
</tr>
</tbody>
</table>

Ethanol Production Facility Costs

The BAU and each gasoline pool scenario except Run 1H assume various volumes of in-state cellulosic ethanol production. The total cellulosic ethanol consumption was capped at the RFS2 high ethanol case proportional share volume. Table 20 provides the projected volumes of in-state cellulosic ethanol for each of these scenarios. Also shown is EPA’s estimate of average cellulosic production plant size in 2015 and corresponding plant installed cost. The number of in-state cellulosic ethanol plants is expected to range from 0 to 4, at a cost up to $880 million.

<table>
<thead>
<tr>
<th>Units</th>
<th>Existing In-State Capacity</th>
<th>New OR Production, 2022</th>
<th>Plant Size</th>
<th>New OR Plants by 2022</th>
<th>Capital Cost per Plant</th>
<th>Total Capital Cost by 2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MMGal/yr</td>
<td>MM Gal/yr</td>
<td>MMGal/yr</td>
<td></td>
<td>$MM</td>
<td>$MM</td>
</tr>
<tr>
<td>BAU</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>1H</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>One Pool</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Ethanol Transportation & Storage Costs
We assume here that no upgrades are needed at marine terminals to handle increased levels of sugarcane ethanol since these volumes are expected to enter through Seattle for U.S. compliance with RFS2. To transport the increased volumes of ethanol to the petroleum terminals (from rail, marine or production plants), new tanker trucks will be needed. Using the EPA RFS2 assumptions of 8000 gallon capacity and 6 trips per day per tanker truck, we estimate the numbers of new trucks needed by 2022 to transport increased volumes of ethanol to the petroleum terminals shown in Table 21.

| Table 21. Estimated Number of Tanker Trucks to Transport Ethanol to Petroleum Terminals |
|---------------------------------|---|---|---|---|---|---|
|                                  | Units  | Runs   |     |     |     | One |
|                                 |        | BAUb  | 1c  | 2   | 3d  | 4   |
| Ethanol Volumes, 2022           | MMgal/yr | 250  | 307 | 403 | 331 | 282 |
| Volume Increase from 2012       | MMgal/yr | 84   | 146 | 237 | 165 | 116 |
| Truck Capacitya                 | Gallons | 8,000 | 8,000 | 8,000 | 8,000 | 8,000 |
| Truck Trips per daya            |        | 6    | 6   | 6   | 6   | 6   |
| Total New Trucks by 2022        |        | 5    | 8   | 14  | 9   | 7   |
| Truck Price                     |        | $1000 | 180 | 180 | 180 | 180 |
| Total Cost of New Trucks        |        | $MM  | 0.90 | 1.44 | 2.52 | 1.62 |

- a. EPA RFS2 RIA Chapter 4.2
- b. BAU high and low oil same as BAU
- c. Scenario 1H out of state same as Scenario 1
- d. Scenario 3 high and low oil same as 3

To handle the increased volume of ethanol at the petroleum terminals, new storage tanks will need to be constructed (some petroleum tanks can be retrofit). Additional truck unloading, blending and ancillary equipment will also be needed. In the RFS2, EPA estimated these costs for the primary control case at 0.113 $/annual gallon of ethanol. This estimate includes a 15% working inventory and assumes that much of the storage capacity could be accommodated by tanks that had previously stored gasoline. Since ethanol has a lower energy density than gasoline, only 67% of the new ethanol storage capacity can be satisfied by modified existing gasoline storage tanks. The EPA value is utilized directly to estimate the petroleum terminal costs – results are shown in Table 22.

| Table 22. Petroleum Terminal Upgrade Costs, cumulative through 2023 |
|---------------------------------------------------------------|---|---|---|---|---|---|---|
|                                                              | Units  | BAU | 1, 1H | 2 | 3 | 3F | 3G | 4 | One Pool |
| Increased EtOH from 2012                                     | MMgal/yr | 84  | 146 | 237 | 165 | 166 | 163 | 116 | 137 |
| Terminal Upgrade Costsa                                      | $/gal/yr | 0.113 | 0.113 | 0.113 | 0.113 | 0.113 | 0.113 | 0.113 | 0.113 |
| Total Terminal Costs, 2022                                   | $Million | 9.5  | 16.5 | 26.9 | 18.7 | 18.8 | 18.5 | 13.1 | 15.5 |

- a. EPA RFS2 RIA Chapter 4.2
E85 Infrastructure
To handle increased E85 consumption, we consider costs associated with transporting E85 from terminals to fueling stations, and the fueling station costs. Modifications to refueling stations are considered here. In the RFS2 RIA, EPA assumes that 25% of gasoline refueling stations will have E85 dispensing equipment. Costs for adding E85 dispensing equipment varies greatly from $12,000 to $100,000. For this analysis it is assumed that installation of E85 dispensing equipment costs $75,000. Table 23 provides the estimated E85 dispensing costs for the BAU and all LCFS scenarios.

Table 23. Estimated E85 Refueling Infrastructure Costs, cumulative through 2023

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing Gasoline Stations</td>
<td>1061</td>
</tr>
<tr>
<td>Total Stations with E85 by 2022</td>
<td>265</td>
</tr>
<tr>
<td>Existing E85 Stations</td>
<td>MMGal/yr 4</td>
</tr>
<tr>
<td>New E85 Retrofits by 2022</td>
<td>% 261</td>
</tr>
<tr>
<td>Cost per Retrofit</td>
<td>$ 75,000</td>
</tr>
<tr>
<td>Total Cost by 2022</td>
<td>$Million 18.7</td>
</tr>
</tbody>
</table>

7 Conversation between Cory Ann Wind (OR DEQ) and Northwest Pump and Equipment
Biodiesel

A variety of assumptions have been made about the biodistillates used in the BAU and LCFS scenarios. Table 24 summarizes the projected volumes of biodistillates in 2022. As can be seen, in Runs 6, 7, 9 and the One Pool, the waste oil derived biodiesel consumption increases to 20 million gal/yr. It is assumed that the waste oil BD is all produced in Oregon, so a new biodiesel production plant is required for each of these scenarios. Run 7 and the One Pool Scenario have 8.4 million gal/yr of canola biodiesel above current Oregon production capacity. For these scenarios, it is assumed that the canola is grown in Oregon, but the biodiesel is produced out of state. This assumption is made because investment in such a small biodiesel production plant is unlikely. Finally, the BAU, 6, 9 and One Pool scenarios have in-state production of cellulosic diesel. For these scenarios, it is assumed that a new cellulosic diesel production plant is built in Oregon.

Table 24. Summary of Biodistillate Consumption in 2022, Million gal/yr.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>In-State Cellulosic</th>
<th>Out-of-State Cellulosic</th>
<th>In-State Canola</th>
<th>Out-of-State Canola</th>
<th>Camelina RD</th>
<th>Waste Oil BD</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>78.9</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>BAU, High Oil</td>
<td>79.0</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>BAU, Low Oil</td>
<td>78.7</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>6: Cellulosic with ILUC</td>
<td>96.2</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>20.0</td>
</tr>
<tr>
<td>6H: out-of-state cellulosic</td>
<td>0.0</td>
<td>96.2</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>20.0</td>
</tr>
<tr>
<td>7: Conventional w/ILUC</td>
<td>29.4</td>
<td>0.0</td>
<td>0.3</td>
<td>8.4</td>
<td>50.0</td>
<td>20.0</td>
</tr>
<tr>
<td>8: Conventional, no ILUC</td>
<td>0.0</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>8F: High Oil</td>
<td>0.0</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>8G: Low Oil</td>
<td>0.0</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>3.5</td>
</tr>
<tr>
<td>9: CNG &amp; Cellulosic</td>
<td>61.3</td>
<td>0.0</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
<td>20.0</td>
</tr>
<tr>
<td>One-Pool</td>
<td>34.7</td>
<td>0.0</td>
<td>0.3</td>
<td>8.4</td>
<td>50.0</td>
<td>20.0</td>
</tr>
</tbody>
</table>

1. Canola grown in Oregon, but BD produced out of state
2. Camelina grown outside of Oregon, RD produced outside of Oregon
3. Existing waste oil production capacity ~ 3.5 million gal/yr. All produced in Oregon.

It is assumed that a new plant to produce biodiesel from waste oil costs approximately $0.80 per annual gallon of capacity\(^8\). Therefore a 20 million gal/yr plant is estimated to cost ~ $16 million. Table 24 summarizes the scenarios that incur this cost.

Table 25. Scenarios Installing Waste Oil Biodiesel Production Capacity

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Waste Oil Biodiesel Plant Expenditure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run 6</td>
<td>$16 Million</td>
</tr>
<tr>
<td>Run 6h</td>
<td>$16 Million</td>
</tr>
<tr>
<td>Run 7</td>
<td>$16 Million</td>
</tr>
<tr>
<td>Run 9</td>
<td>$16 Million</td>
</tr>
<tr>
<td>Scenario E:</td>
<td></td>
</tr>
<tr>
<td>One Pool</td>
<td>$16 Million</td>
</tr>
</tbody>
</table>

\(^8\) Imperium Renewables plant in Washington State reported to cost $78 million for 100 million annual gallon capacity. Cnet.com, August 14, 2007.
New plants to produce cellulosic biodiesel will be needed for several of the scenarios. The capital costs for installing cellulosic biodiesel plant capacity are shown in Table 26. The plant size and capital cost are from EPA RFS2 RIA Chapter 4.1.

### Table 26. Estimated Cellulosic Diesel Production Plant Costs in Oregon by 2022

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>BAU</th>
<th>Run 6</th>
<th>Run 7</th>
<th>Run 9</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>In-State Cellulosic Production, 2022</td>
<td>MMGal/yr</td>
<td>79</td>
<td>96</td>
<td>29</td>
<td>61</td>
<td>35</td>
</tr>
<tr>
<td>Cellulosic BD Plant Capital Cost</td>
<td>$MM</td>
<td>346</td>
<td>346</td>
<td>346</td>
<td>346</td>
<td>346</td>
</tr>
<tr>
<td>Plant Size</td>
<td>MMGal/yr</td>
<td>33</td>
<td>33</td>
<td>33</td>
<td>33</td>
<td>33</td>
</tr>
<tr>
<td>Number of Plants in Oregon</td>
<td></td>
<td>2</td>
<td>3</td>
<td>1</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Installed Cost of Plants</td>
<td>$MM</td>
<td>692</td>
<td>1,038</td>
<td>346</td>
<td>692</td>
<td>346</td>
</tr>
</tbody>
</table>

Additional trucks are needed to transport biodistillate volumes from either the production plant or the rail terminal to the petroleum terminals. Table 27 provides the number of new trucks and associated cost needed by 2022 to transport BD from rail/plant to petroleum terminal using EPA’s assumptions from RFS2 RIA.

### Table 27. Estimated Cost of New Trucks to Transport BD to the Petroleum Terminals

<table>
<thead>
<tr>
<th></th>
<th>Run</th>
<th>Units</th>
<th>BAU</th>
<th>Run 6</th>
<th>Run 7</th>
<th>Run 8</th>
<th>Run 9</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase in BD Use by 2022</td>
<td>MMGal/yr</td>
<td>87</td>
<td>97</td>
<td>89</td>
<td>87</td>
<td>84</td>
<td>94</td>
<td></td>
</tr>
<tr>
<td>Truck Capacity</td>
<td>Gal</td>
<td>8,000</td>
<td>8,000</td>
<td>8,000</td>
<td>8,000</td>
<td>8,000</td>
<td>8,000</td>
<td></td>
</tr>
<tr>
<td>Truck Trips per Day</td>
<td></td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Number of New Trucks by 2022</td>
<td></td>
<td>5</td>
<td>6</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Cost per truck*</td>
<td>$1000</td>
<td>180</td>
<td>180</td>
<td>180</td>
<td>180</td>
<td>180</td>
<td>180</td>
<td></td>
</tr>
<tr>
<td>Total Cost of New Trucks by 2022</td>
<td>$Million</td>
<td>0.90</td>
<td>1.1</td>
<td>0.90</td>
<td>0.90</td>
<td>0.90</td>
<td>0.90</td>
<td></td>
</tr>
</tbody>
</table>

*EPA RFS2 RIA says 198,000 for heated trucks in colder climates, otherwise same as EtOH.

Upgrades at the petroleum terminals are needed to unload the tanker trucks, store the biodiesel and blend it into conventional diesel. The cost estimate for these upgrades is provided in Table 28, based on EPA’s RFS2 RIA Chapter 4.2.

### Table 28. Estimated Cost to Upgrade Petroleum Terminals to Unload, Store and Blend BD

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>Run</th>
<th>BAU</th>
<th>Run 6</th>
<th>Run 7</th>
<th>Run 8</th>
<th>Run 9</th>
<th>Scenario E: One Pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase in BD Use by 2022</td>
<td>MMGal/yr</td>
<td>87</td>
<td>97</td>
<td>89</td>
<td>87</td>
<td>84</td>
<td>94</td>
<td></td>
</tr>
<tr>
<td>Terminal Upgrade Cost</td>
<td>$/gal/yr</td>
<td>0.051</td>
<td>0.051</td>
<td>0.051</td>
<td>0.051</td>
<td>0.051</td>
<td>0.051</td>
<td></td>
</tr>
<tr>
<td>Cumulative Upgrade Cost by 2022</td>
<td>$Million</td>
<td>4.4</td>
<td>4.9</td>
<td>4.5</td>
<td>4.4</td>
<td>4.3</td>
<td>4.8</td>
<td></td>
</tr>
</tbody>
</table>
Biofuel Distribution to Refueling Stations

From the petroleum terminal, the biofuels are distributed to refueling stations. Table 29 summarizes the fuel volumes in 2012 and 2022 and provides the increase in fuel volumes delivered to refueling stations. The total number of distribution trucks required in 2022 is provided in Table 30.

Table 29. Increase in Fuel Volumes Delivered to Refueling Stations

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012 Volumes</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>1,528</td>
<td>1,483</td>
<td>1,527</td>
<td>1,527</td>
<td>1,525</td>
<td>1,526</td>
</tr>
<tr>
<td>E85</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Diesel</td>
<td>644</td>
<td>643</td>
<td>643</td>
<td>643</td>
<td>635</td>
<td>644</td>
</tr>
<tr>
<td>BD</td>
<td>19</td>
<td>19</td>
<td>19</td>
<td>19</td>
<td>19</td>
<td>19</td>
</tr>
<tr>
<td>Total</td>
<td>2,191</td>
<td>2,146</td>
<td>2,190</td>
<td>2,190</td>
<td>2,180</td>
<td>2,189</td>
</tr>
<tr>
<td>2022 Volumes</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>1,334</td>
<td>1,295</td>
<td>1,231</td>
<td>1,279</td>
<td>1,243</td>
<td>1,281</td>
</tr>
<tr>
<td>E85</td>
<td>126</td>
<td>200</td>
<td>233</td>
<td>134</td>
<td>176</td>
<td>197</td>
</tr>
<tr>
<td>Diesel</td>
<td>681</td>
<td>669</td>
<td>676</td>
<td>679</td>
<td>649</td>
<td>680</td>
</tr>
<tr>
<td>BD</td>
<td>106</td>
<td>116</td>
<td>108</td>
<td>106</td>
<td>103</td>
<td>113</td>
</tr>
<tr>
<td>Total</td>
<td>2,246</td>
<td>2,280</td>
<td>2,248</td>
<td>2,198</td>
<td>2,172</td>
<td>2,271</td>
</tr>
<tr>
<td>Total Increase</td>
<td>56</td>
<td>134</td>
<td>58</td>
<td>8</td>
<td>-8</td>
<td>82</td>
</tr>
</tbody>
</table>

Table 30. Number and Cost of Fuel Distribution Trucks

<table>
<thead>
<tr>
<th>Units</th>
<th>BAU</th>
<th>A &amp; H (1+6)</th>
<th>B (2+7)</th>
<th>C, F, G (3+8)</th>
<th>D (4+9)</th>
<th>E (One Pool)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume Increase from 2012</td>
<td>MMGal/yr</td>
<td>56</td>
<td>134</td>
<td>58</td>
<td>8</td>
<td>-8</td>
</tr>
<tr>
<td>Truck Capacity</td>
<td>gal</td>
<td>8000</td>
<td>8000</td>
<td>8000</td>
<td>8000</td>
<td>8000</td>
</tr>
<tr>
<td>Trips per day</td>
<td>trips/day</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>Trips per year</td>
<td>trips/year</td>
<td>2190</td>
<td>2190</td>
<td>2190</td>
<td>2190</td>
<td>2190</td>
</tr>
<tr>
<td>Number of trucks</td>
<td>3</td>
<td>8</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Cost per truck</td>
<td>$</td>
<td>180,000</td>
<td>180,000</td>
<td>180,000</td>
<td>180,000</td>
<td>180,000</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$Million</td>
<td>0.54</td>
<td>1.44</td>
<td>0.54</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>
**Compliance Scenario Descriptions**

- All Scenarios achieve a 10% reduction in carbon intensity by 2022.
- Where indirect land use change (ILUC) is included, the ILUC number is from California Air Resources Board’s low carbon fuel standard.

**Business-as-Usual**

- Assumes Oregon receives its proportional share of the federal Renewable Fuel Standard (RFS2) Primary Control Case biofuel volumes (cellulosic ethanol, cellulosic diesel, sugarcane ethanol, soybean ethanol, corn ethanol). Delayed use of cellulosic diesel until 2013.
- An E10 blendwall (a requirement to blend no more than 10% ethanol with gasoline) was assumed for the analysis period.
- E10 blendwall met in 2013, limiting gasoline from absorbing any additional ethanol required by RFS2. After this point E85 consumption begins to increase.
- Biodiesel blend level increases to ~13.5% by 2022 due to the federal RFS2.

**Gasoline Pool VISION Runs:**

In all cases, 26 million gallons per year of Northwest corn ethanol made from Midwest corn plus 1.75 million gallons per year of ethanol from waste berries.

**Scenarios**

**Scenario A – Cellulosic Biofuels with ILUC (Runs 1 + 6)**

Run 1 – Cellulosic Ethanol with ILUC (Produced In-State)

- In addition to Northwest corn ethanol and waste berry ethanol, compliance with standard achieved through use of in-state cellulosic ethanol.
- If more ethanol is needed to reach total RFS2 proportional share volumes, it comes from Midwest corn ethanol.

Run 6 – Cellulosic diesel with ILUC (Produced In-State)

- Compliance achieved through the use of new in-state cellulosic diesel and new waste oil biodiesel capacity

**Scenario B – Mixed Biofuels with ILUC (Runs 2 + 7)**

Run 2 – Mixed Ethanol with ILUC
In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of sugarcane ethanol, lower carbon intensity Midwest corn ethanol, and cellulosic ethanol.

So much ethanol was required here that the blend wall had to be increased to E12 (12% ethanol blended with gasoline) in 2017 and E15 (15% ethanol blended with gasoline) in 2020.

Run 7 – Conventional biodiesel with ILUC

Compliance achieved through:
- Moderate amounts of in-state cellulosic diesel production
- Out of state grown and produced camelina renewable diesel
- New In-state waste oil biodiesel capacity
- Existing in-state canola biodiesel
- New out-of-state canola biodiesel production from Oregon grown canola

Scenario C – Mixed Biofuels without ILUC (Runs 3 + 8)

Run 3 – Mixed Ethanol without ILUC

In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of sugarcane ethanol, lower carbon intensity Midwest corn ethanol, and cellulosic ethanol.

For comparison with Run 2 in Scenario B, we increased the blend wall to E12 in 2017 and E15 in 2020.

Run 8 – Conventional Biodiesel without ILUC

Compliance achieved through
- Existing canola biodiesel
- Existing waste oil biodiesel
- Midwest soybean biodiesel

Scenario D – Electricity, CNG and Cellulosic Biofuels with ILUC (Runs 4 + 9)

Run 4 – High Electric Vehicles with Cellulosic Ethanol with ILUC (Produced In-State)

In addition to Northwest corn ethanol and waste berry ethanol, compliance achieved through use of Electric Vehicles and Plug-In Hybrid Electric Vehicles plus in-state cellulosic ethanol.

Similar to Run 1 except more plug in vehicles are included, so less ethanol is required.

Run 9 – max CNG vehicles and cellulosic diesel with ILUC

Similar to 6, but more CNG vehicles are included so less biofuels are required.
Scenario E – One Pool

- Gasoline pool reductions achieved mainly through the use of in-state produced cellulosic ethanol (on top of existing Northwest corn ethanol and waste berry ethanol production).
- Plug-in vehicle populations double the BAU
- Diesel pool reductions achieved mainly through the use of in-state produced cellulosic diesel, new waste oil biodiesel capacity and imported camelina renewable diesel.
- Light-duty diesel populations increase, CNG populations increase

Scenario F – Mixed Biofuels without ILUC, high oil prices (Runs 3H+8H)

- Similar mix of fuels as Scenario C, but with higher oil prices (A new BAU was run as well)

Scenario G – Mixed Biofuels without ILUC, low oil prices (Runs 3L+8L)

- Similar mix of fuels as Scenario C, but with lower oil prices (A new BAU was run as well)

Scenario H – Cellulosic Biofuels with ILUC, Out-of-State (Runs 1H+6H)

Run 1H – Cellulosic Ethanol with ILUC (Produced Out-of-State)

- In addition to Northwest corn ethanol and waste berry ethanol, compliance with standard achieved through use of out-of-state cellulosic ethanol.
- If more ethanol is needed to reach total RFS2 proportional share volumes, it comes from Midwest corn.

Run 6H – Cellulosic biodiesel with ILUC (Produced Out-of-State)

- Compliance achieved through the use of out-of-state cellulosic diesel and new in-state waste oil biodiesel capacity, existing in-state canola biodiesel.
Memo

To: Cory-Ann Wind, Air Quality Planner, Oregon DEQ, (503) 229-5388, wind.cory@deq.state.or.us

From: Michael F. Lawrence, 301-961-8835, Lawrence@jfaucett.com

Date: December 11, 2012

Re: Other Macroeconomic Analyses of LCFS – Task 1 Report

Introduction

This report summarizes recent macroeconomic impact analyses focusing on scenarios involving the implementation of a low-carbon fuel standard. In these studies, the analyses sought, or are seeking, to estimate a) carbon reduction potential, b) fuel usage patterns, and c) economic impacts of a low-carbon fuel standard strategy. The studies covered were completed by the Center for Climate Strategies and the Governmental Studies faculty at Johns Hopkins University, Professor Adam Rose at the University of Southern California, the Washington State Department of Ecology, the California Air Resources Board, NESCAUM1, the California Climate Action Team, and Charles River Associates.

Most of these studies use econometric models, which are either custom-built programs or extensive spreadsheets that seek to quantify the economic impacts that result from certain expected changes to parts of the economy. Those changes may be driven by policy, as in the case of a low-carbon fuel standard, or by external market forces, as in the case of a rise in the market price of oil. The models are “econometric” in that they use statistical and mathematical methods to attempt to produce numeric measurements (usually in dollar amounts) of the impacts these changes would have.

Not all of these studies have similar scenarios, assumptions or methods to those utilized for the Oregon analysis. In addition, not all have been completed to the point where results have been published. The table below briefly summarizes the year of publication and the perceived similarity of each study to the work being completed for Oregon.

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1 NESCAUM stands for Northeast States for Coordinated Air Use Management.
<table>
<thead>
<tr>
<th>Study</th>
<th>Date of Publication</th>
<th>Similarity to Oregon Study and Usefulness for Comparison</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impacts of Comprehensive Climate and Energy Policy Options on the U.S. Economy</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Center for Climate Strategies and Johns Hopkins University</td>
<td>2010</td>
<td>Limited. Considers macro effects of biofuels only as part of a 23-policy bundle a) on a national scale and b) without detailed infrastructure assumptions</td>
</tr>
<tr>
<td>The Economic Impact of the Florida Energy and Climate Change Action Plan on the State’s Economy</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adam Rose and Dan Wei, University of Southern California</td>
<td>2008</td>
<td>Somewhat. A state-level study with macroeconomic analysis, finding $15 billion in direct savings from advanced biofuels savings. No macro analysis published for this strategy, however, beyond a projection of 11,000 net positive new jobs created from this strategy.</td>
</tr>
<tr>
<td>Washington State Low Carbon Fuel Standard Analysis</td>
<td>Expected 2010</td>
<td>Superior, but not yet complete. This study undertakes very similar methodologies and uses very similar sets of inputs and an equivalent LCFS scenario. Pathways and assumptions differ only slightly. Study not yet completed, however.</td>
</tr>
<tr>
<td>Northeast States Low Carbon Fuel Standard Analysis</td>
<td>Ongoing</td>
<td>Significant, but not yet complete. This study undertakes very similar methodologies and uses very similar sets of inputs. Pathways may differ; they have not yet been established. This study is in its beginning stages.</td>
</tr>
<tr>
<td>Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report</td>
<td></td>
<td></td>
</tr>
<tr>
<td>California Climate Action Team – Economics Subgroup</td>
<td>2006</td>
<td>Limited. As with Florida’s study, this study completes a macroeconomic analysis of a bundle of 40 climate strategies, but no individual results for major LCFS components. Also uses different methods and model types from Oregon’s approach.</td>
</tr>
<tr>
<td>Economic and Energy Impacts Resulting from a National Low-Carbon Fuel Standard</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Charles River Associates</td>
<td>2010</td>
<td>Very Limited. The study analyzes the impacts of a severe rationing regime imposed on gasoline and diesel, rather than the displacement of those fuels by lower-carbon-content alternatives. It specifically assumes that any new low-carbon fuel</td>
</tr>
</tbody>
</table>
capacity is impossible within the next 15 years, and thus models no such expansion. The likelihood of its other assumptions are open to question on political, technological and economic grounds.

| California Air Resources Board, Economic Impact Estimate of Low-Carbon Fuel Standard | 2009 | Somewhat. CARB’s analysis considered a similar LCFS standard and also considered several alternate pathways to achieving that standard over a 10-year period. However, their economic analysis was limited to direct microeconomic impacts, rather than a wider macroeconomic impact showing the effect on the economy as a whole. |
| National Low Carbon Fuel Standard Analysis University of California, Davis | Ongoing | Somewhat, but not yet complete. UC Davis researchers seek to complete a macroeconomic analysis of a national LCFS scenario. The scenario design is not yet complete and the analytical methods have not yet been publicly described. |

The ambition of this report is to provide a basis for the comparison of Oregon’s eventual results to those reported by other research and studies assessing the macroeconomic impacts attributable to the implementation of a low-carbon fuel standard. Given that purpose, a caveat regarding the research covered in this memo is appropriate at the outset. As the table above suggests, no existing completed study provides a valuable basis for direct comparison with the eventual results of the ongoing analysis currently underway in Oregon. The Washington LCFS macroeconomic analysis uses a very similar set of methods, assumptions and data, but that study has not yet been completed. The work by NESCAUM is also expected to use a similar methodology and a comparable set of economic models, but that study is also in its early phases. The national study by the Center for Climate Strategies includes macroeconomic analyses of certain biofuels and electric-vehicles strategies, but contains no analysis of an LCFS designed with any similarity to the standard contemplated by DEQ. It also fails to address related infrastructure spending in anything like the detail considered as part of Oregon’s analysis. Finally, the analysis by Charles River Associates, while purporting to address low-carbon fuel standards, is substantively an analysis of a severe federal petroleum-rationing scenario, and in fact specifically assumes no change from business as usual in the production, consumption or state of infrastructure regarding alternate fuels. It should be considered least germane of all to Oregon’s LCFS analysis.

For the purpose of providing current policy context, neither of the two versions of a federal climate-change bill proposed this year contained a low-carbon fuel standard requirement. Each addressed the carbon content of transportation fuels in a much more limited fashion. Waxman-Markey, the house bill and the bill generally
considered the more aggressive of the two, contained funding for smart-growth infrastructure spending, as well as higher fuel-efficiency standards and support for more plug-in hybrid-electric vehicle usage. It also contained funding for advanced biofuels. However, it did not contain a carbon-content standard for fuels. Kerry-Lieberman was also without an LCFS, and contained less specific support for biofuels than Waxman-Markey. However, both bills sought to expand natural-gas spending.\textsuperscript{23}

\textit{Center for Climate Strategies Studies}

The Center for Climate Strategies (CCS), in partnership with faculty at the University of Southern California, has completed multiple macroeconomic analyses of strategies that were close to low-carbon fuel standards. These analyses were done as part of larger studies of the impacts and efficacy of state-level climate action plans. These analyses were completed by CCS with consulting support. Professor Adam Rose and post-doctoral researcher Dan Wei at USC completed macroeconomic modeling work using the REMI-PI+ model in a consulting role to CCS. The president of CCS holds a post as a teaching fellow at Johns Hopkins University, which served as the publisher of CCS’s 2010 report, “Impacts of Comprehensive Climate and Energy Policy Options on the US Economy.”

1. Impacts of Comprehensive Climate and Energy Policy Options on the U.S. Economy
\textit{Center for Climate Strategies and Johns Hopkins University}

This study compiles and updates the findings of 16 comprehensive state climate action plans and extrapolates the results to the nation. This approach analyzed and extrapolated the environmental and economic impacts of 23 separate strategies (six in the transportation/land use sector). The study then takes those results and using a widely accepted econometric model projects the national impact of these policies on employment, incomes, gross domestic product (GDP) and consumer energy prices. Finally, using the bottom-up data developed by the states and aggregated here, the study models the national impact of major features of the Kerry-Lieberman (K-L) bill considered in Congress in 2009 and 2010.

No one of the six transportation-related strategies was identified as a LCFS strategy by name. Two strategies did address parts of an LCFS as assessed in other studies: a renewable-fuels (biofuels) strategy and an incentives and taxation strategy (“feebates”) to encourage shifting vehicle fleets to fuel-efficient and alternative-fuel vehicles.

\textsuperscript{2} Legislative Summary, Energy and Commerce Committee.
http://energycommerce.house.gov/Press_111/20090724/hr2454_housesummary.pdf
This study used the Regional Economic Models, Inc. (REMI) Policy Insight Plus (PI+) modeling software to be discussed below (REMI, 2009) to evaluate the macroeconomic impacts to the U.S. of implementing the 23 GHG mitigation super options across the states. The REMI model is the most widely used economic modeling software package in the U.S. and has been heavily peer reviewed. The model is used extensively to measure proposed legislative and other program and policy economic impacts across the private and public sectors by government agencies in nearly every state of the US.

The use of the REMI PI+ model involves the generation of a baseline forecast of the economy through 2020. Then simulations are run of the changes brought about through the implementation of the various GHG mitigation options. Again, this includes the direct effects in the sectors in which the options are implemented, and then the combination of multiplier (purely quantitative interactions) general equilibrium (price-quantity interactions) and macroeconomic (aggregate interactions) impacts. The differences between the baseline and the “counter-factual” simulation represent the total regional economic impacts of these policy options.

In order to perform macroeconomic impact analysis of climate action plans using REMI, information is needed on basic microeconomic considerations, such as the direct costs and direct savings of each GHG mitigation option, as well as on aspects that relate to macro linkages. The results reported in the state action plans include GHG reduction potentials, net cost/savings in Net Present Value (NPV), and cost-effectiveness (per ton cost/saving of GHG removed). The macro study needs more detailed and disaggregated information on both the costs and savings aspects. For example, program costs need to be disaggregated into capital cost, operation and maintenance (O&M) cost, and fuel cost; energy savings need to be specified in different types of energy and for specific economic sectors. In addition, all these data are needed for individual years in the study period (2010-2020).

This level of detailed information may not always be reported in the state action plans for each option. Therefore, it was necessary to obtain the calculation workbooks used to quantify the policy options, and to extract the data needed by the REMI analysis from the workbooks. Because of the time limitation of this study, the study focused its data collection for macroeconomic linkage variables on seven states (Colorado, Florida, Iowa, Michigan, North Carolina, Pennsylvania, and Washington) that were believed to be representative of national diversity, and used the weighted average costs and savings of each individual super option to get the scaled-up estimates at the national level.

Findings show potential national improvements from implementation of a top set of 23 major sector-based policies and measures drawn from state plans. If implemented U.S.-wide at all levels of government, the measures yield:

- 2.5 million net new jobs in 2020 and a $159.6 billion (in 2007$) expansion in GDP in 2020;
• Over $5 billion net direct economic savings in 2020, at an average net savings of $1.57 per ton of GHG emissions avoided or removed; and
• Consumer energy price reductions of 0.56% for gasoline and oil; 0.60% for fuel oil and coal; 2.01% for electricity; and 0.87% for natural gas by 2020.

Assuming full and appropriately scaled implementation of all 23 actions in all U.S. states, the resulting greenhouse gas (GHG) reductions would surpass national GHG targets proposed by President Obama and congressional legislation, and would reduce U.S. emissions to 27% below 1990 levels in 2020, equal to 4.46 billion metric tons of carbon dioxide equivalent (BMtCO2e). Estimates were developed for two additional scenarios – one envisioning the additional application of a cap-and-trade regime and the other envisioning a less broad adoption of the 23 policies in question.

2. The Economic Impact of the Florida Energy and Climate Change Action Plan on the State’s Economy

Adam Rose and Dan Wei, University of Southern California

This analysis analyzed the microeconomic and macroeconomic impacts of 28 climate change mitigation strategies selected by the Florida Action Team on Energy and Climate Change, which was itself appointed by the office of Governor Charlie Crist. Individual strategies were analyzed for greenhouse gas emissions reduction potential, as well as for microeconomic impacts such as direct costs and savings. The macroeconomic analysis assessed the strategies in concert. Analyses were conducted for the time period 2007 to 2025.

The macroeconomic analysis utilized the REMI model, customized to the state of Florida. The methodology involved running REMI analyses for each strategy individually. Once done, REMI was run modeling a scenario in which all strategies were applied simultaneously. As a result, any overlaps or synergies could be detected if the aggregate analysis produced numbers that differed from the sum of all the individual analyses. All quantified strategies in concert were estimated to produce a 0.66% increase in gross state product by the year 2025.

In the transportation sector, the most relevant greenhouse gas mitigation strategy is one focused on developing and expanding low-GHG fuels. The individual microeconomic analysis found this strategy to be a possible money-saver, representing a possible savings of approximately $15 billion (in 2000 dollars) statewide by the year 2025. This represents a net savings of $142 per metric ton of GHG emissions avoided over the same time period. From the macroeconomic analysis, the low-GHG fuels strategy was projected to produce a positive impact in gross state product of nearly a billion dollars by 2025, and nearly four billion dollars over the period of analysis. The model also projected that this strategy would produce over 11,000 jobs per year above the baseline by the year 2025.
The results from the application of a renewable-fuels standard in Florida were also positive – the 20% renewable electricity supply by 2020 was projected to produce 4.5 billion dollars in additional gross state product by 2025, and over 16 billion dollars over the period of analysis.

**Similar Reports**

Similar reports were completed by the same authors for the states of Michigan, Pennsylvania and Wisconsin. As was the case in the Florida report, the authors (Rose and Wei, sometimes with co-authors) took estimates produced from stakeholder-based processes run by the Center for Climate strategies. Those microeconomic outputs from analyses of individual strategies were converted to inputs for REMI models, and aggregate macroeconomic impacts were estimated using the REMI tool.

Despite this similarity of process, the reports produced different estimates of economic impacts from different strategies. This is due to several factors:

1. Different states’ stakeholder processes established different strategies regarding low-carbon fuels or biofuels; some set targets while others proposed incentives.
2. Periods of analysis differed in terms of duration, start date and end date.
3. Different analyses established different assumptions about fuel prices, economic activity, transportation behaviors and other important factors.

In Michigan, their analysis found that a strategy encouraging low-carbon fuels would create direct costs of about $820 million statewide, working out to about $16 per ton of emissions avoided. No single-policy macroeconomic impact was completed. In Pennsylvania and in Wisconsin, no relevant strategy was analyzed.

**3. Washington State Low Carbon Fuel Standard Analysis**

*Washington State Department of Environmental Quality*

Washington’s Department of Ecology recently commissioned a study measuring the economic impacts of a low-carbon fuel standard applied statewide.

The methodology utilized in Washington is substantially the same as will be utilized in Oregon. Washington identified six distinct scenarios, each envisioning a combination of a heavy-duty biofuels pathway and a light-duty biofuels pathway. The initial step involved developing a version of Argonne National Labs’ Vision model for the state of Washington. Using this tool, TIAX LLC consultants developed an array of estimates from each of the six scenarios. These estimates included resulting fuel volumes of all fuels, energy usage, direct expenditures on
vehicles and fuels, and full fuel-cycle greenhouse gas emissions impacts. Jack Faucett Associates then developed inputs to macroeconomic models from those Vision analyses, as well as inputs for the costs related to the production, transportation, storage and fueling infrastructure needed for a changed transportation fuel mix. Finally, the Washington State, Office of Financial Management (OFM) is utilizing the REMI PI+ macroeconomic analysis model to develop a full range of macroeconomic impacts from each scenario.

Six low-carbon fuel standard scenarios were analyzed, representing six different approaches to achieving the target goal by the year 2023. They were as follows:

2. Scenario B: Expansion of cellulosic ethanol and biodiesel supply, but from out-of-state feedstocks.
3. Scenario C: Expansion of ethanol and biodiesel from a blend of feedstocks (not all cellulosic). This approach involved incentivizing E85 vehicles in the light-duty fleet and expanding canola biodiesel production from in-state feedstocks.
4. Scenario D: Expansion of electric vehicle use and cellulosic ethanol from in-state feedstocks, as well as expanding canola biodiesel production from in-state feedstocks.
5. Scenario E: Expansion of electric vehicle use and cellulosic ethanol from out-of-state feedstocks, as well as expanding canola biodiesel production from in-state feedstocks.
6. Scenario F: A one-pool approach to a single overall target for light-duty and heavy-duty fuels. This involved maximizing in-state canola biodiesel production, consuming twice the targeted goal for ethanol set in the RFS2 standard passed as part of the EISA 2007 legislation, and applying sugarcane and corn ethanol as needed to reach the 10% reduction target.

The graphic below seeks to summarize the components of Washington’s six pathway scenarios for easy comparison:

<table>
<thead>
<tr>
<th>Source of New Biofuels – In State or Out?</th>
<th>Type of New Biofuels</th>
<th>Any Electric or Plug-in Hybrid Strategy?</th>
<th>Any Alternate Low-Carbon Fuels?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario A</td>
<td>In-State</td>
<td>All Cellulosic</td>
<td>None</td>
</tr>
<tr>
<td>Scenario B</td>
<td>Out-of-State</td>
<td>All Cellulosic</td>
<td>None</td>
</tr>
<tr>
<td>Scenario C</td>
<td>Some of Each</td>
<td>Part Cellulosic</td>
<td>None</td>
</tr>
<tr>
<td>Scenario D</td>
<td>In-State</td>
<td>Part Cellulosic</td>
<td>EV/PHEV Infrastructure and tax credit</td>
</tr>
<tr>
<td>Scenario E</td>
<td>Out-of-State</td>
<td>Part Cellulosic</td>
<td>EV/PHEV Infrastructure and</td>
</tr>
</tbody>
</table>

Summary of Washington LCFS Scenarios
The Washington state analysis is still ongoing, so results have not yet been finalized or reported.

4. NESCAUM Low-Carbon Fuel Standard Macroeconomic Analysis (ongoing)

NESCAUM (Northeast States for Coordinated Air Use Management) is in the process of completing a macroeconomic analysis for its region. Its methodology is almost exactly that being used in Washington, and contemplated in Oregon. They are beginning with emissions factor development specific to the region using the GREET model. Those emissions factors are then applied to a customized VISION model built to represent the region. Fuel, vehicle, energy and direct-cost outputs are developed through analyses in Vision. Those outputs are then converted to inputs suitable for REMI analysis, and REMI analysis will be completed as the final step.

5. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report

California Climate Action Team – Economics Subgroup

This report is included for completeness, but is less germane in that it does not develop a macroeconomic impact for a low-carbon fuel standard. Instead, it estimates macroeconomic impacts for a combined bundle of forty strategies proposed to California’s Climate Action Team. The forty strategies ranged across sectors and were not limited to the transportation sector, but did include higher biodiesel and ethanol blend requirements.

The strategies were not assessed for macroeconomic impacts on an individual basis. The bundle of strategies was assessed as a whole. The process involved the use of two distinct macroeconomic models, the Environmental Dynamic Revenue Analysis Model (E-DRAM) from CARB and the Berkeley Energy and Resources model (BEAR), provided by UC Berkeley. Both are Computable General Equilibrium models. Each model was run independently, and the results were compared. The E-DRAM model showed slight improvements over baseline projections for gross state output, personal income and employment (less than 1% for all three indicators), and the BEAR model showed very slight reductions in gross state output and personal income (-0.1 and -0.6% respectively), but slightly positive changes in employment (0.2%).
6. Economic and Energy Impacts Resulting from a National Low-Carbon Fuel Standard

Charles River Associates

This study was completed in June 2010, and considered a scenario in which the United States would adopt a low-carbon fuel standard akin to California’s over the period 2015 to 2025.

California’s low-carbon fuel standard mandates a gradual reduction in the carbon intensity of gasoline and diesel (and any substitutes for gas and diesel) over a 10-year period from 2011 to 2020. Fuels must be 0.5% less carbon-intense in 2011 than they are in 2010, and progressively less carbon intense until they achieve a 10% reduction from 2010 measurements in the year 2020.

This report uses as its scenario the same 10-year gradual reduction in carbon intensity of transportation fuels, with three important differences:

1. The period of analysis is 2015 to 2025, rather than 2010 to 2020
2. The low-carbon requirement appears to be applied to all transportation fuels, rather than just gasoline and diesel
3. The scenario is nation-wide, rather than simply applied to California.

The import of these differences is primarily that the supply of alternative fuels becomes an issue. While a single state (even a large state) consumes only a few percent of the national demand for transportation fuels, and can source feedstocks for alternative fuels from around the country, a nation-wide low-carbon mandate faces the prospect of an insufficient supply of alternate fuels to achieve the carbon-intensity reduction required.

The report takes as a given that the US does not, and will not, have sufficient biofuels to add to the fuel supply in order to reach 10% reductions in fuel carbon-intensity by 2025. They also assume that the 15-year horizon is too short for any new fuel infrastructure to be constructed, or for any new technologies to be made operational. The authors assume that the federal government, in order to meet the standard despite this shortfall, will simply ration gasoline and diesel in order to achieve the necessary mix of fuels.

The authors assume this rationing will drive significant gas price rises – 30 to 80% within 5 years and 90 to 170% by 2025. Because gas is rationed, light and heavy duty VMT, including freight movement, is also assumed to be constrained, by between 9 and 14% below the baseline. Overall macroeconomic impacts are predicted to be dire: GDP would fall by 2 to 3%, employment would fall by between 2.3 and 4.5 million jobs.
The methodology of CRA’s economic analysis is not laid out in great detail. They utilize a pair of proprietary modeling and analysis tools, a Multi-Region National model and a National Electricity and Environment Model (referred to as MRN-NEEM when used in concert). Baseline energy-use and fuel price assumptions are taken from the Energy Information Administration.

The assumptions underlying this analysis merit some question. The assumption that the federal government would impose restrictive measures to comply with an LCFS mandate is at variance with recent real-world experience. The federal government already has a policy similar to a national LCFS in the form of the renewable-fuels mandate (RFS2) included as part of the EISA legislation in 2007. Like an LCFS, RFS2 sets an aggressive target: it requires that progressively more biofuels be mixed with standard fuels, reaching 36 billion gallons by 2022. Also like an LCFS, this target is considered to be unattainable. The Department of Energy’s EIA fuel-use projections currently expect the US fuel supply will achieve only about half the RFS2 standard. Despite this mandate and the perceived shortfall in supply, no federal action as of now has occurred that would force compliance with RFS2. It is unlikely that an LCFS would receive different treatment, let alone so extreme a treatment as restraints on the supply of conventional fuels.

In addition, biodiesel and ethanol are primarily consumed as components of gasoline blends, rather than as substitutes for gasoline. Because those blends are capped at low fixed ratios, restraining gasoline and diesel consumption would restrain biofuels consumption as well, and would be a self-defeating approach to achieving a low-carbon fuel standard.

The assumption that no new infrastructure or technology progress could be made within 15 years is also open to question. In the analysis of economic impacts from a LCFS in Washington State, this team found that advanced ethanol refining facilities require only a two-year period for construction (though site selection and permitting could add more years to the timeframe). Pipeline construction, even if delayed by debates over site selection and rights of way, requires less than 15 years for completion.

While the assumptions behind the results of this analysis are debatable, the same often holds true for other reports. Just as this report assumes no possibility of new infrastructure or technologies between now and 2025, other reports often assume that new fuels or vehicle technologies will be freely available, and that costs will be low. The assumptions underlying each analysis often define the character of the results projected.

   http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf
As part of the proposal for a low-carbon fuel standard for the state of California, the state’s Air Resources Board estimated the economic impacts associated with the implementation of such a standard. The LCFS in California seeks to achieve a 10% reduction in the carbon intensity of fuels consumed by the transportation sector over a ten-year period, much like the LCFS under review in both Washington and Oregon.

As with Washington and Oregon, this analysis considered several pathways through which the state could achieve the LCFS target. They involved different levels of reliance on different alternatives to gasoline and diesel. The table below summarizes the pathways:

<table>
<thead>
<tr>
<th>Source of New Biofuels – In State or Out?</th>
<th>Type of New Biofuels</th>
<th>Any Electric or Plug-in Hybrid Strategy?</th>
<th>Any Alternate Low-Carbon Fuels?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline Scenario 1</td>
<td>NotStated</td>
<td>Corn Ethanol Gradually Replaced by Cellulosic</td>
<td></td>
</tr>
<tr>
<td>Gasoline Scenario 2</td>
<td>NotStated</td>
<td>Corn Ethanol Quickly Replaced by Cellulosic</td>
<td></td>
</tr>
<tr>
<td>Gasoline Scenario 3</td>
<td>NotStated</td>
<td>Corn Ethanol Quickly Replaced by Cellulosic</td>
<td>PHEVs, BEVs, FCVs at 2X business as usual; displaces some ethanol</td>
</tr>
<tr>
<td>Gasoline Scenario 4</td>
<td>NotStated</td>
<td>Corn Ethanol Quickly Replaced by Cellulosic</td>
<td>PHEVs, BEVs, FCVs at 4X business as usual; displaces much ethanol</td>
</tr>
<tr>
<td>Diesel Scenario 1</td>
<td>NotStated</td>
<td>Conventional Biodiesel</td>
<td></td>
</tr>
<tr>
<td>Diesel Scenario 2</td>
<td>NotStated</td>
<td>Conventional and Advanced Biodiesel</td>
<td>Increased Compressed Natural Gas</td>
</tr>
<tr>
<td>Diesel Scenario 3</td>
<td>NotStated</td>
<td>Conventional and Advanced Biodiesel</td>
<td>PHEV vehicles to displace diesel</td>
</tr>
</tbody>
</table>

The CARB assessment found that an LCFS would produce a net savings in total fuel expenditure of $11 billion over the duration of the 10-year period. The analysis found this to be equivalent to less than $0.08 per gallon of fuel consumed, or below three percent of the current fuel cost. State and local sales tax revenues were expected to fall as a result. By 2020, those revenues are projected to fall between...
$78 million and $421 million below the business-as-usual scenario. Projections for job impacts are neutral to slightly positive.

In this analysis, CARB made an important assumption, deciding that much of the infrastructure needed for a rapid growth in low-carbon fuels could be expected to be built up as part of the federal biofuels mandate known as RFS2. As a result, they assumed no expenses for infrastructure for ethanol (a major component of the LCFS) in their economic analysis.

The CARB staff did not utilize any macroeconomic model as part of this analysis. They instead created a fairly detailed estimate of direct fuel costs and savings, as well as direct compliance costs (in the form of capital costs for new infrastructure). The wider impacts to various sectors of the economy were not estimated. As a result, this analysis should be considered a microeconomic analysis. The analysis also did not consider all alternate pathways in full detail, and did not produce different impacts from different investments in advanced vehicles or advanced fuels.

**McKinsey and Company Low-Carbon Economic Analysis Tool**

McKinsey and Company have developed their own proprietary analytical approach to macroeconomic scenario analysis, consisting of five distinct proprietary data sets and analytical tools. The overall result, however, is a distinct set of inputs to apply to the REMI model. REMI is then utilized to produce macroeconomic impact estimates. McKinsey’s fills the same role as the first phase of the process used for both Oregon and Washington, in which extensive work is done to develop customized projections of the microeconomic impacts of various low-carbon fuel pathways. As is done with the results of McKinsey’s proprietary approach, those projections are then expressed as inputs to the REMI model, which estimates larger macroeconomic impacts. McKinsey has not made its methodology public, and as such their approach is unavailable for a more detailed analysis.

**University of California, Davis: National Low Carbon Fuel Standard Analysis**

**Lead Researchers:** Daniel Sperling, Professor (ITS - Davis), Sonia Yeh, Research scientist (ITS - Davis), James Rhodes, Researcher (UC San Diego)

This project is a collaborative effort between several academic institutions and national research organizations to assess a national LCFS. We have requested additional information on the macroeconomic analysis planned and status from the study team. The study web site describes the project as follows.

This study has two objectives: 1) design an effective and implementable national LCFS; and 2) compare an LCFS with other policy instruments that have the potential to significantly reduce transportation GHG emissions from fuel use.
The study will propose a design of a robust national LCFS policy that balances environmental, political, and economic goals and is readily implementable and enforceable (in terms of data availability, simplicity, etc). The study will consider regional differences in resource availability, compliance costs, economic opportunities and policy impacts, and the sustainability safeguards needed to ensure an effective environmental performance of fuel policies. We will recommend a design of policy instruments for implementing a national LCFS based on the lessons learned from our study. We will examine the potential for innovation of low carbon fuels that will be encouraged by an LCFS policy and in particular the type of feedstocks and technologies that will be used and their implications for regional land use, infrastructure needs, food and fuel prices, and other environmental impacts in the U.S.

This project is ongoing and some of the research is evolving and may change before the final reports are prepared. At the present time, it does not appear that a separate macro-economic analysis will be conducted within this study.4

Resources


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4 See the department website dedicated to this analysis at [http://steps.ucdavis.edu/research/Thread_6/lcfs/national-lcfs](http://steps.ucdavis.edu/research/Thread_6/lcfs/national-lcfs) for further information.
Appendix F: Compliance Scenario Documentation

Oregon Low Carbon Fuel Standards Report
Agenda

1. Analysis Overview & VISION Model Prep
2. Business-As-Usual Assumptions & Results
3. Gasoline Pool VISION Results
4. Diesel Pool VISION Results
5. One-Pool VISION Results

Appendix
Agenda

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5. One-Pool VISION Results
Appendix
Objective: Estimate LCFS Impact on State Economy

Approach: Evaluate a Range of Possible Compliance Scenarios and compare them to BAU

**TIAx Tasks**
- Define Business As Usual (BAU)
- Define Compliance Scenarios
- Run VISION Model

**Define Alternative Fuel Infrastructure Costs**

**Create REMI Inputs**

**Run REMI Model**

**JFA Tasks**

Economic Impact of Scenarios relative to BAU
VISION Model Inputs and Outputs

- Consumer fuel and vehicle expenditures used directly in Economic Modeling
- Vehicle populations and alternative fuel volumes used to estimate infrastructure costs used in Economic Modeling

Historic and Future
- Total new vehicle sales each year
- Share of new vehicle sales by class, fuel/technology type
- Vehicle miles by class, model year
- Vehicle fuel economy by class, fuel/tech type and model year
- Carbon intensity for each fuel consumed
- Fuel prices
- Vehicle prices

Projection of:
- Vehicle population by class, fuel/tech type, model year
- Annual vehicle fuel consumption by type/vehicle class
- Average carbon intensity
- Consumer fuel expenditures
- Consumer vehicle expenditures
Scale VISION (U.S.) Vehicle Populations to Oregon

• VISION uses annual vehicle sales to estimate populations, and vehicle expenditures

• Vehicle Categories in VISION
  – Class: Light-duty auto (LDA), Light-duty truck (LDT), Medium-duty vehicle (MDV) (class 3-6), Heavy-duty vehicle (HDV) (class 7-8)
  – Fuel/Technology type: Flex-fuel vehicle (FFV), Hybrid-electric vehicle (HEV), Plug-in hybrid electric vehicle (PHEV), Electric vehicle (EV), CNG, diesel, gasoline

• Legacy Fleet: OR DOT database classifies vehicles as light duty or truck
  – Light Duty
    - Not all records indicate LDA vs LDT
    - Using WA split for LDA/LDT
    - Fuel types are specified
  – Medium Duty
    - DOT “Truck” and pass vehicles > 10,000 GVW
    - Deleted farming vehicles
    - Deleted heavy fixed construction
  – Heavy Duty Vehicles from Motor Vehicle Carrier Division
    - Oregon registered vehicles
    - Pass-Through vehicles not included
Scale VISION (U.S.) Vehicle Populations to Oregon

• Future Annual Vehicle Sales (2010+)
  – Use Energy Information Administration’s Annual Energy Outlook (AEO) U.S. vehicle sales projections
  – Scale with 10 yr avg ratio of Oregon new car sales to U.S. new car sales

<table>
<thead>
<tr>
<th>Vehicle Class</th>
<th>Oregon Share of U.S. Sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light Duty Auto</td>
<td>0.93%</td>
</tr>
<tr>
<td>Light Duty Truck</td>
<td>1.03%</td>
</tr>
<tr>
<td>Medium Duty Truck</td>
<td>1.6%</td>
</tr>
<tr>
<td>Heavy Duty Truck</td>
<td>0.84%</td>
</tr>
</tbody>
</table>
Adjusted Light Duty Plug-in Vehicle Sales

- Oregon HEV market share is 2X National sales rate
- Assume PHEV/EV sales are 2X National sales rate
- Add 1000 EVs in 2010 due to Oregon participation in The EV Project¹
- Increased Ratio of EV:PHEV² from 1:99 to 1:6 till 2017, from 2018+ adjusted EV sales to meet Zero-Emission Vehicle (ZEV) requirements, balance PHEVs

### 2022 Forecast

<table>
<thead>
<tr>
<th></th>
<th>Light Duty Auto</th>
<th>Light Duty Truck</th>
<th>Total Light Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHEV Market Share</td>
<td>1.83%</td>
<td>0.50%</td>
<td>1.27%</td>
</tr>
<tr>
<td>PHEV Population</td>
<td>17,580</td>
<td>4,348</td>
<td>21,927</td>
</tr>
<tr>
<td>EV Market Share</td>
<td>2.35%</td>
<td>0.65%</td>
<td>1.64%</td>
</tr>
<tr>
<td>EV Population</td>
<td>16,919</td>
<td>2,565</td>
<td>19,484</td>
</tr>
<tr>
<td>Total LDV Population</td>
<td>1,399,968</td>
<td>1,259,549</td>
<td>2,659,417</td>
</tr>
<tr>
<td>PHEV Fleet Share</td>
<td>1.3%</td>
<td>0.3%</td>
<td>0.8%</td>
</tr>
<tr>
<td>EV Fleet Share</td>
<td>1.2%</td>
<td>0.2%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>

¹. The EV Project is an ARRA project in which 4700 Nissan Leafs will be sold with free home chargers in five U.S. cities including Portland, Eugene, Salem, Corvalis.
². Based on Analyst estimates ranging from 1:9 and 1:1 (provided by WA Dept of Ecology)
Added Medium and Heavy Duty CNG Vehicles

- VISION does not include medium and heavy duty CNG vehicles
- Using AEO2009 market share values for medium & heavy duty CNG vehicles

<table>
<thead>
<tr>
<th></th>
<th>Light Duty</th>
<th>Medium Duty</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022 Market Share</td>
<td>0.06%</td>
<td>6.1%</td>
<td>1.9%</td>
</tr>
<tr>
<td>2022 Population</td>
<td>1,320</td>
<td>2,091</td>
<td>955</td>
</tr>
</tbody>
</table>
Light Duty Vehicles

- **EV**
- **CNG**
- **Diesel HEV**
- **Gasoline PHEV**
- **Diesel**
- **E85 FFV**
- **Gasoline HEV**
- **Gasoline**

### 2022 Populations

<table>
<thead>
<tr>
<th></th>
<th>LDA</th>
<th>LDT</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>962,209</td>
<td>817,338</td>
<td>1,779,547</td>
</tr>
<tr>
<td>Diesel</td>
<td>45,053</td>
<td>80,300</td>
<td>125,353</td>
</tr>
<tr>
<td>EtOH FFV</td>
<td>120,734</td>
<td>246,694</td>
<td>367,428</td>
</tr>
<tr>
<td>Gasoline HEV</td>
<td>235,297</td>
<td>107,475</td>
<td>342,772</td>
</tr>
<tr>
<td>Diesel HEV</td>
<td>1,483</td>
<td>204</td>
<td>1,687</td>
</tr>
<tr>
<td>Gasoline PHEV</td>
<td>17,580</td>
<td>4,348</td>
<td>21,927</td>
</tr>
<tr>
<td>Battery EV</td>
<td>16,919</td>
<td>2,565</td>
<td>19,484</td>
</tr>
<tr>
<td>CNG</td>
<td>693</td>
<td>626</td>
<td>1,319</td>
</tr>
<tr>
<td>Total</td>
<td>1,399,968</td>
<td>1,259,549</td>
<td>2,659,517</td>
</tr>
</tbody>
</table>

**Graph:***
- **Population (thousands)**
- **Legend:**
  - EV
  - CNG
  - Diesel HEV
  - Gasoline PHEV
  - Diesel
  - E85 FFV
  - Gasoline HEV
  - Gasoline
Medium & Heavy Duty Vehicles

- These are vehicles registered in Oregon – does not include pass through
- Does not include Diesel hybrid electric vehicles– very small, negligible impact on fuel consumption, no impact on carbon intensity
- Does not include LNG – very small and similar carbon intensity to CNG
Verify VISION VMT and Fuel Consumption Results

• Once vehicle populations are defined, VISION calculates
  – Vehicle Miles Traveled (VMT)
    - For each vehicle class and fuel type
    - Use VISION default VMT values – function of model year and vehicle class
  – Fuel consumption
    - For each vehicle class and fuel type
    - Function of population, VMT and fuel economy

• Calibrate Model
  – Compare VISION VMT to Oregon historic VMT
  – Compare VISION predicted fuel consumption to historic fuel consumption

• For Light Duty vehicles, predicted VMT is too low
  – Increased VMT by a factor of 1.23
  – Resulting gasoline consumption for 2006-2008 within 5% of actual

• Medium Duty vehicles – no adjustment necessary

• Heavy Duty – adjusted to account for fuel consumed by “pass-through”
Verify VISION VMT and Fuel Consumption Results

• Adjusted light duty VISION VMT by factor of 1.23
• Predicted gasoline consumption now ~ matches historic actual
Verify VISION VMT and Fuel Consumption Results

- Did not adjust Medium duty VMT
- Medium duty VMT affects both gasoline and diesel consumption predictions
Verify VISION VMT and Fuel Consumption Results

- Adjust HD VMT to account for “Pass-Through” trucks
- VISION predicted diesel consumption ~ historic actual
Agenda

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Appendix
### BAU Assumptions & Results

#### Baseline Carbon Intensity Values (WITH Indirect Land Use Change (ILUC))

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>Baseline Year (2010)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gasoline Baseline Carbon Intensity</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Blendstock Carbon Intensity</td>
<td>g CO2e/MJ</td>
<td>92.34</td>
</tr>
<tr>
<td>Neat Ethanol Carbon Intensity¹</td>
<td>gCO2e/MJ</td>
<td>92.80</td>
</tr>
<tr>
<td>Ethanol Blend Level²</td>
<td>% vol</td>
<td>10%</td>
</tr>
<tr>
<td>Neat Ethanol Blend Level</td>
<td>% energy</td>
<td>6.7%</td>
</tr>
<tr>
<td>Gasoline Baseline Carbon Intensity</td>
<td>gCO2e/MJ</td>
<td><strong>92.4</strong></td>
</tr>
<tr>
<td><strong>2022 Target</strong></td>
<td>gCO2e/MJ</td>
<td><strong>83.1</strong></td>
</tr>
<tr>
<td><strong>Diesel Baseline Carbon Intensity</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ULSD Carbon Intensity</td>
<td>gCO2e/MJ</td>
<td>91.53</td>
</tr>
<tr>
<td>Biodiesel Carbon Intensity³</td>
<td>gCO2e/MJ</td>
<td>63.66</td>
</tr>
<tr>
<td>BD Blend Level</td>
<td>% energy</td>
<td>2.1%</td>
</tr>
<tr>
<td>Diesel Baseline Carbon Intensity</td>
<td>gCO2e/MJ</td>
<td><strong>90.9</strong></td>
</tr>
<tr>
<td><strong>2022 Target</strong></td>
<td>gCO2e/MJ</td>
<td><strong>81.9</strong></td>
</tr>
</tbody>
</table>

1. Assumes 26 Mgal/yr Boardman corn ethanol, 0.37 Mgal/yr waste berry ethanol, balance MW corn ethanol
2. Denatured ethanol - assumed to be 2% by vol gasoline blendstock
3. Assumes 10 Mgal/yr MW soybean BD, 3.5 Mgal/yr waste oil BD, and 0.3 Mgal/yr canola BD

- Corn ethanol assumes CARB ILUC value -- 30 g/MJ ILUC
- Soybean biodiesel assumes CARB ILUC value – 62 g/MJ
### Baseline Carbon Intensity Values (WITHOUT ILUC)

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>Baseline Year (2010)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gasoline Baseline Carbon Intensity</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Blendstock Carbon Intensity</td>
<td>$g \text{CO}_2\text{e}/\text{MJ}$</td>
<td>92.34</td>
</tr>
<tr>
<td>Neat Ethanol Carbon Intensity¹</td>
<td>$g\text{CO}_2\text{e}/\text{MJ}$</td>
<td>62.90</td>
</tr>
<tr>
<td>Ethanol Blend Level²</td>
<td>% vol</td>
<td>10%</td>
</tr>
<tr>
<td>Neat Ethanol Blend Level</td>
<td>% energy</td>
<td>6.7%</td>
</tr>
<tr>
<td>Gasoline Baseline Carbon Intensity</td>
<td>$g\text{CO}_2\text{e}/\text{MJ}$</td>
<td>90.38</td>
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<tr>
<td>2022 Target</td>
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<tr>
<td><strong>Diesel Baseline Carbon Intensity</strong></td>
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<td></td>
</tr>
<tr>
<td>ULSD Carbon Intensity</td>
<td>$g\text{CO}_2\text{e}/\text{MJ}$</td>
<td>91.53</td>
</tr>
<tr>
<td>Biodiesel Carbon Intensity³</td>
<td>$g\text{CO}_2\text{e}/\text{MJ}$</td>
<td>18.55</td>
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<tr>
<td>BD Blend Level</td>
<td>% energy</td>
<td>2.1%</td>
</tr>
<tr>
<td>Diesel Baseline Carbon Intensity</td>
<td>$g\text{CO}_2\text{e}/\text{MJ}$</td>
<td>90.00</td>
</tr>
<tr>
<td>2022 Target</td>
<td></td>
<td>81.00</td>
</tr>
</tbody>
</table>

1. Assumes 26 Mgal/yr Boardman corn ethanol, 0.37 Mgal/yr waste berry ethanol, balance MW corn ethanol
2. Denatured ethanol - assumed to be 2% by vol gasoline blendstock
3. Assumes 10 Mgal/yr MW soybean BD, 3.5 Mgal/yr waste oil BD, and 0.3 Mgal/yr canola BD

- Corn ethanol value has NO ILUC component
- Soybean biodiesel has NO ILUC component
RFS2 Biofuels: Oregon’s Proportionate Share

- Proportionate share of EPA Renewable Fuel Standard (RFS2) Primary Control Case
- Scaled with ratio of projected OR gasoline and diesel consumption relative to projected U.S. consumption

<table>
<thead>
<tr>
<th>Oregon Proportionate Share of RFS2 Volumes</th>
<th>% GHG Reduction</th>
<th>Million Gallons/yr (2022)</th>
<th>Minimum Volume Requirement</th>
<th>EPA Analysis Primary Control Case</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Ethanol Equivalent</td>
<td>Actual Volumes</td>
<td>Ethanol Equivalent</td>
</tr>
<tr>
<td>Total Renewable Fuel</td>
<td></td>
<td>425</td>
<td>260</td>
<td>425</td>
</tr>
<tr>
<td>Total Advanced Biofuel</td>
<td></td>
<td>195</td>
<td>139</td>
<td>195</td>
</tr>
<tr>
<td>Cellulosic Biofuel</td>
<td>60%</td>
<td>195</td>
<td>139</td>
<td>195</td>
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<tr>
<td>Cellulosic Ethanol</td>
<td></td>
<td>60</td>
<td>60</td>
<td>60</td>
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<tr>
<td>Cellulosic Diesel</td>
<td></td>
<td>135</td>
<td>79</td>
<td>135</td>
</tr>
<tr>
<td>Biomass-based Diesel</td>
<td>50%</td>
<td>15</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Biodiesel (fame)</td>
<td></td>
<td>23</td>
<td>15</td>
<td>23</td>
</tr>
<tr>
<td>Renewable Diesel</td>
<td></td>
<td>20</td>
<td>13</td>
<td>20</td>
</tr>
<tr>
<td>Other Advanced Biofuel</td>
<td>50%</td>
<td>42</td>
<td>36</td>
<td>42</td>
</tr>
<tr>
<td>Brazilian Sugarcane</td>
<td></td>
<td>25</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Other Biodiesel</td>
<td></td>
<td>18</td>
<td>12</td>
<td>18</td>
</tr>
<tr>
<td>Renewable Fuel</td>
<td>20%</td>
<td>165</td>
<td>165</td>
<td>165</td>
</tr>
<tr>
<td>Total Ethanol</td>
<td></td>
<td>250</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>Total Biodiesel</td>
<td></td>
<td>176</td>
<td>106</td>
<td>176</td>
</tr>
</tbody>
</table>
RFS2 Biofuels: Oregon’s Proportionate Share of Primary Control Case
BAU Ethanol Assumptions

• Quantity
  – Ceiling: Proportionate shares (requires E85)
  – Floor: Oregon rules (E10, no E85)
  – Advisory Committee recommended considering Oregon gasoline station throughput relative to National Average to determine if E85 infrastructure costs would be more or less recoverable than the national average
    - Oregon average throughput = 523 gal/day per station (2007 Census)
    - U.S. average throughput = 489 gal/day per station 2007 Census)
  – Conclude E85 infrastructure cost as recoverable in Oregon as the national average
  – BAU assumes proportional shares of RFS2 Primary Control Case ethanol volumes

• Ethanol Types: Assuming proportionate shares of each ethanol type in RFS2 Primary Control Case (cellulosic, sugarcane, corn)

• Blend Level: Advisory Committee recommended using an E10 blendwall since greater blend levels are not currently allowable
BAU Biodistillate Assumptions

• Biodistillate Volumes
  – Ceiling: Proportionate shares (~ 15% blend by 2022)
  – Floor: Oregon rules (2.7%, assumes 10% in PDX, 2% rest of state)
  – Advisory Committee recommended using RFS2 Primary Control Case proportional shares for the BAU distillate category

• Bio-Distillate Types: Using Proportionate Shares of RFS2 Primary Control Case types (cellulosic, renewable, methyl-esters)
Business-As-Usual Biofuel Consumption

- Ethanol
  - Project Oregon hits E10 Blendwall in 2013
  - Consuming proportional share of RFS2 ethanol volumes requires significant E85
- BD blend level increases to ~13.5% in 2022 (state mandate ~2.7%)
Ethanol Consumption

- Total BAU Ethanol Use is ~ 250 MGY
Biodistillate Consumption

• Primary Control case biodistillate volumes
• Except for cellulosic diesel – delayed use until 2013
BAU Assumptions & Results

BAU Carbon Intensity

Carbon Intensity (g/MJ)

- Gasoline Pool
- Diesel Pool
- One Pool

Reduction
- 2.7%
- 4.0%
- 5.8%
## Gasoline Pool VISION Results

### Gasoline Pool Matrix

<table>
<thead>
<tr>
<th>Units</th>
<th>Run 1</th>
<th>Run 2</th>
<th>Run 3</th>
<th>Run 4</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethanol Blend Level</td>
<td>% vol</td>
<td>10%</td>
<td>Up to 15%</td>
<td>10%</td>
</tr>
<tr>
<td>Ethanol Volumes</td>
<td>MGY</td>
<td>At least BAU</td>
<td>At least BAU</td>
<td>At least BAU</td>
</tr>
<tr>
<td>OR Corn</td>
<td>MGY</td>
<td>26</td>
<td>26</td>
<td>26</td>
</tr>
<tr>
<td>OR Waste Food</td>
<td>MGY</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>OR Farmed Trees</td>
<td>MGY</td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>Avg MW Corn</td>
<td>MGY</td>
<td>Balance to achieve E10</td>
<td>Balance to achieve E10</td>
<td>Balance to achieve E10</td>
</tr>
<tr>
<td>Low CI MW Corn</td>
<td>MGY</td>
<td>0</td>
<td>Up to RFS2 Share</td>
<td>Up to RFS2 Share</td>
</tr>
<tr>
<td>Brazil Sugarcane</td>
<td>MGY</td>
<td>0</td>
<td>Up to RFS2 Share</td>
<td>Up to RFS2 Share</td>
</tr>
<tr>
<td>Cellulosic</td>
<td>MGY</td>
<td>Balance to achieve CI goal</td>
<td>Up to Share of RFS2 Max EtOH</td>
<td>Low to Moderate (up to 194)</td>
</tr>
<tr>
<td>Vehicle Population</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>E85 FFV</td>
<td>1000’s</td>
<td>BAU</td>
<td>Increase if % E85 VMT is high</td>
<td>BAU</td>
</tr>
<tr>
<td>EVs &amp; PHEVs</td>
<td>1000’s</td>
<td>BAU</td>
<td>BAU</td>
<td>240-288</td>
</tr>
<tr>
<td>Light Duty CNG</td>
<td>1000’s</td>
<td>BAU</td>
<td>BAU</td>
<td>BAU</td>
</tr>
<tr>
<td>Med Duty CNG</td>
<td>1000’s</td>
<td>1.2*BAU</td>
<td>1.2*BAU</td>
<td>1.2*BAU</td>
</tr>
<tr>
<td>E85 Use</td>
<td>% VMT</td>
<td>Float as needed to consume ethanol</td>
<td>Float as needed to consume ethanol</td>
<td>Float as needed to consume ethanol</td>
</tr>
</tbody>
</table>
## Assumed Oregon Ethanol Available Supplies

<table>
<thead>
<tr>
<th>Ethanol Type</th>
<th>Supply (MGY)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW Corn</td>
<td>unlimited</td>
<td></td>
</tr>
<tr>
<td>Low CI MW Corn</td>
<td>32 / 3,000</td>
<td>RFS2 Proportional Share / National Supply - 2022</td>
</tr>
<tr>
<td>Boardman Corn</td>
<td>26</td>
<td>Pacific Ethanol (2/3 of capacity)</td>
</tr>
<tr>
<td>Boardman Farmed Trees</td>
<td>0.25</td>
<td>Zeachem Plant</td>
</tr>
<tr>
<td>Oregon Waste Food</td>
<td>1.5</td>
<td>Summit Natural Energy</td>
</tr>
<tr>
<td>Oregon Wheat Straw</td>
<td>34</td>
<td>Max Potential including canola rotation</td>
</tr>
<tr>
<td>Oregon Cellulosic</td>
<td>171</td>
<td>Forest residue, grass straw, etc¹</td>
</tr>
<tr>
<td>Brazil Sugarcane</td>
<td>24.6 / 2,240</td>
<td>RFS2 Proportional Share / National Supply - 2022</td>
</tr>
</tbody>
</table>

## Gasoline Pool Carbon Intensities (g/MJ)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Direct</th>
<th>ILUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wheat Straw Ethanol</td>
<td>21</td>
<td>0</td>
</tr>
<tr>
<td>Waste food, Forest Residue, Grass waste</td>
<td>21</td>
<td>0</td>
</tr>
<tr>
<td>Farmed Trees</td>
<td>16</td>
<td>5</td>
</tr>
<tr>
<td>Oregon Corn Ethanol</td>
<td>57</td>
<td>30</td>
</tr>
<tr>
<td>Midwest Corn Ethanol</td>
<td>65</td>
<td>30</td>
</tr>
<tr>
<td>Brazilian Sugarcane Ethanol</td>
<td>26</td>
<td>46</td>
</tr>
<tr>
<td>Low-carbon Midwest Corn Ethanol</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Electricity (value shown has no EER applied)</td>
<td>155</td>
<td>0</td>
</tr>
<tr>
<td>CNG</td>
<td>71</td>
<td>0</td>
</tr>
</tbody>
</table>

Electricity EER is 4.1 in 2010, decreasing to 3.1 in 2022. Results in carbon intensity ranging from 38 to 50 g/MJ.
Run 1 (In-State Cellulosic with ILUC)

- Share of FFV Miles on E85 ~ 60%
- Assumes E10 is max amount of ethanol blended into gasoline
Run 1 (In-State Cellulosic with ILUC)

- Ethanol Consumption ~ 307 MGY by 2022
Gasoline Pool VISION Results

Run 1H (Out-of-State Cellulosic with ILUC)

- Share of FFV Miles on E85 ~ 60%
- Assumes E10 is max amount of ethanol blended into gasoline
Run 1H (Out-of-State Cellulosic with ILUC)

- Ethanol Consumption ~ 308 MGY by 2022
Run 2 (Mixed with ILUC)

- Cap E85 Share of FFV Miles at 70%
- If do not ~double population of FFVs,
  - Must increase gasoline blend level to consume ethanol volumes.
Run 2 (Mixed with ILUC)

- Ethanol Consumption ~ 400 MGY by 2022
Run 3 (Mixed without ILUC)

- Share of FFV Miles on E85 ~ 40%
- Adjusted blend level to match Run 2
Run 3 (Mixed without ILUC)

- Ethanol Consumption ~ 330 MGY
  - With lower CI (no ILUC), need 75 MGY less ethanol than Scenario 2
Run 4 (Max EVs + Cellulosic Ethanol with ILUC)

- Share of FFV Miles on E85 ~ 50%
- Assumes E10 is max amount of ethanol blended into gasoline
Run 4 (Max EVs + Cellulosic EtOH with ILUC)

- Ethanol Consumption ~ 280 MGY in 2022
- With high EV penetration, reduce Ethanol by ~ 30 MGY compared to Run 1
Run 4 (Max EVs + Cellulosic Ethanol with ILUC)

- 6x BAU market share to get to 240,000 plug-in vehicles by 2022
- Maintain EV:PHEV market share ratio at 1:6 for all years (meets ZEV)

### Gasoline Pool VISION Results

#### Run 4 – EV/PHEV Populations

![Graph showing EV/PHEV populations from 2010 to 2022 with different vehicle types and their populations over the years.

<table>
<thead>
<tr>
<th>Year</th>
<th>PHEV</th>
<th>EV</th>
<th>Total PHEV/EV</th>
<th>Total Light Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>172,012</td>
<td>29,532</td>
<td>201,544</td>
<td>1,399,968</td>
</tr>
<tr>
<td>2012</td>
<td>197,820</td>
<td>34,132</td>
<td>232,952</td>
<td>1,496,378</td>
</tr>
<tr>
<td>2014</td>
<td>223,628</td>
<td>48,732</td>
<td>272,360</td>
<td>1,602,737</td>
</tr>
<tr>
<td>2016</td>
<td>249,436</td>
<td>63,332</td>
<td>312,768</td>
<td>1,709,109</td>
</tr>
<tr>
<td>2018</td>
<td>275,244</td>
<td>77,932</td>
<td>352,176</td>
<td>1,815,481</td>
</tr>
<tr>
<td>2020</td>
<td>301,052</td>
<td>92,532</td>
<td>391,584</td>
<td>1,921,853</td>
</tr>
<tr>
<td>2022</td>
<td>326,860</td>
<td>107,132</td>
<td>431,992</td>
<td>2,028,225</td>
</tr>
</tbody>
</table>
Agenda

1. Analysis Overview & VISION Model Prep
2. Business-As-Usual Assumptions & Results
3. Gasoline Pool VISION Results
4. Diesel Pool VISION Results
5. One-Pool VISION Results
Appendix
## Proposed Compliance Scenarios

<table>
<thead>
<tr>
<th>Diesel Pool</th>
<th>Units</th>
<th>Run 6</th>
<th>Run 7</th>
<th>Run 8</th>
<th>Run 9</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Proposed Compliance Scenarios</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Units</th>
<th>Run 6</th>
<th>Run 7</th>
<th>Run 8</th>
<th>Run 9</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Biodiesel Blend Level</strong></td>
<td>%</td>
<td>At least BAU</td>
<td>At least BAU</td>
<td>At least BAU</td>
</tr>
<tr>
<td><strong>OR Waste Oil</strong></td>
<td>MGY</td>
<td>Max Capacity</td>
<td>Max Capacity</td>
<td>Max Capacity</td>
</tr>
<tr>
<td><strong>OR Cellulosic</strong></td>
<td>MGY</td>
<td>Low: up to 79</td>
<td>Low: up to 79</td>
<td>Low: up to 79</td>
</tr>
<tr>
<td><strong>NW Canola</strong></td>
<td>MGY</td>
<td>As needed to achieve reduction</td>
<td>High: up to max available</td>
<td>High: up to max available</td>
</tr>
<tr>
<td><strong>NW Renewable Diesel</strong></td>
<td>MGY</td>
<td>50 MGY Maximum</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>MW Soybeans</strong></td>
<td>MGY</td>
<td>Balance</td>
<td>Balance</td>
<td>Balance</td>
</tr>
<tr>
<td><strong>CNG Consumption</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Biogas Derived</strong></td>
<td>MMBtu</td>
<td>Low to Moderate: up to ½ of unused</td>
<td>Low to Moderate: up to ½ of unused</td>
<td>Low to Moderate: up to ½ of unused</td>
</tr>
<tr>
<td><strong>Pipeline NG</strong></td>
<td>MMBtu</td>
<td>Balance</td>
<td>Balance</td>
<td>Balance</td>
</tr>
<tr>
<td><strong>Vehicle Populations</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Medium Duty CNG</strong></td>
<td>1.2 * BAU</td>
<td>1.2 * BAU</td>
<td>1.2 * BAU</td>
<td>4 * BAU</td>
</tr>
<tr>
<td><strong>Heavy Duty CNG</strong></td>
<td>1.2 * BAU</td>
<td>1.2 * BAU</td>
<td>1.2 * BAU</td>
<td>4 * BAU</td>
</tr>
</tbody>
</table>
## Assumed Oregon Biofuel Available Supplies

<table>
<thead>
<tr>
<th>Biodistillate Type</th>
<th>Supply (MGY)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waste Oil</td>
<td>3.5 / 20</td>
<td>Current Capacity / DEQ projected potential</td>
</tr>
<tr>
<td>NW Canola</td>
<td>29.3</td>
<td>Max available w/o ILUC(^a)</td>
</tr>
<tr>
<td>MW Soybean</td>
<td>Unlimited</td>
<td>Out of State SB</td>
</tr>
<tr>
<td>Renewable Diesel (camelina)</td>
<td>50</td>
<td>Camelina grown in other NW states</td>
</tr>
<tr>
<td>Cellulosic</td>
<td>79 / 112</td>
<td>RFS2 Primary Control Case Fair Share /RFS2 Low Ethanol Case Fair Share</td>
</tr>
<tr>
<td>CNG (LFG)</td>
<td>2.15 / 4.3 Million MMBtu</td>
<td>50% / 100% of Unused Biogas(^b)</td>
</tr>
</tbody>
</table>

\(^a\) - 842,924 Acres outside of Willamette Valley available, 40% of time can grow Canola (2 out of 5 years, yield ~ 90 gal BD/acre  
\(^b\) - Includes Wastewater Treatment, Organic Digesters and Landfill Gas  
http://www.oregon.gov/ENERGY/RENEW/Biomass/resource.shtml#Biogas
## Diesel Pool Carbon Intensities (g/MJ)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Direct</th>
<th>ILUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW Soybean Biodiesel</td>
<td>20</td>
<td>62</td>
</tr>
<tr>
<td>Waste Oil Biodiesel</td>
<td>10</td>
<td>0</td>
</tr>
<tr>
<td>NW Canola Biodiesel</td>
<td>27</td>
<td>0*</td>
</tr>
<tr>
<td>Renewable Diesel from Camelina</td>
<td>29</td>
<td>0*</td>
</tr>
<tr>
<td>Cellulosic Diesel</td>
<td>24</td>
<td>12</td>
</tr>
<tr>
<td>CNG (pipeline NG)</td>
<td>71</td>
<td>0</td>
</tr>
<tr>
<td>CNG (biogas)</td>
<td>11</td>
<td>0</td>
</tr>
</tbody>
</table>

- Assume Canola from Oregon – no ILUC b/c will replace fallow in wheat crop rotation
- Assume Camelina is grown outside of Oregon, replacing fallow in wheat crop rotation – 0 ILUC.
Run 6 (In-State Cellulosic Diesel with ILUC)

- ~ 15% BD blend by 2022 (higher than BAU)
Run 6 (In-State Cellulosic Diesel with ILUC)

- Biodistillate Consumption ~ 116 MGY in 2022
- Biogas derived CNG ~ 17 MGY (diesel gal equiv)
Run 6 (In-State Cellulosic Diesel with ILUC)

- ~ 15% BD blend by 2022 (higher than BAU)
Run 6H (In-State Cellulosic Diesel with ILUC)

- Biodistillate Consumption ~ 116 MGY in 2022
- Biogas derived CNG ~ 17 MGY (diesel gal equiv)
Run 7 (Conventional BD with ILUC)

• ~ 14% BD blend by 2022
Run 7 (Conventional BD with ILUC)

- Biodistillate Consumption ~ 108 MGY in 2022
- CNG derived from biogas ~ 17 MGY (diesel equiv)
Run 8 (Conventional BD without ILUC)

- ~ 13.5% BD blend by 2022
Run 8 (Conventional BD without ILUC)

- Biodiesel Consumption ~ 106 MGY in 2022
- With lower CI, can use mainly soybean BD to satisfy volume and CI requirements
- Very little Bio-CNG needed in 2022
Run 9 (Max Natural Gas, Conventional BD)

- ~ 13.7% BD blend by 2022
Run 9 (Max Natural Gas, Conventional BD)

- 103 MGY biodistillate
- Assumes use of all unused biogas potential (33 MGY diesel equiv)
Agenda

1. Analysis Overview & VISION Model Prep
2. Business-As-Usual Assumptions & Results
3. Gasoline Pool VISION Results
4. Diesel Pool VISION Results
5. One-Pool VISION Results

Appendix
One-Pool Scenario – Constraints

- Set PHEV/EV population at $2 \times \text{BAU}$ (ensuring ZEV compliance)
- No increase in LDD
- Cap Biodistillate volume at fair share
- Cap Ethanol volume at fair share
One-Pool Scenario – Gasoline and Replacements

- Share of FFV Miles on E85 ~ 60%
- Assumes E10 is max amount of ethanol blended into gasoline
One-Pool Scenario

- Ethanol Consumption ~ 300 MGY in 2022
One Pool VISION Results

One-Pool Scenario: Diesel and replacements

- ~ 14.3% BD blend by 2022
One-Pool Scenario – Diesel replacements

- Biodistillate Consumption ~ 113 MGY in 2022
- Bio-CNG Consumption ~ 16 MGY in 2022 (diesel equiv gal)
One-Pool Scenario

• Slightly More Diesel pool reductions than gasoline
Agenda

1. Analysis Overview & VISION Model Prep
2. Business-As-Usual Assumptions & Results
3. Gasoline Pool VISION Results
4. Diesel Pool VISION Results
5. One-Pool VISION Results
6. Consolidated Scenario Results

Appendix
**VISION Runs Combined to Form Scenarios:**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Gasoline Pool Run</th>
<th>Diesel Pool Run</th>
</tr>
</thead>
<tbody>
<tr>
<td>A: Cellulosic Biofuels (In-State)</td>
<td>Run 1</td>
<td>Run 6</td>
</tr>
<tr>
<td>AH: Cellulosic Out of State</td>
<td>Run 1H</td>
<td>Run 6H</td>
</tr>
<tr>
<td>B: Mixed Biofuels with ILUC</td>
<td>Run 2</td>
<td>Run 7</td>
</tr>
<tr>
<td>C: Mixed Biofuels No ILUC</td>
<td>Run 3</td>
<td>Run 8</td>
</tr>
<tr>
<td>D: Technology and cellulosic biofuels</td>
<td>Run 4</td>
<td>Run 9</td>
</tr>
<tr>
<td>E: One Pool</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CH: Mixed, no ILUC, High Oil</td>
<td>Run 3H</td>
<td>Run 8H</td>
</tr>
<tr>
<td>CL: Mixed, no ILUC, Low Oil</td>
<td>Run 3L</td>
<td>Run 8L</td>
</tr>
</tbody>
</table>
Consolidated Scenarios

Change in Fuel Use Relative to BAU

Scenario A

Scenario H (Scen A Out-of-State)

Scenario D

One Pool

Change in Fuel Use Relative to BAU, Trillion Btus

-15 -10 -5 0 5 10 15

-15 -10 -5 0 5 10 15

-15 -10 -5 0 5 10 15

-15 -10 -5 0 5 10 15

Gasoline
Ethanol
Electricity
Diesel
Biodiesel
CNG

Gasoline
Ethanol
Electricity
Diesel
Biodiesel
CNG

Gasoline
Ethanol
Electricity
Diesel
Biodiesel
CNG

Gasoline
Ethanol
Electricity
Diesel
Biodiesel
CNG

Gasoline
Ethanol
Electricity
Diesel
Biodiesel
CNG
Consolidated Scenarios

Change in Fuel Use Relative to BAU (concluded)

Scenario B

Scenario C

Scenario C (High Oil)

Scenario C (Low Oil)
Market Shares of Alternative Fuel Vehicles

- Used VISION defaults for all vehicle types except PHEVS and EVs
  - Doubled EV/PHEV market share
  - Washington HEV shares are double national rate
- Increased ratio of EV:PHEV from default of 1:99 to 1:6
Vehicle Fuel Economy

- VISION model has baseline vehicle fuel economy values over time
  - Light duty baseline vehicle is mid-size gasoline
    - Includes CAFE improvements
    - Similar to Pavley tailpipe GHG standard
  - Medium & Heavy duty baseline vehicles are diesel
- Fuel economy for alternative vehicles are scaled from baseline vehicle with Energy Economy Ratio (EER)
  - Ratio of baseline vehicle MJ/mi to alt vehicle MJ/mi
  - Also used to scale carbon intensity values
- Modifying selected VISION EERs
  - EVs
  - PHEVs (electric portion)
  - Light duty diesel
  - Light duty CNG
  - HD CNG (added)
PHEV and EV EERs

- TIAX adjusted the VISION default EER for EVs and the electric portion of PHEVs
  - Increased 2010 EV fuel economy to CARB value
  - Assume no EV fuel economy improvement through 2022

<table>
<thead>
<tr>
<th>Light Duty Vehicles</th>
<th>Units</th>
<th>VISION Default</th>
<th>CARB</th>
<th>Assumption for Washington</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline Vehicle</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>mi/gal</td>
<td>30.0</td>
<td>29</td>
<td>30.0</td>
</tr>
<tr>
<td>2020</td>
<td>mi/gal</td>
<td>38.8</td>
<td>38</td>
<td>38.8</td>
</tr>
<tr>
<td>2022</td>
<td>mi/gal</td>
<td>38.9</td>
<td>X</td>
<td>38.9</td>
</tr>
<tr>
<td>PHEV/EV</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>MJ/mi</td>
<td>1.0</td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>mi/gal</td>
<td>83</td>
<td>119(^a)</td>
<td>122(^b)</td>
</tr>
<tr>
<td>2020/2022</td>
<td>mi/gal</td>
<td>108</td>
<td>119(^a)</td>
<td>122(^b)</td>
</tr>
<tr>
<td>PHEV/EV EER</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td></td>
<td>2.8</td>
<td>4.2</td>
<td>4.1</td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td>2.8</td>
<td>3</td>
<td>3.1</td>
</tr>
</tbody>
</table>

a. Converted to mi/gal using GREET default LHV for CARFG of 113,927 Btu/gal
b. Converted to mi/gal using GREET default LHV for conventional gasoline of 116,090 Btu/gal
Other EER Adjustments

• Light Duty Diesel
  – The VISION default EER for light duty diesel vehicles is constant over time at 1.3, resulting in a fuel economy of over 50 mpg in 2025.
  – TIAX adjusted the EER to reflect improvements to the gasoline vehicle through 2018 that will not translate to diesel vehicles
    - Use the default value of 1.3 in 2010
    - Decrease to 1.1 by 2018
  – The light duty diesel EER is applied to the diesel carbon intensity value in Scenario F only (One-Pool Scenario)

• Light Duty CNG
  – The default EER was 0.96.
  – TIAX revised to 1.0 reflect the Honda civic GLX
  – Consistent with CARB LCFS analysis

• Medium/Heavy duty CNG EER
  – This category was not included in VISION
  – TIAX utilized an EER of 0.90 based on the Cummins Westport ISLG engine
  – Consistent with CARB LCFS analysis
Light Duty Fuel Economy Summary

![Bar chart showing fuel economy comparison between 2010 and 2022 for various types of vehicles: Gasoline, Updated EV, E85 FFV, Updated Diesel, CNG, Gasoline HEV, and PHEV.](chart.png)
Medium and Heavy Duty Fuel Economy Summary

- VISION has slight increases in heavy duty vehicle fuel economy
Appendix: VISION Inputs

Vehicle Prices

- VISION default price increments utilized
- EV increment consistent with current Leaf pricing
- Battery cost projections may lead to lower EV price differentials by 2020
- This seems to be a conservative economic assumption
Appendix: VISION Inputs

Fuel Prices

Gasoline and Ethanol – Used AEO2010 Pacific Prices

Motor Gasoline Price, $/gal

E85 Price, $/gal
Diesel and Biodiesel Prices

- For Diesel, using AEO2010 Pacific forecast
- For Biodiesel, using diesel price + $0.63
  - EIA does not forecast BD prices
  - U.S. DOE EERE data indicate a 5 year average price differential of $0.63
Electricity Prices

- Compared Oregon retail electricity prices to U.S. average prices.
- Seven year average of ratio of OR to U.S. prices is 78%
- Applied 78% factor to AEO2010 U.S. price

Oregon Estimate is 78% of AEO2010 U.S. forecast.
CNG Prices

- Using AEO2010 Pacific Forecast
Include Affected Off-Road Diesel Consumption

- Off-Highway
  - Construction, Mining
  - Assume 90% of this category
- Railroad
  - Intrastate estimated at 6,385 thousand gal/yr*
  - Corresponds to 8% of category
- Vessel Bunkering
  - All commercial and private
  - Assume 50% of this category
- Assumptions result in
  - 538.7 Million gal/yr on-road
  - 41.9 Million gal/yr non-road
  - Non-road/(on-road+non-road) = 7.2%
- Add off-road diesel consumption to VISION with multiplier of 1.072

Source: EIA Oregon Distillate Use Data

Appendix G: Indirect Land Use Change Comparative Analysis

Oregon Low Carbon Fuel Standards Report
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4.0 Conclusions and Recommendations ............................................................................ 17
1.0 Introduction

The concept of biofuels used in the transportation sector inducing indirect greenhouse gas emissions through changes in land use around the world came to the forefront of environmental policy in late 2007 and early 2008 with the publication of several articles in Science Magazine\(^1\). These indirect emissions are referred to as indirect land use change (ILUC) emissions. ILUC emissions arise when an existing crop is diverted for another purpose such as transportation fuel production. To replace the diverted crop, something else is planted somewhere else. If the replacement crop is planted on land that had previously not been used as cropland, then some amount of carbon might be liberated as a result of bringing that land under cultivation (e.g. removing a forest to plant replacement soybeans).

The Oregon Department of Environmental Quality (DEQ) is currently developing a LCFS. TIAX has been tasked by DEQ to compare the various ILUC calculation methods, assumptions, and results for corn ethanol, soybean biodiesel, and sugarcane ethanol and to make a recommendation as to how Oregon DEQ should incorporate ILUC emissions into the carbon intensity estimates of the fuels complying with its LCFS and what values should be utilized in Oregon’s LCFS.

The balance of this report provides a comparison of the predominant ILUC analyses performed to date. The methodologies and major assumptions are compared and the results for corn ethanol, sugarcane ethanol and soybean biodiesel are presented. Finally, some conclusions and a recommendation regarding inclusion of ILUC in the Oregon LCFS carbon intensity estimates are provided.

2.0 Comparison of Analyses

We considered three separate analyses of ILUC emissions and then describe a reinterpretation of the EPA analysis by the Renewable Fuels Association. The specific analyses considered are:

2.0.1 US Environmental Protection Agency (EPA) Analysis

Estimates developed for RFS2 using a combination of the FASOM and FAPRI agricultural models, CENTURY soil emission model and Winrock International land use change emission factors

2.0.1.1 Renewable Fuels Association (RFA)

RFA reinterpreted the EPA RFS2 results. The derivation of the RFA values is documented in a letter sent to U.S. EPA Administrator Lisa Jackson which utilized EPA’s results determined for the RFS2

2.0.2 California Air Resources Board (CARB) Analysis

Estimates developed for the California LCFS using a combination of the Global Trade Analysis Project (GTAP) economic model and Woods Hole Research Institute land use change emission factors

2.0.3 Purdue University and GTAP (Purdue/GTAP) Analysis

These values were determined with an updated version of the GTAP model and Woods Hole Research Institute land use change emission factors

For much of the following discussion, the inputs, elasticities and values for corn ethanol will be used as a surrogate for the other fuels as the same methodologies were employed in modeling all of the fuels. The modeling approaches are significantly different as are the values for many assumptions. We provide here a comparison of:

- General Modeling Methodologies
- Land Use Change Estimates (how much land, where, what was prior use)
- Elasticity Assumptions
- Co-Product Assumptions
- Emission Factors and Sequestration

It is difficult, and therefore we have not attempted, to prioritize and rank the significance of the above attributes to the resulting ILUC emission estimates in each of the analyses.

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2 US Federal Register, Volume 75, No. 58, Friday March 26, 2010, pg 14769-14818
3 Letter from Bob Dineen, CEO and President of Renewable Fuels Association, addressed to U.S. EPA Administrator Lisa Jackson on August 4, 2010.
4 California Code of Regulations, Title 17, Subchapter 10, Subarticle 7 Section 95480-95490.
2.1 General Modeling Methodologies

In this subsection we will discuss the differences between the general models used for the determination of the quantity of land that is changed by biofuels. In later sections we will discuss the how the reports and models vary between the conversion of land changed to greenhouse gas (GHG) emissions.

Regardless of the specific models used and assumptions made to determine the effect of ILUC, the general methodology for estimating ILUC GHG emissions is illustrated in Figure 1. First, an assumption is made about how much transportation fuel is to be produced and which feedstock will be used. This results in a specified amount of an existing crop being diverted to a new purpose. The next step is to determine which type or types of crops will be used to compensate for the shortfall in the diverted crop, and how much of the new crop/crops will be required, and in what country/region will these new crops be grown.

Once the crop type(s), quantity and location are defined, the prior use of the land upon which these replacement crops are grown must be determined. Once this is decided, an appropriate emission factor is selected and applied to estimate the GHG emissions from changing the use of the land. The result at this point in the analysis is an estimate of the tons of CO2 emissions liberated due to diverting a crop to transportation fuel production. This total is then divided by the MJ of fuel produced from the diverted crop – a g/MJ estimate. However, the carbon emissions associated with changing the land need to be amortized over a suitable period of time. For example, if the new land is cultivated for 30 years, then it may be appropriate to divide the total g/MJ estimate by 30 years.

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**Figure 1. Schematic of General ILUC Emission Estimate Methodology.**
2.1.1 EPA Analysis

U.S. EPA worked on transportation fuel lifecycle GHG emissions in support of a revision to the Renewable Fuel Standard mandated by EISA. The revised standard, referred to as RFS2, was finalized in February 2010. The RFS2 requires specific volumes of different categories of biofuels be consumed; each biofuel category has a minimum GHG emission reduction relative to petroleum including ILUC emissions. EPA developed their ILUC emission estimates using the Forestry and Agricultural Sector Optimization Model (FASOM) and the Food and Agricultural Policy Institute (FAPRI) model partial equilibrium economic models of the agriculture sector. They are partial equilibrium models because they only include the agricultural part of the world economic sectors and not all sectors.

FASOM was developed in 1996 by the Department of Agriculture to model the U.S. forest and agricultural sectors. FAPRI was developed in 1984 with funding from the U.S. Congress by researchers at Iowa State University and the University of Missouri Columbia. FAPRI has been used since the 1980s to develop projections of the U.S. agricultural market and international commodity markets. Both the FASOM and FAPRI models have been used extensively to support agricultural sector policy.

FASOM can be used to project domestic land use impacts while FAPRI can be used to quantify international land use impacts. FASOM and FAPRI are net agricultural models that estimate the global response to changes in biofuel consumption across agricultural sectors. Specifically, the models are used to determine the quantity and location of land changed due to diversion of crops to biofuel production. For example, the models can be used to estimate a response to increased corn ethanol production in the United States. The models project domestic and international reactions in the agricultural and livestock sectors to determine types and quantities of crops substituting for corn, the location and number of acres needed to produce the replacement crops, and the impact on livestock population.

FASOM and FAPRI are partial equilibrium models; their combined results determine the total land use change. Although the two models are not automatically interconnected, the FASOM outputs are used as inputs to the FAPRI model. Each model independently reaches equilibrium, and since they are not interconnected, values such as U.S. exports and import quantities and agricultural prices may not match at the end of the model runs. While FASOM determines the amount of land changed and subsequent GHG emissions internally, FAPRI only predict the amount of land use change and location – prior use of the land and the subsequent GHG emissions associated with changing its use are quantified outside of the FAPRI model.

FASOM and FAPRI have beginning and end years for the analysis, and in EPA’s RFS2 analysis, the start year is 2010 and the end year is 2022. EPA ran a baseline case without RFS2 and a control case with all the projected RFS2 biofuel volumes increased. To determine the land use impact of each individual fuel type (corn ethanol, sugarcane

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ethanol and soybean biodiesel), EPA also ran cases in which the volumes of these fuels were altered while all other biofuel volumes stayed constant.

Most recently, the Renewable Fuels Association (RFA) wrote a letter to U.S. EPA Administrator Lisa Jackson asserting that the RFS2 ILUC values are grossly overstated. RFA points out that EPA’s Control Case in which simultaneous increases of all biofuels results in less ILUC than the sum of the ILUC value determined when modeling each individual fuel separately. The ILUC values assigned to each fuel are taken from the individual fuel model runs. RFA believes that the ILUC values assigned to each fuel should be scaled back so that the sum of the individual fuel ILUC values equals the total ILUC value from EPA’s Control Case.

2.1.2 CARB Analysis
In early 2008, the California Air Resources Board (CARB) was in the initial stages of developing its Low Carbon Fuel Standard (LCFS). The goal of CARB’s LCFS is to achieve a 10 percent reduction in transportation fuel carbon intensity by 2020. The carbon intensity of each fuel includes well-to-wheel direct emissions and emissions associated with indirect land use change (ILUC). CARB and the researchers at Purdue University performed an analysis utilizing the Global Trade Analysis Project (GTAP) equilibrium economic model. CARB published draft and revised estimates of ILUC GHG emissions for corn ethanol, sugarcane ethanol, and soybean biodiesel through February of 2010. Upon adoption of the LCFS in April 2010, CARB was required to convene an Expert Workgroup to “refine and improve” the ILUC analysis and provide recommendations to address any issues identified by January 1, 2011.

GTAP is a global general equilibrium (meaning it contains all economic sectors) model that assesses the economic impacts of changes in biofuel production and the subsequent land use change by region and Agro Ecological Zone (AEZ). The AEZs in GTAP share common climate, precipitation and moisture conditions. The version of GTAP used in the CARB analysis is GTAP-6, based on economic conditions in 2001.

Consistent with the FAPRI (international) section of the EPA analysis, GTAP is used to determine land use change (quantity and location) with prior land use and emission factors applied outside the model. The CARB methodology differs from the EPA methodology in that the modeling is based on current conditions with a 2015 analysis year, versus a 2022 year for EPA. Each of the fuels is modeled separately with a shock in fuel consumption that is expected to occur between 2001 and 2015, while all of the economic conditions are constant. There is no baseline or reference case to compare against in the CARB methodology.

One major concern with the CARB methodology is that there is no interaction between different agricultural sectors. For example, when modeling an increase in U.S. corn ethanol consumption, changes in other agricultural sectors, such as soybeans or livestock, are not taken into account. Moreover, the CARB methodology does not include conservation reserve program (CRP) land as an available land type for production of
crops to replace the diverted biofuel feedstock crop. Many experts believe that CRP land would be one of the first land types converted with the expansion of biofuel production.

2.1.3 Purdue/GTAP Analysis

In July of 2010, the researchers at Purdue University made major changes to the GTAP model to more accurately model ILUC. A new analysis for corn ethanol was published in July of 2010 showing significantly lower emissions than the previous estimate in the CARB analysis. No new values for sugarcane ethanol or soybean biodiesel have been developed or published.

The Purdue/GTAP analysis varies significantly from the earlier CARB analysis even though they both use the GTAP model. For this analysis, a new module was added to the GTAP model; the modified model is referred to as GTAP-BIO-ADV. The updated GTAP model now takes into account crop pasture land in the US and Brazil, and has added CRP land inside the United States. Interactions between agricultural industries, specifically livestock, were added in addition to substitutability between biofuels and petroleum products and interactions between biofuel intermediate and co-products and the rest of the agricultural industry. Finally, the GTAP-BIO-ADV has been updated to take into account 2006 world economic conditions.

The Purdue/GTAP methodology also utilizes a baseline or reference case to compare the full biofuel expansion against. This reference case accounts for annual increases in crop yield and population growth, as a surrogate for crop demand growth. Another significant change between the Purdue/GTAP and CARB analyses is that Purdue/GTAP modeled incremental changes of 2 billion gallons in annual biofuel consumption culminating at 15 billion gallons per year (BGY) (these increments were used as surrogates for time intervals). The outputs from the previous 2 billion gallon increase were used as inputs to the next 2 billion gallon per year increment, thereby updating the economic conditions, something that was not done in the CARB analysis. Figure 2 below shows a timeline of the above ILUC analyses.
<table>
<thead>
<tr>
<th>Year</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 2007</td>
<td>CARB Expert Workgroup Results</td>
</tr>
<tr>
<td>January 2008</td>
<td>Searchinger and Fargione Papers</td>
</tr>
<tr>
<td>January 2009</td>
<td>CARB ILUC Analysis (GTAP)</td>
</tr>
<tr>
<td>January 2010</td>
<td>EPA ILUC Analysis (FASOM/FAPRI)</td>
</tr>
<tr>
<td>January 2011</td>
<td>Purdue Revised GTAP Analysis</td>
</tr>
<tr>
<td></td>
<td>RFA Re-Analysis of EPA Results</td>
</tr>
<tr>
<td></td>
<td>CARB Expert Workgroup Results</td>
</tr>
</tbody>
</table>

Figure 2. Approximate Timeline of Recent ILUC GHG Emission Estimate Efforts.
2.2 Land Use Change Estimates

Each of the analyses uses very different methods of determining the amount and type of land that the replacement crops are grown on due to diversion of corn, soybean and sugarcane to biofuel production. Not only does the quantity of land, but the type of land have a significant impact on the ILUC emissions estimate as different land types have varying amounts of above and below ground soil carbon that are released when converted to agricultural land.

2.2.1 EPA Analysis

In the EPA methodology, increases in corn ethanol, soybean biodiesel and sugarcane ethanol are modeled simultaneously. FASOM directly determines the amounts and kind of land that is changed within the U.S., and directly calculates the U.S. ILUC GHG emissions. The types of land FASOM selects from include cropland pasture, forest pasture, rangeland, forestland, developed land, and CRP land. For international land use FAPRI determines the amount of land that must be utilized, but does not identify what type of land. To determine the type or prior use of the land converted to produce the replacement crops, EPA utilized satellite data of land use changes from 2001 to 2007 and applied this pattern of land use change to the amount determined in each country. One concern with this methodology is that the land use patterns determined in the satellite data can not be fully attributed to biofuel expansion. Further, it is not clear whether 2001-2007 average land use change should be applied to future crop expansion.

Another concern with the EPA analysis is how the ILUC was determined for the individual fuels. EPA performed modeling assuming simultaneous increases in volumes of all biofuels needed for compliance with RFS2. When modeled together the interrelationship between all of the crops is captured. The result of this model run was used to estimate the impact of RFS2. However, this result was not utilized to determine the ILUC emissions for each individual type of biofuel. EPA estimated the ILUC for each type of the biofuels with independent model runs in FASOM and FAPRI. Table 1 provides EPA’s estimate of total international hectares of land use change due to anticipated RFS2 biofuel volumes. When increases of all RFS2 fuel volumes were modeled simultaneously, a total of 794 thousand hectares of land is needed for the replacement crops. The table also shows that when each fuel was modeled separately holding the other fuels constant, the total amount of land use changed is 1863 thousand hectares; more than double the amount of land use change when all of the biofuels were modeled together. Therefore EPA’s ILUC estimates for the individual fuels may be overstated. This is the essence of RFA’s letter to EPA which is discussed further below.

In RFA’s reinterpretation of EPA’s results, it was assumed that the total amount of land use changed due to the RFS2 is the result from the case in which increases in all fuels are modeled simultaneously. To determine the impact of each individual fuel, RFA simply proportionally allocated the total land use change to the three fuels based on the amount of land use changed in their individual model runs.
Table 1 – EPA International ILUC Estimates for Single Fuel Runs and the Simultaneous Run

<table>
<thead>
<tr>
<th>Thousand Hectares</th>
<th>Soybean Biodiesel Only</th>
<th>Corn Ethanol Only</th>
<th>Brazilian Sugarcane Ethanol Only</th>
<th>Total of Individual Runs</th>
<th>All RFS2 Biofuels Together</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Use Change</td>
<td>678.4</td>
<td>789.3</td>
<td>395.4</td>
<td>1,863.1</td>
<td>794.4</td>
</tr>
</tbody>
</table>

2.2.2 CARB Analysis

In the CARB analysis, GTAP determines the amount and type of land use change inside and outside of the United States. GTAP determines the type of land converted to agriculture based upon the cost to rent land in each of the AEZs. The model is set up as if a “manager” in each AEZ is trying to maximize profits in addition to producing the necessary amounts of biofuels in each region. There is no historical or empirical data used to determine the ratio of forest to pasture land, nor is the cost of preparing non-agricultural land for farming considered. A significant limitation in this analysis is that the only types of land available are pasture land and forests; domestic CRP land and international crop-pasture (dormant crop) land are not an option for the “manager”.

2.2.3 Purdue/GTAP Analysis

The recent Purdue/GTAP analysis uses the same “manager” methodology maximizing rents in each AEZ as in the CARB analysis, except it now includes CRP and crop-pasture land. This is a significant improvement in the quantification of land use to replace diverted corn, soybean and sugarcane.

Table 2 compares the total domestic and international land use change, quantity of biofuel, and estimated acres of land use change due to the increase in biofuel production. The values shown are for corn ethanol. There is a wide range in the amount of land use change estimated per unit of corn ethanol production.

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7 US EPA Renewable Fuel Standard 2 – Regulatory Impact Analysis, pg 427, Table 2.7-3
### Table 2 – Comparison of Land Use Change Quantities for Corn Ethanol Production

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Land Use Change Location</th>
<th>Quantity (million acres)</th>
<th>Ethanol Volume Increase (Billion gal)</th>
<th>Acres/1000 gal of ethanol</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA</td>
<td>U.S.</td>
<td>1.40</td>
<td>2.7</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>ROW&lt;sup&gt;8&lt;/sup&gt;</td>
<td>1.94</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>3.34</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CARB</td>
<td>U.S.</td>
<td>3.85</td>
<td>13.25</td>
<td>0.7</td>
</tr>
<tr>
<td></td>
<td>ROW</td>
<td>5.75</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>9.61</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purdue/GTAP</td>
<td>U.S.</td>
<td>1.04</td>
<td>13.23</td>
<td>0.32</td>
</tr>
<tr>
<td></td>
<td>ROW</td>
<td>3.22</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>4.26</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RFA</td>
<td>U.S.</td>
<td>1.55</td>
<td>2.7</td>
<td>0.88</td>
</tr>
<tr>
<td></td>
<td>ROW</td>
<td>0.83</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>2.38</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 2.3 Elasticity Assumptions

There are many assumptions made within the GTAP and FASOM/FAPRI models. Two key assumptions have significant impact on the amount of land needed to cultivate replacement crops for the crops diverted into biofuel production. These two assumptions are the price/yield elasticity and the new land yield elasticity. Price/yield elasticity is the amount of increase in crop yield (e.g. bushels per acre) that will result from an increase in the market price for that crop. For example, a price/yield elasticity of 0.5 means that a price increase of 1% would result in a yield increase of 0.5%. A higher the price/yield elasticity equates to a reduction in the amount of land necessary to replace the displaced crop and therefore a reduction in ILUC emissions.

The new land elasticity is a ratio of new land yield to current land yield. For example, a new land elasticity value of 0.6 means that new land is only 60% as productive as current land. The lower the elasticity, the more acres of land that will be needed to produce replacement crops resulting in an increase in ILUC emissions.

#### 2.3.1 Price/Yield

In the EPA analysis, FASOM and FAPRI have different price/yield elasticities. FASOM has a value of 0 while FAPRI has short term and long term elasticities. The short term is defined as the percent change in yield due to a one-year increase in price while the long term elasticity is defined as the percent change in yield due to a permanent (10 year average) change in price. For corn, the short-term and long-term elasticities in FAPRI are 0.013 and 0.074.

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<sup>8</sup> ROW – Rest of World
The CARB analysis utilized a single price/yield elasticity of 0.32 which is significantly higher than the values used by EPA. The Purdue/GTAP methodology utilized a price/yield elasticity of 0.25, still significantly higher than the EPA methodology.

2.3.2 New Land Yield

There is also a wide variation in new land yield elasticities (Table 3). EPA and CARB assume constant new land elasticity for all regions and land types. The FAPRI elasticity units are slightly different where the percent change in yield (-0.023%) of the total area of a country due to a 1% increase in total area. For example, a 10% increase in land would result in a -0.23% yield for the total area. This is not directly comparable to the FASOM and GTAP elasticity values. The Purdue/GTAP new land elasticity values vary by region and land type. These values were obtained from the Terrestrial Ecosystem Model and vary widely; most of the values are higher than 0.66 (the CARB value), and are between 0.8 – 1.0.

<table>
<thead>
<tr>
<th>Report</th>
<th>New Land Yield Elasticity</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPA (RFA)</td>
<td>FASOM – 1.0</td>
</tr>
<tr>
<td></td>
<td>FAPRI – -0.023*</td>
</tr>
<tr>
<td>CARB</td>
<td>0.66</td>
</tr>
<tr>
<td>Purdue/GTAP</td>
<td>Varies by Region and Land type, range of 0.49-1.0</td>
</tr>
</tbody>
</table>

*Value not directly comparable

2.4 Co-Product Assumptions

The recognition of co-products and interaction between agricultural industries has a significant impact on the quantity of land use changed due to increases in biofuel production. For example, in producing corn ethanol with the dry mill process, dry distillers grains and solubles (DGS) is co-produced. The DGS is used as animal feed. In the CARB analysis, one pound of DGS displaces one pound of corn feed for cattle (dairy and beef), swine and/or poultry. This displacement reduces the amount of corn farming. The reduced farming is taken as an energy credit when calculating corn ethanol direct carbon intensity with the GREET model. The reduced farming also gets a credit in the land use change calculation (less land needed for corn production). In the CARB analysis, there are no interactions between agricultural industries, so the DGS cannot displace soybean meal (a soybean biodiesel production co-product).

2.4.1 EPA Analysis

In the EPA methodology (and the RFA) interactions between agricultural industries are captured, so DGS displaces some soybean meal in the cattle dairy, swine and poultry industries. The EPA analysis assumes that DGS displaces 1.3 pounds of agricultural products. Of the 1.3 pounds, approximately 1.2 lbs of corn are displaced and approximately 0.1 lb of soybean meal is displaced. The soybean meal displacement has a large impact on land use change since soy has much lower yields per acre than corn. Therefore, the EPA assumptions result in less land use change than the CARB assumptions.
In addition to distiller’s grains, EPA assumes 90% of dry mills in 2022 will extract corn oil from distiller grains. This corn oil has additional displacement for soybean oil that is used to produce soybean-derived biodiesel.

2.4.2 CARB Analysis
In the CARB analysis, one pound of DGS displaces one pound of corn feed for cattle (dairy and beef), swine and/or poultry. CARB does not assume the separation of corn oil from distiller’s grains.

2.4.3 Purdue/GTAP Analysis
For the Purdue/GTAP analysis, though substitution rates are not explicitly mentioned in the report, the updated model does allow interactions between agricultural sectors and DGS does substitute for some amount of soybean meal. This substitution results in a decrease in the amount of land use change relative to the CARB analysis.

2.5 Emission Factors and Sequestration
Once the amount and type of land use change has been determined, the GHG emissions associated with converting the land must be selected and applied in addition to the amount of carbon sequestered. Higher emission factors and lower sequestration factors result in increased ILUC emissions.

2.5.1 Emission Factors
Two different sources of emission factors are available: Winrock International and Woods Hole Research Institute. The EPA analysis utilized Winrock International emission factors while the CARB and Purdue/GTAP analyses utilized the Woods Hole Research Institute data. These data sets vary in that Winrock International factors are by region within a country while the Woods Hole data is by land type within a region. Direct comparisons are therefore difficult.

Tables 4 and 5 show data for Brazil (Woods Hole values are for Latin America which includes Brazil) from Winrock and Woods Hole where general comparisons can be made.9 It appears that on average the Winrock International emission factors are lower than the Woods Hole emission factors.

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Table 4 - Winrock International CO₂ Above Ground Emission Factors - Brazil

<table>
<thead>
<tr>
<th>Region</th>
<th>CO₂, T/Ha</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amazon Biome</td>
<td>606</td>
</tr>
<tr>
<td>Northeast Coast</td>
<td>145</td>
</tr>
<tr>
<td>North-northeast Cerrado</td>
<td>244</td>
</tr>
<tr>
<td>Central-West Cerrado</td>
<td>290</td>
</tr>
<tr>
<td>Southeast</td>
<td>243</td>
</tr>
<tr>
<td>South</td>
<td>225</td>
</tr>
<tr>
<td>Average</td>
<td>292</td>
</tr>
</tbody>
</table>

Table 5 - Woods Hole CO₂ Above Ground Emission Factors - Latin America (Forest)

<table>
<thead>
<tr>
<th>Forest Type</th>
<th>CO₂, T/Ha</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tropical Evergreen Forest</td>
<td>733</td>
</tr>
<tr>
<td>Tropical Seasonal Forest</td>
<td>513</td>
</tr>
<tr>
<td>Tropical Open Forest</td>
<td>202</td>
</tr>
<tr>
<td>Temperate Evergreen Forest</td>
<td>616</td>
</tr>
<tr>
<td>Temperate Season Forest</td>
<td>367</td>
</tr>
<tr>
<td>Average</td>
<td>486</td>
</tr>
</tbody>
</table>

2.5.2 Carbon Sequestration

Carbon sequestration in the context of land use change is the use of wood from land clearing in products or other purposes that would sequester the carbon rather than releasing it to the atmosphere. In the CARB analysis, no such sequestration is considered. In the EPA analysis, no sequestration is assumed for international land use change since it is assumed that forests are largely unmanaged, so burning can occur. For EPA’s domestic land use change, FASOM takes into account carbon sequestration in wood products for domestic forest changes. FASOM tracks the fate of carbon overtime in various industries including wood and paper products, mill residue and fuel wood. FASOM assumes that fuel wood displaces fossil fuels.

In the Purdue/GTAP methodology, it is assumed that 25% of the above ground carbon from forest conversion is sequestered. The underlying assumption here is that a certain amount of international forest land is managed which leads to the use of wood in products or industry.
### 2.6 Summary

Table 6 below is a summary matrix of the ILUC reports discussed in this section.

<table>
<thead>
<tr>
<th></th>
<th>EPA (RFA)</th>
<th>CARB</th>
<th>Purdue/GTAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quantity and Location of Land</td>
<td>FASOM – domestic FAPRI - international</td>
<td>GTAP – 6 Model</td>
<td>GTAP-BIO-ADV</td>
</tr>
<tr>
<td>Changed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cases Considered</td>
<td>Baseline – RFS Each Fuel modeled separately</td>
<td>Individual Fuels</td>
<td>Baseline &amp; Corn Ethanol only</td>
</tr>
<tr>
<td></td>
<td>RFA – All RFS2 fuels together</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price/Yield Elasticity</td>
<td>FASOM – 0</td>
<td>0.32</td>
<td>0.25</td>
</tr>
<tr>
<td></td>
<td>FAPRI: Short-term – 0.013 Long-term – 0.074</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Land Yield Elasticity</td>
<td>FASOM – 1.0 FAPRI – -0.023*</td>
<td>0.66</td>
<td>Varies by Region and Land type, range of 0.49-1.0</td>
</tr>
<tr>
<td>LUC Emission Factors</td>
<td>Winrock International, CENTURY Model</td>
<td>Woods Hole Research Institute</td>
<td>Woods Hole Research Institute</td>
</tr>
<tr>
<td>Sequestration</td>
<td>FASOM – some, LUC dependent FAPRI - none</td>
<td>None</td>
<td>Forest – 25% above ground</td>
</tr>
</tbody>
</table>
3.0 Comparison of Results

Figure 3 shows the results of the different modeling methodologies. The values for all biofuels have extreme variation. Although CARB and EPA have similar values for corn ethanol, this appears to be a coincidence. The methodologies for determining the amount and type of land use change (and the subsequent results) and land use conversion factors are so different that this can be the only conclusion. The RFA reinterpretation of EPA’s results result in approximately 50 percent lower values since the total land use change when EPA modeled all fuel increases simultaneously was about half of the sum of modeling all fuels in isolation.

Figure 3: Results
4.0 Conclusions and Recommendations

With the wide variations in analysis methodologies and results, it is difficult to determine which set of values is the most representative of actual ILUC emissions. We draw the following conclusions:

- The CARB analysis has serious limitations
  - No domestic CRP land, no international dormant cropland
  - Dated agro/economic data
  - No time steps, no baseline
  - No interaction between different sectors of the agriculture industry
- The EPA analysis is more comprehensive than the CARB analysis but still has limitations
  - Use of historic satellite data for future land use change
  - Attribution of all historic land use change to biofuels
  - FASOM/FAPRI are partial equilibrium models
- The GTAP analysis is a full equilibrium model, but it determines land use change based on economics and rent prices, not empirical data
- None of the analyses (except RFA’s reinterpretation of EPA’s results) consider simultaneous increases in a variety of biofuels – each estimated in a vacuum.
- Difficult to determine which set of emission factors is more representative

Despite these shortcomings, the methodologies and tools utilized to estimate ILUC emissions have evolved dramatically over the past several years and there are ongoing efforts to continue improving and refining the assumptions, methods and tools. CARB has convened an Expert Workgroup as part of the California LCFS that will make recommendations on how to improve the GTAP based analysis and “assist CARB in refining and improving the land use and indirect effect analysis of transportation fuels and return to CARB no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.”

The Expert Workgroup has the following subgroups to discuss specific issues related to ILUC and other LCFS issues:
- Elasticity Values
- Co-product Credits
- Land Cover Types
- Emission Factors
- Uncertainty in LUC estimates
- Indirect Effects of Other Fuels
- Comparative and Alternative Modeling Approaches
- Time Accounting
- Food Consumption

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10 “California Air Resources Board Low Carbon Fuel Standard Expert Workgroup Guidelines”
http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/lcfs_ewg_guidelines.pdf
The GTAP model has already been improved, presumably utilizing the Expert Workgroup suggestions, and one of the fuel pathways (corn ethanol) has been published with significantly lower results than the earlier CARB analysis, which is the Purdue/GTAP analysis discussed in this report. Purdue/GTAP is not currently performing a similar analysis for biodiesel from soybeans or ethanol from sugarcane.

Given this changing landscape, it is difficult to recommend specific ILUC GHG values that will not be dated in a year. TIAX recommends that DEQ wait until the CARB Expert Workgroup makes its recommendations (January 1, 2011) and EPA responds to RFA’s suggestion. It is not known at this time when, or even if, EPA will respond to the RFA letter.

If DEQ must define ILUC values now, TIAX recommends using an average of the two published analyses (CARB and EPA). For corn ethanol, TIAX recommends averaging the recent GTAP value (rather than the CARB value) with the EPA value.
Appendix H: Fuels Assessment Discussion Paper
Oregon Low Carbon Fuel Standards Report

Presented for discussion at April 15, 2010 Low Carbon Fuel Advisory Committee Meeting.

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**Purpose**

This document contains a description of some of the alternative fuels that are likely to be used to comply with an Oregon low carbon fuel standard. The purpose of this fuels assessment is to provide background on alternative fuel production, use, and commercialization status which will assist the advisory committee with giving DEQ input on feasible volumes of alternative fuels produced, available, or used between now and 2022. DEQ welcomes additional data or information which will assist with this effort. The goal of the April 15, 2010 low carbon fuel advisory committee meeting is to bound high and low possible amounts of alternative fuels used, so DEQ will be asking the advisory committee for low, medium and high (but feasible) estimates for alternative fuels use in Oregon in 2022.

In giving input on the estimates, it should be considered that alternative fuel use would increase under a low carbon fuel standard above amounts required by existing regulations or predicted by historic increases. There are several pieces of information that can inform our fuel estimates. For example, estimates could be based on:

- Regulations applicable to an alternative transportation fuel or alternative-fueled vehicle, such as the federal Renewable Fuel Standard 2 requirement for biofuels or the Oregon low emission vehicle rule (which will increase the number of electric vehicles on the road);
- Historic increases in alternative fuel use; or
- Evaluating alternative fuel use trends in other countries, states, or areas that use large volumes of an alternative fuel or vehicles can help us identify feasible adoption rates for both light-duty passenger vehicles and medium/heavy-duty vehicle applications. It will be important to examine the context that helped produce the large volume of use of an alternative fuel;
- Predictions of future use;
- Studies and expert evaluation; and
- Compliance scenario methodologies for LCFS used by Washington, East Coast/Mid-Atlantic States, and California.

The estimates of feasible volumes of alternative fuel used in Oregon between now and 2022 will be used to develop compliance scenarios, which will in turn be used in the low carbon fuel standard economic analysis.

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1 Light-duty vehicles include passenger cars and light trucks, including minivans, sport utility vehicles (SUVs) and trucks with gross vehicle weight less than 8,500 pounds.
Advisory Committee Questions

This document is intended to begin the process of generating input from the advisory committee members on the following questions. At the April 15, 2010 meeting, experts on transportation uses of natural gas and electricity, as well as biofuel production, will present information and be available for advisory committee questions. DEQ has made a preliminary estimate of low, moderate and high use for some alternative fuels between now and 2022. DEQ expects to revise these after input from the low carbon fuel advisory committee.

General question: Have we missed any fuels or production processes you think will be used to produce substantial volumes of fuels by 2022? If so, please email Sue Langston with the name of the fuel and production process, a short description of the production process, and the number and location of pilot/demonstration/commercial plants, either in the US or the world. Please note that a fuel does NOT need to be included in this assessment to be included in the Oregon low carbon fuel standard program.

Ethanol questions:

- How many flex fuel vehicles (vehicles that can use either gasoline or ethanol blends up to 85%) are likely to be on the road, given current trends? Please consider low, medium, and high estimates that will be feasible from now through 2022. (For DEQ’s preliminary low and high estimates of flex fuel vehicle use, please see section on Starch- and Sugar-Based Ethanol beginning on page 13)

- When is commercial production of cellulosic ethanol production likely to start? What is the range of volume that will be available, given feedstocks in Oregon and the Pacific Northwest? Please consider low, medium, and high estimates that will be feasible from now through 2022. (For DEQ’s preliminary low and high estimates of cellulosic ethanol availability, please see the section on Cellulosic Ethanol beginning on page 22)

Diesel questions:

- What are likely volumes of biodiesel (FAME) that can be made available, given feedstocks in Oregon and the Pacific Northwest? Please consider low, medium, and high estimates that will be feasible from now through 2022. (For DEQ’s preliminary low and high estimates of biodiesel availability, please see the section on Biodiesel (FAME) beginning on page 30)

- How much 5% biodiesel (B5), 10% biodiesel (B10), 20% biodiesel (B20), 99% biodiesel (B99), and 100% biodiesel (B100), will be used in the future, given current trends? Please consider low, medium, and high estimates that will be feasible from now through 2022 for light-duty passenger car use and medium- and heavy-duty applications. (For DEQ’s preliminary low and high estimates of higher biodiesel blend use, please see the section on Biodiesel (FAME) beginning on page 30)
• What is a reasonable estimate of when **renewable diesel (hydrogenation-derived)** will be fully commercialized and available in OR? What are likely volumes of renewable diesel that can be made available, given feedstocks in Oregon and the Pacific Northwest? Please consider low, medium, and high estimates that will be feasible from now through 2022. *(For DEQ’s preliminary low and high estimates of renewable diesel availability, please see the section on Renewable Diesel beginning on page 36)*

• What is a reasonable estimate of when **Fisher-Tropsch diesel** will be fully commercialized and available in OR? What are likely volumes of Fisher-Tropsch diesel that can be made available, given feedstocks in Oregon and the Pacific Northwest? Are there any other synthetic fuel production processes that we should consider? Please consider low, medium, and high estimates that will be feasible from now through 2022. *(For DEQ’s preliminary low and high estimates of Fisher-Tropsch diesel availability, please see the section beginning on page 40)*

**Electricity questions:**

• How many **electric vehicles** (full-battery) are likely to be on the road in 2022? What penetration rate is feasible in Oregon? Please consider low, medium, and high estimates that will be feasible from now through 2022. *(For DEQ’s preliminary low and high estimates of electric vehicle use, please see the section on Electricity beginning on page 45)*

• How many **plug-in hybrid electric vehicles** (vehicles that run on either gasoline or electricity) are likely to be on the road in 2022? What penetration rate is feasible in Oregon? Please consider low, medium, and high estimates that will be feasible from now through 2022. *(For DEQ’s preliminary low and high estimates of plug in hybrid electric vehicle use, please the section on Electricity beginning on page 45)*

**Compressed Natural Gas questions:**

• What volume of **compressed natural gas** will be used in the future, given the current status of fueling infrastructure and trends in use? Please consider low, medium, and high estimates that will be feasible from now through 2022 for both heavy-duty and light-duty applications. *(For DEQ’s preliminary low and high estimates of CNG use, please see the section on CNG beginning on page 52)*

• What are the prospects for residential and public CNG refueling?

**Other fuels questions:**

• Will **biogas, hydrogen**, or **liquefied natural gas (LNG)** be used in significant volumes in the future?

• What about **butanol or biobutanol**?

• Are there any other alternative fuels we should consider in large volumes for the compliance scenarios? For example, fuels made from algae.
**Fuels Covered**

There are many types of fuels that could be used to comply with an Oregon low carbon fuel standard. This document provides background on some of the various fuels which could potentially be supplied to Oregon so that the advisory committee can have adequate background to give input. DEQ would like to acknowledge Oregon Department of Energy’s substantial contribution toward writing many of these fuel assessments. This fuels assessment covers the following fuels and feedstocks:

**Ethanol**
1. Starch- and Sugar-Based Ethanol
2. Cellulosic Ethanol

**Diesel**
3. Biodiesel (FAME)
4. Renewable Diesel (Hydrogenation-Derived)
5. Fisher-Tropsch and Other Synthetic Fuels (such as synthetic diesel, cellulosic diesel, or synthetic gasoline)

**Electricity**
6. Electricity

**Natural Gas**
7. Biogas
8. Compressed Natural Gas (CNG)
9. Liquefied Natural Gas (LNG)

**Other**
10. Biobutanol/Butanol
11. Hydrogen
12. Algae

**Contents of Each Fuel’s Assessment**

- **Feedstock and Production Process.** For each of these fuels listed above, we give a brief description of the feedstock which can be used to make the fuel, and of the production process or processes. We also list additional materials produced during the manufacturing of a fuel. These “co-products” can displace the need for other materials to be manufactured and thereby have a significant effect on a fuel’s carbon intensity.

- **Commercialization Status of Fuel and Vehicles.** Next, we describe the commercialization status of the fuel. This includes information on whether the fuel is still in the early development stages and essentially has only been produced in a laboratory, whether it is in the initial stages of commercialization (for example, it has been produced at a pilot or demonstration scale), or whether it is fully commercialized.
and developed to the point at which it’s production and sale becomes economically feasible.

- **Production.** For each fuel, we also discuss statistics on production. We look at the current production or capacity for production in Oregon, whether there is potential for more production in Oregon based on the feedstock available, and then discuss production volumes or capacity in the rest of the United States or the world, if applicable.

- **Use of Fuel for Transportation Purposes.** Next, the fuel assessments contain (if information is available) a discussion of the current use of the fuel in Oregon, focusing on the volume used, the number of vehicles using the fuel, the existing infrastructure for the fuel, and any barriers to expansion or special issues.

- **Summary of Known Trends.** This section covers available data on trends in the use of the fuel for transportation, the production of the fuel (if relevant), and the use, availability or production of alternative-fueled vehicles. Where available, information is provided that is specific to trends in Oregon or the United States. For some fuels, data was not collected until recently. For example, the U.S. Energy Information Administration did not start collecting data on CNG used as a transportation fuel until 2004. For most fuel, information is not yet available for 2008 or 2009, although there are some exceptions.

- **Preliminary Estimates of 2022 Use.** This section contains estimates of future use, based on the trends in Oregon, the United States, or the world. Based on historic trends in fuel or vehicle use, regulatory requirements, studies, adoption rates in other areas, expert opinions, and methodologies used by others, DEQ has proposed a draft, preliminary estimate for low, moderate and high use in 2022 for some of the alternative fuels. The purpose is to solicit advisory committee input, data, discussion and feedback. DEQ intends to revise the estimates of alternative fuel and vehicle use after input and data have been obtained from the low carbon fuel advisory committee.

- **References and Further Reading.** Lastly, each fuel assessment contains references to the data, studies or reports from which the fuel assessment is developed. There are references and links for further reading at the end of each fuel assessment, should you want more information. If you are reviewing an electronic copy of this document and you are online, you can click on any reference to be taken to the original source.

**Summary of Fuels Assessment Discussion Paper**

Several of the fuels we assessed are not likely to be commercialized prior to 2022. California categorized these as “Long-Term – Technologies Projected after 2020.” The fuels assessment contains brief descriptions of these. Some fuels, such as hydrogen, are not likely to be used in

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Oregon in significant volumes due to infrastructure issues. Based on information available to date, DEQ does not anticipate using the following fuels in our compliance scenarios for Oregon:

- Liquefied Natural Gas
- Hydrogen
- Biofuels from algae

If you have information that indicates that a fuel listed above (or other fuels not included in this fuels assessment) will be used in Oregon or commercialized and produced in substantial volumes by the year 2022, please share that information with Sue Langston, and include the name of the fuel and production process, a short description of the production process, the number and location of pilot/demonstration/commercial plants, and any information helpful to evaluating the potential for use in 2020.

The following three tables summarize the information found in the assessments for each fuel, such as commercialization status, production, and use of the fuels which are likely to be commercially produced and available within the low carbon fuel standard timeline. For more details, please refer to each fuel assessment.

**Table 1** summarizes commercialization status and production information for alternative fuels.

**Table 2** summarizes proposed low, moderate and high estimates of alternative fuels use in 2022. These are for discussion purposes only. DEQ intends to revise these after input from the low carbon fuel advisory committee.

**Table 3** summarizes proposed low, moderate and high estimates of alternative fueled vehicles in 2022. These are for discussion purposes only. DEQ intends to revise these after input from the low carbon fuel advisory committee.
Table 1: Summary Table for Alternative Fuels. Details and references for each fuel and information cited are found in the fuel assessments. For fuel used only in alternative-fueled vehicles (flex fuel vehicles which use E85, electricity, CNG, LNG and hydrogen) please see “Table 3: Summary Table for Alternative Fueled Vehicles in Oregon in 2022” on page 9.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Commercialization of fuel</th>
<th>Production of Fuel</th>
<th>Planned Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Commercial Plants in US</td>
<td>Number of Pilot or Demonstration Plants in US</td>
<td>Oregon Production Capacity (Million gal per year)</td>
</tr>
<tr>
<td>Starch- and Sugar-Based Ethanol</td>
<td>189 (2 in Oregon)</td>
<td>Unknown</td>
<td>Not Applicable.</td>
</tr>
<tr>
<td>Cellulosic Ethanol</td>
<td>0 currently</td>
<td>0 currently</td>
<td>26 pilot, demo, or commercial plants under construction</td>
</tr>
<tr>
<td>Biodiesel (FAME)</td>
<td>173 (6 in Oregon)</td>
<td>Unknown</td>
<td>Not Applicable.</td>
</tr>
<tr>
<td>Renewable Diesel (Hydrogenation-Derived)</td>
<td>0 currently</td>
<td>0 currently</td>
<td>2 under construction 2 planned (in 2009)</td>
</tr>
<tr>
<td>Fisher-Tropsch</td>
<td>0 currently</td>
<td>4</td>
<td>At least 2</td>
</tr>
<tr>
<td>Biogas</td>
<td>Unknown</td>
<td>Unknown</td>
<td>Unknown</td>
</tr>
<tr>
<td>Biobutanol</td>
<td>0 currently</td>
<td>0 currently</td>
<td>At least 4</td>
</tr>
<tr>
<td>Algae</td>
<td>0 currently</td>
<td>0 currently</td>
<td>Unknown</td>
</tr>
</tbody>
</table>

* Some demonstration and pilot projects are currently producing and selling fuel.

** Only some of this is used for transportation purposes
### Table 2: Summary table for projected alternative fuel use in Oregon in 2022.

Details and references for each fuel and information cited are found in the fuel assessments.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Trends</th>
<th>Low estimate of 2022 use and rationale</th>
<th>Moderate estimate of 2022 use and rationale</th>
<th>High estimate of 2022 use and rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Starch- and Sugar-Based Ethanol (waste)</td>
<td>Production fully commercialized.</td>
<td><strong>1.5 million gallons</strong> Based on current OR capacity.</td>
<td>There is potential for a pilot/demonstration scale plant.</td>
<td>There is potential for a commercial plant to be built, depending on feedstocks.</td>
</tr>
<tr>
<td>Starch- and Sugar-Based Ethanol (crops)</td>
<td>Production fully commercialized.</td>
<td><strong>40 million gallons</strong> Based on current OR plants in operation.</td>
<td><strong>40 million gallons</strong> Based on current OR plants in operation.</td>
<td><strong>145.5 million gallons</strong> Based on current existing OR plants</td>
</tr>
<tr>
<td>Cellulosic Ethanol (consider waste vs. crops)</td>
<td>Commercial facilities are under construction. Production not commercialized. Many pilot/ demonstration projects.</td>
<td><strong>58 million gallons</strong> Based on RFS2 EPA estimates. (Primary Control Case)</td>
<td><strong>189 million gallons</strong> Based on RFS2 EPA estimates. (High Ethanol Control Case)</td>
<td><strong>244 million gallons</strong> Based on EPA Table 1.8-14: Projected Cellulosic Ethanol Volumes by State. Urban waste: 44 million. Forest: 200 million gallons.</td>
</tr>
<tr>
<td>Biodiesel (FAME) (consider waste vs. crops)</td>
<td>Production fully commercialized.</td>
<td>Based on OR’s future 5% renewable fuel standard, <strong>26.5 million gallons</strong></td>
<td>Moderate and high estimates of biodiesel availability in Oregon could be based on trends in biodiesel production, volume or feedstocks available regionally, federal RFS2 required volumes, or future predictions of use.</td>
<td></td>
</tr>
<tr>
<td>Renewable Diesel (Hydrogenation-Derived)</td>
<td>Production fully commercialized.</td>
<td><strong>Zero</strong> It is possible no renewable diesel will be available in Oregon.</td>
<td><strong>25 – 100 million gallons</strong> Based on proposed project and potential for project to supply some fuel to Oregon.</td>
<td><strong>100-500 million gallons</strong> Based potential for commercial production by a WA refiner.</td>
</tr>
<tr>
<td>Fisher-Tropsch from coal or gas</td>
<td>Production fully commercialized.</td>
<td><strong>Zero</strong> Based on little incentive from RFS2 or LCFS.</td>
<td><strong>Zero</strong> Based on little incentive from RFS2 or LCFS.</td>
<td><strong>Zero</strong> Based on little incentive from RFS2 or LCFS.</td>
</tr>
<tr>
<td>Fisher-Tropsch or other synthetic diesel from biomass or waste</td>
<td>Production process under development.</td>
<td><strong>77 million gallons</strong> Based on RFS2 EPA estimates (Primary Control Case).</td>
<td><strong>110 million gallons</strong> Based on RFS2 EPA. (Low Ethanol Case)</td>
<td><strong>150-300 million gallons</strong> Based on commercialization status, commercial scale facilities could be built.</td>
</tr>
<tr>
<td>Biogas</td>
<td>Production fully commercialized.</td>
<td><strong>Zero</strong> Based on historic and current use.</td>
<td>1/2 of remaining unused biogas potential in Oregon.</td>
<td>3/4 of remaining unused biogas potential in Oregon.</td>
</tr>
<tr>
<td>Biobutanol or butanol</td>
<td>Production not commercialized. No commercial facilities under construction.</td>
<td><strong>Zero</strong> Based on commercialization status.</td>
<td><strong>10 to 25 million gallons</strong> Based on the proposed biobutanol plant in Oregon.</td>
<td><strong>25 to 75 million gallons</strong> There is potential for commercial production to be built and producing by 2022.</td>
</tr>
<tr>
<td>Algae</td>
<td>Production not commercialized. Few pilot projects, many issues.</td>
<td><strong>Zero</strong> Based on commercialization status.</td>
<td><strong>Zero</strong> Based on commercialization status.</td>
<td><strong>Zero</strong> Based on commercialization status.</td>
</tr>
</tbody>
</table>

**Table Sources:**
Table 3: Summary Table for Alternative Fueled Vehicles in Oregon in 2022. Details for each fuel and information cited are found in the fuel assessments. The low, moderate, and high estimates are for discussion purposes only. DEQ intends to revise these based on low carbon fuel advisory committee input or any additional data provided.

<table>
<thead>
<tr>
<th>Vehicles</th>
<th>Low estimate – 2022</th>
<th>Moderate estimate - 2022</th>
<th>High estimate – 2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flex fuel vehicles (use gasoline with blends up to 85% ethanol)</td>
<td>Estimates for number of flex fuel vehicles, E85 consumption, and access to E85 fueling stations could be based on:</td>
<td></td>
<td>The rate of change in other areas with high ethanol use, on future predictions, or on the “Low Ethanol Control Case” from RFS2.3</td>
</tr>
<tr>
<td>Oregon stats:</td>
<td>Historic use, EIA predictions, the rate of change in other areas with high ethanol use, on future predictions, or on the “Low Ethanol Control Case” from RFS2.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• 9 public fueling stations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• 100,000 flex fuel vehicles (2009)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercialization status:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric vehicles</td>
<td>Based on Oregon’s Low Emission Vehicle rules, a minimum of approximately 12,000 full battery electric vehicles and 17,000 plug-in hybrid electric vehicles must be placed in Oregon in by 2022. 4</td>
<td>Moderate and high estimates could be based on future electric vehicle predictions from consultants, government or auto manufacturers.</td>
<td></td>
</tr>
<tr>
<td>Oregon stats:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Aprox. 30 public fueling stations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• 1636 vehicles (2007)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercialization status:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Light-duty (passenger): Electric vehicles are on the verge of wide commercialization. 9 full-function electric vehicles or plug-in hybrid electric vehicles are due to be launched by 2011 (in addition to low-speed and neighborhood vehicles).</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Medium/heavy-duty: Four heavy-duty plug-in vehicles are currently available with two more coming to market in 2010. For some applications, such as forklifts, there are many models available.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Vehicles</th>
<th>Low estimate – 2022</th>
<th>Moderate estimate - 2022</th>
<th>High estimate – 2022</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Compressed Natural Gas (CNG)</strong></td>
<td>A low estimate could be based on the historic rate of increase for CNG use in Oregon or the US, or on future predictions. Most of the increase would likely be in the medium-duty vehicle range.</td>
<td>Moderate and high estimates could be based on several different sources of information, such as future electric vehicle predictions from consultants, natural gas associations, government or natural gas vehicle manufacturers.</td>
<td></td>
</tr>
<tr>
<td>Oregon stats:</td>
<td>• 2 public fueling stations</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 9-10 other fueling stations</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 1500 vehicles (2007)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Medium/ heavy-duty: commercialized and available for applications such as buses, step vans and trucks.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Liquefied Natural Gas (LNG)</strong></td>
<td>Zero Based on the historic use and lack of fueling infrastructure, DEQ proposes not to include any LNG in the compliance scenarios for the low carbon fuel standard.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oregon stats:</td>
<td>• No vehicles</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• No fueling stations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercialization status:</td>
<td>Light-duty: not commercialized</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Medium/ heavy-duty: commercialized and available for applications such as refuse haulers, local delivery, and transit buses.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrogen</strong></td>
<td>Zero Based on the historic use, commercialization status, and lack of fueling infrastructure, DEQ proposes not to include any LNG in the compliance scenarios for the low carbon fuel standard.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oregon stats:</td>
<td>• No vehicles</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• No fueling stations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercialization status:</td>
<td>Not commercialized</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Starch- and Sugar-Based Ethanol

Feedstock and production process

Feedstock. According to the US Department of Energy: “The vast majority of today's ethanol is derived from starch- and sugar-based feedstocks. The sugars in these feedstocks are relatively easy to extract and ferment using widely available biochemical conversion technologies, making large-scale ethanol production affordable. Starch-based feedstocks include plants such as corn, wheat, and milo. The starches in these plants are chains of sugars that can be broken down into simple sugars before fermentation. Sugar-based feedstocks, such as sugar cane, sorghum and sugar beets, contain simple sugars that can be extracted and fermented readily. Corn is used for more than 90 percent of current U.S. ethanol production. Brazil, the world's second-largest ethanol producer behind the United States, uses sugar cane as a feedstock.⁵

Starch- and sugar-based ethanol can also be made from waste starch and sugar products such as food processor and agricultural wastes or food store spoilage.

Production process. Corn ethanol is produced using either a dry-mill or wet-mill process. The difference between the two processes is the initial treatment of the biomass. Wet-mill facilities were common in the industry's early days, but now dry-mill facilities account for more than 80 percent of industry capacity. Dry-mill plants are typically smaller than wet-mill plants and use less energy per gallon of ethanol produced.⁶

- **Corn ethanol by dry-mill process:** First the corn is ground into a powdered meal, which is then mixed with water and enzymes to convert the starch into fermentable sugars. Yeast is added to ferment the sugars into ethanol. After distillation to separate the alcohol from the remaining water and solids, a denaturant such as gasoline is added to make the alcohol unfit for human consumption.

- **Corn ethanol by wet-mill process:** The corn grain is first soaked in hot water to separate the protein and starch. The product is then coarsely ground, and the germ is separated to be processed into corn oil. Next, the remaining slurry, which contains gluten, starch, and fiber, is finely ground and separated so the fiber can be blended into animal feed and the starch/gluten mixture can be further processed. The starch is then dried to make corn starch or

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⁵ US Department of Energy (US DOE) website. [http://www.afdc.energy.gov/afdc/ethanol/feedstocks_starch_sugar.html](http://www.afdc.energy.gov/afdc/ethanol/feedstocks_starch_sugar.html)

⁶ US DOE website. [http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html](http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html)
processed to produce sugars, corn syrup, and beverage sweeteners. The sugars are then fermented to produce ethanol.  

- **Ethanol from waste starches and sugars:** Waste products from food processors may arrive at the plant in mainly solid form (for example, fruit “seconds” that are unsuitable for sale), or may already contain a substantial amount of water (for example, wastewater from processing potatoes). If needed, the solids are ground, and then in the case of starchy wastes, enzymes are added to convert the starch into fermentable sugars. Appropriate strains of yeast are added to ferment the sugars into ethanol, and the ethanol is separated by distillation and a denaturant is added to prevent human consumption.

<table>
<thead>
<tr>
<th>Co-products</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dry-mill process:</strong></td>
<td>The two main co-products associated with the dry-mill production of ethanol are distillers grain and carbon dioxide. Distillers grain (wet or dry solids and liquids remaining after distillation), is generally recombined for sale as high-protein animal feed. Some facilities also incorporate dryers to remove the moisture from the wet distillers grains and to extend its shelf life. This dried co-product is called dried distillers grain with solubles. The CO(_2) co-product is commonly captured and marketed to the food processing industry for use in carbonated beverages or the production of dry ice.</td>
</tr>
<tr>
<td><strong>Wet-mill process:</strong></td>
<td>The main products of the wet-mill process are corn sweeteners such as high fructose corn syrup; however they also produce corn ethanol, corn oil, animal feed, and cornstarch.</td>
</tr>
<tr>
<td><strong>Waste starches and sugars:</strong></td>
<td>There is potential for co-products from this production process, however not much work has been done in this area.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Commercialization status</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fuel</strong></td>
<td>The production of ethanol from starch and sugar crops (such as corn and sugarcane) is fully commercialized. Production of ethanol from waste starches and sugars is in an early stage of commercialization, with some wastes (such as potato processing wastewater and waste berries) already converted into ethanol on a small commercial scale. More work is needed to perfect production processes for other waste starches and sugars.</td>
</tr>
<tr>
<td><strong>Vehicles</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Gasoline vehicles.</strong></td>
<td>Existing gasoline vehicles can use a blend containing</td>
</tr>
</tbody>
</table>

---

8 US DOE, Alt Fuels & Advanced Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html](http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html)
9 US DOE, Alt Fuels & Advanced Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html](http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html)
up to 10 percent ethanol. They are fully commercialized.

**Flex fuel vehicles.** Flex fuel vehicles can be filled with either gasoline or a gasoline blend of 85 percent ethanol (E85). Flex fuel vehicles can use blends from all gasoline to an 85 percent ethanol/15 percent gasoline blend. Flex fuel vehicles are becoming increasingly available, and GM and Ford have said that by 2012, half of the vehicles they offer for sale will be flex fuel vehicles.¹⁰

<table>
<thead>
<tr>
<th>Current production in Oregon</th>
<th>Oregon ethanol production capacity is presently at 149.5 million gallons per year, however only 41.5 million gallons per year are operational.</th>
</tr>
</thead>
</table>
| **Cascade Grain Products, LLC** | Plant location: Clatskanie, Oregon  
Status: Currently not operational, Auction scheduled for December 2009 under Chapter 7  
Capacity: 108 million Gal/yr  
Process: Dry-mill, natural gas, DDGS  
Feedstock: Corn |
| **Pacific Ethanol, Inc** | Plant location: Boardman, Oregon  
Status: Operational  
Capacity: 40 million Gal/yr  
Process: Dry-mill, natural gas, WDGS  
Feedstock: Corn |
| **Summit Natural Energy** | Plant location: Cornelius, Oregon  
Status: Operational  
Capacity: 1.5 million Gal/yr  
Process: Biochemical  
Feedstock: Agricultural waste |

| Potential production in Oregon | Oregon has very limited ability to grow corn. However, given Oregon’s location along rail transport lines from the Midwest to Pacific ports, Oregon could potentially produce large quantities of ethanol using Midwestern corn.  
Oregon does have additional ability to produce ethanol from waste starches and sugars, particularly from food processing. However, knowledge of the amount of potentially available feedstock is sparse, and there are two categories of difficulties to overcome: intermittent availability of potential feedstocks, tied to seasonal harvests; and finding suitable yeasts and |

¹⁰ For links to the GM and Ford commitments for flex fuel vehicles, please visit: [http://www.afdc.energy.gov/afdc/vehicles/flexible_fuelavailability.html](http://www.afdc.energy.gov/afdc/vehicles/flexible_fuelavailability.html)
enzymes for each specific feedstock to optimize fermentation. See the Oregon Biomass Assessment report prepared for the April 15, 2010 Advisory Committee meeting for information on Oregon’s potential for producing biomass. (http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm)

### Out-of-state production

In Idaho, 65 million gallons per year is currently operational.

**Pacific Ethanol, Inc**
- Plant location: Burly, Idaho
- Status: Operational (restarted production in December 2009 after coming out of Chapter 11)
- Capacity: 60 million Gal/yr
- Process: Dry-mill, natural gas, WDGS
- Feedstock: Corn

**Idaho Ethanol Processing, LLC**
- Plant location: Caldwell, Idaho
- Status: Operational
- Capacity: 5 million Gal/yr
- Process: Biochemical, natural gas
- Feedstock: Food processing and agricultural waste

According to the Renewable Fuels Association (RFA)\(^{11}\) as of October 2009 the U.S. has an ethanol production capacity of 13,131.4 million gallons per year of which 11,930.4 million gallons per year is operational. Another 1,432 million gallons per year capacity is under construction or expansion. The world in 2008 produced approximately 17,335 million gallons of ethanol.\(^{12}\)

Several small facilities produce ethanol from waste sugars and starches such as potato processing waste and brewery waste.\(^{13}\)

### Current use in Oregon

- **Volume.** Over 150 million gallons of ethanol is used annually in Oregon.\(^ {14}\) A 10 percent ethanol blend is required by the Oregon renewable fuel standard, with some exceptions.\(^ {15}\)
- **Number of vehicles.** Any gasoline vehicle can use up to 10 percent

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\(^{11}\) Renewable Fuels Association website. [http://www.ethanolrfa.org/industry/statistics/](http://www.ethanolrfa.org/industry/statistics/)

\(^{12}\) Renewable Fuels Association website. [http://www.ethanolrfa.org/industry/statistics/#E](http://www.ethanolrfa.org/industry/statistics/#E)


\(^{14}\) Rick Wallace, ODOE, personal communication

ethanol. Flex fuel vehicles can use up to 85 percent ethanol (E85). There are over 100,000 flex fuel vehicles in Oregon. In the US in 2007, E85 accounted for an estimated 54 million gallons of gasoline equivalent.

**Existing fueling infrastructure.** Over 99 percent of the gasoline dispensers in Oregon dispense a 10 percent ethanol blend. At present there are nine stations that offer E85.

**Barriers to expansion.** The main barriers to expanded use of ethanol in Oregon are the small market share of flex fuel vehicles and the small number of E85 fueling stations.

The use of ethanol in blends above E10 has been seriously restricted by the failure of pumps handling higher concentrations to gain Underwriter’s Laboratory approval (a product safety certification company). Recently, Underwriter’s Laboratory approved a pump for up to 25% blends of ethanol. It is possible that this barrier to the use of E85 will be overcome in the future, allowing E85 to be more widely available.

**Special issues.** Ethanol produced from waste starches and sugars qualifies as an “advanced biofuel” under the federal RFS2, potentially giving producers a commercial boost.

<table>
<thead>
<tr>
<th>Summary of known trends:</th>
<th>Trends in Ethanol</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Volume produced</strong></td>
<td><strong>Volume produced</strong></td>
</tr>
<tr>
<td><strong>Volume used</strong></td>
<td><strong>Trend #1:</strong> Ethanol produced from starch and sugars is an example of how quickly a new fuel can go from very low production to large production volumes. Ethanol production in the United States has increased from 954 million gallons of gasoline equivalent in 1998 to 6,230 million gallons of gasoline equivalent in 2008.</td>
</tr>
<tr>
<td><strong>Number of vehicles</strong></td>
<td><strong>Trend #2:</strong> The same decade has seen three ethanol plants open (and one close) in Oregon.</td>
</tr>
</tbody>
</table>

**Volume used**
It is unknown how much E85 is used in Oregon.

**Number of flex fuel vehicles.** (Flex fuel vehicles are cars or trucks)

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16 Rick Wallace, Oregon Department of Energy (ODOE), personal communication 2/2010
capable of using gasoline or ethanol blends up to 85%)

**Trend #3:** In the U.S., consumption of ethanol in flex fuel vehicles has increased approximately 23% per year from 2000 to 2007 (from 1.2 million gallons of gasoline equivalent to over 54 million gallons of gasoline equivalent).\(^{22}\)

**Trend #4:** Options for light-duty passenger E85 vehicles increased exponentially during the last decade. In 2008, 31 new types of flex fuel vehicles were offered for sale.\(^{23}\)

**Trend #5:** Use of medium- and heavy-duty E85 flex fuel vehicles was negligible until 2006, when EIA reported 117,003 medium-duty flex fuel vehicles.\(^{24}\)

**Trend #6:** The Environmental Protection Agency has received a petition to increase the ethanol blendwall to 15%. The US Department of Energy has been conducting testing related to this issue, and is scheduled to complete a study that will provide critical data in June 2010.\(^{25}\)

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
<th>Future estimates of flex fuel vehicles and E85 use</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Future use</strong></td>
<td><strong>Ethanol used in flex fuel vehicles (E85)</strong></td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td><strong>Forecast #1:</strong> Several auto manufacturers have said that by 2012, half of the vehicles they offer for sale will be flex fuel vehicles.(^{26}) New cars are increasingly being designed to run on E85, which could increase the fuel efficiency of flex fuel vehicles. The Energy Information Administration predicts that the fuel economy of flex fuel vehicles will improve dramatically in the next five years, so that by 2015, many flex fuel vehicles will achieve virtually the same MPG as similar gasoline vehicles.(^{27})</td>
</tr>
<tr>
<td><strong>Moderate</strong></td>
<td><strong>Volume of E85 used in flex fuel vehicles</strong></td>
</tr>
<tr>
<td><strong>High</strong></td>
<td><strong>Forecast #2:</strong> The Energy Information Administration predicts an increase in E85 use compared to historic trends, all of it in light-duty cars and</td>
</tr>
</tbody>
</table>

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\(^{22}\) US DOE, Alt Fuels & Advanced Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/data/fuels.html](http://www.afdc.energy.gov/afdc/data/fuels.html)


\(^{26}\) For links to the GM and Ford commitments for flex fuel vehicles, please visit: [http://www.afdc.energy.gov/afdc/vehicles/flexible_fuel_availability.html](http://www.afdc.energy.gov/afdc/vehicles/flexible_fuel_availability.html)

trucks. The EIA estimates that E85 use will increase beginning in 2016; and that by 2022, use of E85 will reach 625.2 trillion btu nationwide.\(^{28}\)

**Number of flex fuel vehicles**

**Forecast #3:** The volumes of biofuels required by the federal Renewable Fuel Standard 2 are likely to necessitate increased E85 infrastructure and E85 use.\(^{29}\) EPA calculated the costs associated with needed infrastructure, and also predicted that sales of light-duty flex fuel vehicles could range from 2.6 to 13.7 million nationwide\(^{30}\), while EIA only predicted sales of 1.5 million.\(^{31}\)

**Forecast #4:** A low carbon fuel standard in Oregon could potentially spur more E85 use in flex fuel vehicles than would have happened otherwise. Trends in other countries or states that use large volumes of flex fuel vehicles could help us identify feasible adoption rates for both light-duty/passenger and medium/heavy-duty applications.

**Ethanol blendwall**

**Forecast #5:** The current blendwall (the maximum amount of ethanol that can be blended into conventional gasoline) for ethanol in conventional gasoline engines is 10%. Washington State is considering using a 15% ethanol blendwall based on the federal Renewable Fuel Standard 2 in developing their low carbon fuel standard compliance scenarios.\(^{32}\)

**Forecast #6:** The volumes of biofuels required by the federal Renewable Fuel Standard 2 might necessitate more than 10% ethanol blended into gasoline.\(^{33}\)

**Low estimate (proposed for discussion)**

A low estimate for number of flex fuel vehicles, E85 consumption, and access to E85 fueling stations could be based on historic use, Energy Information Administration predictions, or on the “Low Ethanol Control Case” from the federal Renewable Fuel Standard 2.\(^{34}\)


### Moderate estimate (proposed for discussion)

A moderate estimate for number of flex fuel vehicles, E85 consumption, and access to E85 fueling stations could be based on Energy Information Administration predictions, on the rate of change in other states or countries that have focused on using biofuels, on consultant reports, or on the “Primary Control Case” from the federal Renewable Fuel Standard 2.  

### High (but feasible) estimate

A high (but feasible) estimate for number of flex fuel vehicles, E85 consumption, and access to E85 fueling stations could be based on Energy Information Administration predictions, on the rate of change in other states or countries that have focused on using biofuels, on consultant reports, or on the “High Ethanol Control Case” from the federal Renewable Fuel Standard 2.

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**Further reading:**

  [http://www.epa.gov/otaq/renewablefuels/420f09065.htm](http://www.epa.gov/otaq/renewablefuels/420f09065.htm)

- **U.S. Department of Energy. Conversion of gasoline to flex fuel.**  
  [http://www.afdc.energy.gov/afdc/technology_bulletin_0807.html](http://www.afdc.energy.gov/afdc/technology_bulletin_0807.html)

- **U.S. Department of Energy. Data, Analysis, and Trends.**  

  [http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm](http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm)

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[http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm](http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm)

[http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm](http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm)
Figure 1: Processes for Producing Sugar- and Starch-Based Ethanol

Dry Mill Ethanol Process

Source: Renewable Fuels Association

US DOE. Alt Fuels & Adv Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html]
## Cellulosic Ethanol

| Feedstock and production process | Feedstock. | Cellulose is the main component of plant cell walls and is the most common organic compound on earth. Cellulosic ethanol is chemically identical to starch-based ethanol but instead derived from "biomass," a term encompassing everything from waste materials like corn stover and cobs, mill waste and paper pulp, to fast-growing plants like switchgrass and poplar.  

Cellulose is a polymer of glucose, a simple sugar that is easily consumed by yeast to produce ethanol. Polymers are large molecules made up of simpler molecules bound together much like links in a chain. Plants use cellulose as a strengthening material, much like a skeleton, which allows them to stand upright and grow toward the sun, withstand environmental stresses, and block pests. Because of this strengthening, it is difficult to break cellulose down into its simple sugar components, requiring additional processing compared to starch-based ethanol.  

**Production process.** There are many processes at various stages of research and development for producing cellulosic ethanol. The two main categories of processes are biochemical conversion and thermochemical conversion. Companies use either one or the other of these processes, or some combination of the two. Figure 1 at the end of this fuel assessment contains diagrams for each category. For more information, consult the U.S. Department of Energy Biomass Program website at: [http://www1.eere.energy.gov/biomass/abcs_biofuels.html#prod](http://www1.eere.energy.gov/biomass/abcs_biofuels.html#prod).

- **Biochemical Conversion:** Because cellulosic feedstocks are more difficult to break down into fermentable sugars than starch- and sugar-based feedstocks, the cellulosic biochemical conversion process requires additional steps (see diagram in Figure 1). Two key steps are biomass pretreatment and cellulose hydrolysis. During pretreatment, the hemicellulose part of the biomass is broken down into simple sugars and removed for fermentation. During cellulose hydrolysis, the cellulosic portion of the biomass is broken down into the simple sugar glucose.

- **Thermochemical Conversion:** Ethanol can also be produced using thermochemical processes. In this approach, heat and chemicals are used to break biomass into syngas (a mixture of carbon monoxide... |

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and hydrogen) and reassemble it into products such as ethanol.

**Co-products**

In many instances, the biomass to produce cellulosic ethanol is itself a co- or by-product of agricultural or industrial processes. Several of the technologies that are currently under development produce interesting co- or by-products, which can significantly improve the economics of biorefineries.  

- Lignin is a non-fermentable residue that is the natural binding component in plants, which can be employed to power the operation. Eventually, lignin may be used in commercial applications such as plastics.
- Ash left over from burning lignin can be used as a soil amendment.
- Protein from the leaves and stems of the feedstock plants can be used in animal feed. Agricultural residues contain four to six percent protein while crops like switchgrass and alfalfa contain 10 percent and 15 to 20 percent, respectively.

**Commercialization status**

**Fuel.** Cellulosic ethanol has not yet been produced commercially. However, several commercial cellulosic ethanol production plants are under construction, and intensive research and development is rapidly advancing the state of cellulosic ethanol technology. Several pilot and demonstration plants are now operating.

**Vehicles.** Gasoline vehicles which can use a blend containing 10 percent ethanol are fully commercialized, as are flex fuel vehicles which use gasoline, 85% ethanol, or a mix of the two. (See Starch- and Sugar-Based Ethanol section on page 17 for details on flex fuel vehicle use)

**Current production in Oregon**

No cellulosic ethanol plants are currently operational in Oregon. However, several companies are in various stages of planning and construction for demonstration and pilot facilities.

**ZeaChem**

Plant location: Boardman, Oregon  
Status: Construction has begun on a 250,000 Gal/yr pilot plant, completion planned end of 2011  
Product: Acetic acid, which can be converted to ethanol  
Process: Biochemical and thermochemical  
Feedstock: Woody biomass (poplar)

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Future plans: Construction of a 25 to 50 million Gal/yr commercial plant to begin in 2010, estimated completion 2013
Awarded $25 million grant from U.S. DOE

**Pacific Ethanol**
Plant Location: Boardman, Oregon
Status: Planned 2.7 million Gal/yr cellulosic ethanol plant in addition to existing corn ethanol plant, completion date unspecified
Process: Biochemical
Feedstocks: Woody biomass (poplar) and wheat straw
Awarded $24 million grant from U.S. DOE

**Diesel Brewing**
Plant location: Salem, Oregon
Status: Demonstration facility (Phase I start-up date: December 2009)
Product: Cellulosic bio-butanol and ethanol
Process: Gasification, synthesis gas cleanup and catalytic conversion
Feedstocks: Dairy manure and woody biomass
Future plans: Semi-commercial plant, Eastern Oregon

**Trillium Fiber Fuels**
Facility location: Corvallis Oregon
Status: R&D, developing isomerization process-small batch
Process: Biochemical
Feedstocks: Grass and wheat straw and softwoods
Awarded $750,000 from U.S. DOE to develop cellulosic technology

| Potential production in Oregon | Oregon is rich in biomass potential. Feedstocks from forest residues, mill residues, agricultural residues, urban wood wastes and dedicated energy crops are all areas of potential for cellulosic ethanol production. See Biomass Assessment for more details. See the Oregon Biomass Assessment report prepared for the April 15, 2010 Advisory Committee meeting for information on Oregon’s potential for producing biomass for cellulosic biofuels. [http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm](http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm) |

| Diesel Brewing | Plant location: Boardman, Oregon
Status: Demonstration unit (Phase II), 10-ton/day. Start-up date planned for October 2010.
Product: Cellulosic bio-butanol and ethanol
Process: Gasification, synthesis gas cleanup and catalytic conversion
Feedstocks: Dairy manure and woody biomass
Future plans: Commercial Scale, at least 100 dry tons/day, Boardman, Oregon (October 2012) |
Out-of-state production

The U.S. Department of Agriculture and the U.S. Department of Energy have found that at least 1 billion tons of cellulose could be sustainably collected and processed in the U.S. each year. This resource represents an equivalent of 67 billion gallons of ethanol, replacing 30 percent of gasoline consumption in the United States.45

Currently there are no large-scale commercial cellulosic ethanol plants operating in the United States; however, several pilot and semi-commercial plants are operating in the United States46 and around the world.47 POET Ethanol and AE Biofuels have plants using corn cobs and stover as feedstocks, while KL Energy Corporation and Range Fuels are using woody biomass. Coskata uses a process that can process several different feedstocks, ranging from agricultural waste to garbage. The ability to produce cellulosic ethanol using many feedstocks and several different technologies is proven, but these technologies need to be scaled up and commercialized and costs need to come down in order to be competitive in the transportation fuels market.

Some companies are reporting significant progress in reducing production costs. For example, over the first year of operations at its pilot scale ethanol plant in South Dakota, POET Ethanol reduced their production costs from $4.13 per gallon to $2.35, and intends to reduce costs to below $2.00 per gallon by the time their commercial plant comes on-line.48

Current use in Oregon

- Volume
- Number of vehicles
- Existing fueling infrastructure
- Barriers to

Volume. Over 150 million gallons of ethanol is used in Oregon. It is difficult to say how much of this is cellulosic because no one is tracking this information. Although cellulosic ethanol is not produced at a commercial scale, several plants produce and market cellulosic ethanol from pilot and demonstration-sized plants.49

Number of vehicles. Cellulosic ethanol is chemically indistinguishable from starch-based ethanol. Any gasoline vehicle can use blends up to 10 percent ethanol or E10. Flex fuel vehicles can use blends from E0 to E85 (85

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46 US DOE. Integrated Biorefinery Project Locations (for refineries producing ethanol, diesel, or other products from biomass that have received a grant award). Refineries are categorized as in the research and development, pilot, demonstration, or commercial stage.  http://www1.eere.energy.gov/biomass/integrated_biorefineries.html
49 Iogen website.  http://www.iogen.ca/
### Existing fueling infrastructure.
Over 99 percent of the gasoline dispensers in Oregon dispense a 10 percent ethanol blend. At present there are nine stations that offer E85.

### Barriers to expansion.
There are no barriers to using cellulosic ethanol once it is produced, as it is indistinguishable from starch-based ethanol already in use. The barriers lie in producing cellulosic ethanol at industrial scale at competitive prices, and obtaining financing.

### Special Issues.
The Environmental Protection Agency, under the Renewable Fuel Standard Program, will require that renewable fuel be blended into petroleum from 9 billion gallons in 2008 to 36 billion gallons by 2022. There are several different categories of required renewable fuel. In 2022, the following will be required in the United States:

- 16 billion gallons of cellulosic biofuels (which could be ethanol or diesel)
- 4 billion gallons of unspecified “advanced” fuel, which will need to have a carbon intensity of 50% less than petroleum fuels. These could be cellulosic ethanol, biomass-based diesel, or some other fuel.

The federal program is a volumetric program which means the fuel distributors could sell high blends in one region and zero or low blends in another region and still meet the programs requirement. The program is primarily designed to significantly increase the volume of renewable fuel that is blended into gasoline. EPA recognizes that the required volumes could be met with a wide variety of fuel choices, and has developed a projected set of reasonable fuel volumes based on their best estimate of likely fuels that would come to market. They have projected a primary control case, and then two sensitivity control cases (high and low cellulosic ethanol).

See the Appendix A on page 78 for more information on the federal Renewable Fuel Standard 2.

### Trends in Cellulosic Ethanol as a transportation fuel

#### Volume produced
1. Production in Oregon: One cellulosic ethanol demonstration plant is planned, while another will begin construction soon. There are plans for a

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**Summary of known trends:**
- Volume produced
- Volume used

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50 Rick Wallace, Oregon Department of Energy, personal communication 2/2010
51 EPA Proposes New Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond. [http://www.epa.gov/oms/renewablefuels/420f09023.htm#3](http://www.epa.gov/oms/renewablefuels/420f09023.htm#3)
- **Number of vehicles**
  
  commercial facility with a capacity of 25-50 million gallons per year.

2. Production in the US. There are approximately 26 pilot, demonstration, and planned commercial cellulose ethanol plants in the United States.⁵²

3. Due to the federal Renewable Fuel Standard 2, higher volumes of lower carbon biofuels will be required.

**Volume used and number of E85 vehicles.** For trends in ethanol and E85 (15% gasoline and 85% ethanol) use, please refer to the Ethanol from Starch- and Sugar-Based Ethanol section of this Fuels Assessment on page 17.

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
<th>Future use estimates for cellulosic ethanol</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Future use</td>
<td>A low carbon fuel standard in Oregon could potentially spur cellulosic ethanol production with lower carbon emissions than would have occurred under the federal Renewable Fuel Standard 2. In addition, some of the fuel that will be used to meet RFS2 will be exempt from the low carbon fuel standard, such as heating oil, propane, and jet fuel.</td>
</tr>
<tr>
<td>• Low</td>
<td></td>
</tr>
<tr>
<td>• Moderate</td>
<td></td>
</tr>
<tr>
<td>• High</td>
<td></td>
</tr>
</tbody>
</table>

**Low estimate (proposed for discussion)**

EPA’s Primary Control Case (for the Renewable Fuel Standard Program) predicts there will be an estimated 4.92 billion gallons of cellulosic ethanol in 2022. Based on Oregon’s consumption of gasoline and diesel compared to that of the entire United States, Oregon’s share of this is **58 million gallons**.⁵³

**Moderate (proposed for discussion)**

EPA’s High Ethanol Control Case predicts there will be an estimated 16 billion gallons of cellulosic ethanol in 2022. Based on Oregon’s consumption of gasoline and diesel compared to that of the entire United States, Oregon’s share of this is **189 million gallons**.⁵⁴

**High (but feasible) estimate (proposed for discussion)**

EPA conducted an analysis of available cellulosic feedstock in each state. Based on their analysis, 44 million gallons of cellulosic ethanol could be produced from urban waste and 200 million gallons from

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forest sources, for a total of **244 million gallons** of gasoline equivalent.\(^{55}\) It is possible that more cellulosic ethanol from outside the state would also be available.

**Further reading:**

US Department of Energy Biomass Program website:  
[http://www1.eere.energy.gov/biomass/abcs_biofuels.html#prod](http://www1.eere.energy.gov/biomass/abcs_biofuels.html#prod)


US Environmental Protection Agency. EPA Proposes New Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond. [http://www.epa.gov/oms/renewablefuels/420f09023.htm#3](http://www.epa.gov/oms/renewablefuels/420f09023.htm#3)


Figure 1: Processes for Producing Cellulosic Ethanol


Schematic of a Biochemical Cellulosic Ethanol Production Process

Schematic of a Thermochemical Cellulosic Ethanol Production Process
### Biodiesel (FAME\textsuperscript{56}) process

<table>
<thead>
<tr>
<th>Feedstock and production process</th>
<th>Feedstock.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biodiesel is a natural and renewable domestic fuel alternative for diesel engines made from vegetable oils and animal fats. The most common feedstocks for biodiesel are new or used vegetable oils made from crops such as soybean, camelina, rapeseed, canola, palm, cottonseed, sunflower and peanut. Biodiesel can also be made from recycled cooking grease. Most biodiesel made in Oregon is made from waste vegetable oil. In the United States, most biodiesel is produced from soybean oil.\textsuperscript{57}</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Production process.</th>
</tr>
</thead>
<tbody>
<tr>
<td>According to the U.S. Department of Energy, fats and oils are chemically reacted with an alcohol to produce chemical compounds known as fatty acid methyl esters (FAME). Biodiesel is the name given to these esters when they are intended for use as fuel.</td>
</tr>
</tbody>
</table>

Biodiesel can be produced using a variety of esterification technologies. The oils and fats are filtered and preprocessed to remove water and contaminants. If free fatty acids are present, they can be removed or transformed into biodiesel using special pretreatment technologies. The pretreated oils and fats are then mixed with an alcohol (usually methanol) and a catalyst (usually sodium hydroxide). The oil molecules (triglycerides) are broken apart and reformed into methyl esters and glycerin, which are then separated from each other and purified.\textsuperscript{58} 

Biodiesel must meet rigorous ASTM D6751-07b specifications. |

<table>
<thead>
<tr>
<th>Co-products</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glycerin (used in pharmaceuticals and cosmetics, among other markets) is a co-product.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Commercialization status</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fuel.</strong> Biodiesel produced through the FAME process is fully commercialized, and has an annual production capacity of 2.69 billion gallons per year in the United States.\textsuperscript{59}</td>
</tr>
</tbody>
</table>

| Vehícles. **Vehicles.** Biodiesel can be used in unmodified diesel engines with current fueling infrastructure. Performance, storage requirements, and maintenance are similar for biodiesel blends and petroleum diesel. |

Biodiesel has a formal technical definition that is recognized by ASTM International (known formerly as the American Society for Testing and Materials), the organization responsible for providing industry standards. B100 or 100 percent biodiesel must meet ASTM D 6751. Biodiesel blends B6 to B20 must meet ASTM D7467-08 and blends B5 and below must meet the diesel ASTM standard D975.

Like conventional diesel, biodiesel will cloud and gel at very cold temperatures, but blends like B20 are slightly more sensitive than #2 diesel in this respect.

<table>
<thead>
<tr>
<th>Current production in Oregon</th>
<th>Completed Projects(^{60})</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>There are six biodiesel production facilities in Oregon with a total capacity of just over 7 million gallons per year. The majority of the feedstock is waste vegetable oil but some of these plants will process virgin canola, camelina or other seed oils.</td>
</tr>
<tr>
<td></td>
<td>SeQuential Pacific. Salem Oregon, Operating 5.3 million Gal/yr capacity, Feedstocks; waste vegetable oil, canola &amp; camelina</td>
</tr>
<tr>
<td></td>
<td>Beaver Biodiesel. Albany Oregon, Operating 500,000 Gal/yr capacity, Feedstocks; waste vegetable oil</td>
</tr>
<tr>
<td></td>
<td>Evergreen Fuels. Klamath Falls Oregon, Operating 400,000 Gal/yr capacity, Feedstocks; Canola, camelina &amp; waste vegetable oil</td>
</tr>
<tr>
<td></td>
<td>Portland Biodiesel. Portland Oregon, Idle 1 million Gal/yr capacity, Feedstocks; waste vegetable oil</td>
</tr>
<tr>
<td></td>
<td>K &amp; S Madison Farm. Echo Oregon, Operating 20,000 Gal/yr capacity, Feedstocks; Canola Oil</td>
</tr>
<tr>
<td></td>
<td>Lookout Mountain. Prineville Oregon, Seasonal 20,000 Gal/yr capacity, Feedstocks; waste vegetable oil</td>
</tr>
<tr>
<td>Developing Projects</td>
<td></td>
</tr>
<tr>
<td>Willamette Biodiesel. Rickreal Oregon 270,000 Gal/yr capacity, Feedstocks; Seed oils Received a grant of $127,323 from USDA. Estimated opening late 2010</td>
<td></td>
</tr>
<tr>
<td>Potential</td>
<td>Enough virgin soy oil, recycled restaurant grease, and other feedstocks are</td>
</tr>
</tbody>
</table>

\(^{60}\) Rick Wallace, Oregon Department of Energy, personal communication.
production in Oregon | readily available in the United States to provide feedstock for about 1.7 billion gallons of biodiesel per year (under policies designed to encourage biodiesel use). This represents roughly 5% of on-road diesel used in the United States.\textsuperscript{61} \\

Out-of-state production | Regional Biodiesel 
The region outside of our state boasts of biodiesel production capacity well over 140 million gallons per year. Much of this production capacity is currently idle or running under capacity. 
According to the National Biodiesel Board\textsuperscript{62}: 

“There are presently 173 companies that have invested millions of dollars into the development of biodiesel manufacturing plants and are actively marketing biodiesel. The annual production capacity from these plants is 2.69 billion gallons per year. It is important to note that production capacity differs from the actual number of gallons sold. Twenty-nine companies have reported that their plants are currently under construction and are scheduled to be completed within the next 12-18 months. One plant is expanding their existing operation. Their combined capacity, if realized, would result in another 427.8 million gallons per year of biodiesel production.” 

Note: Annual Production Capacity only refers to the reported maximum production capacity of the facility. Therefore, it does not represent how many gallons of biodiesel were actually produced at each plant. In fact, due to current economic conditions, the capacity utilization at many of these facilities is extremely low. 

Current use in Oregon | Volume. There are six biodiesel production facilities in Oregon with a total capacity of just over 7 million gallons per year. 
Use of higher blends of biodiesel, such as B10, B20, B99 or B100 is not tracked. 

Number of vehicles. A Renewable Fuel Standard is a program that increases the volume of renewable fuels to be blended into petroleum fuels. Due to the Oregon renewable fuel standard, all vehicles and equipment, with the exception of marine engines and locomotives, use at least a 2% blend of biodiesel, as of October 1\textsuperscript{st}, 2009\textsuperscript{63}. Use from the Oregon

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\textsuperscript{61} National Renewable Energy Laboratory. Biomass Oil Analysis: Research Needs and Recommendations. 
http://www1.eere.energy.gov/biomass/pdfs/34796.pdf 
\textsuperscript{63} ODA website. ODA Measurement Standards Division. Biofuel renewable fuel standard. 
special issues
Existing fueling infrastructure.

Biodiesel is distributed from the point of production via truck, train, or barge. Pipeline distribution of biodiesel, which would be the most economical option, is still in the experimental phase. However, Kinder Morgan transports a B2 blend of biodiesel (2 percent biodiesel, 98 percent petroleum diesel) in their Portland to Eugene pipeline. Biodiesel produced in Oregon is typically transported by truck. Biodiesel produced out of state, typically soy based biodiesel from the Mid-West is transported by train to Portland terminals and distribution centers. Biodiesel is blended into petroleum diesel at terminals and then transported to smaller distributors and retailers. Higher blends from B10 to B99 of biodiesel are also available in the state. According to the National Biodiesel Board, currently there are 25 distributors and 43 retailers offering high blends of biodiesel in the state of Oregon. Sales of biodiesel in Oregon are hard to determine as the sales are recorded as diesel sales regardless of blend level.

Special issues. Under the federal Renewable Fuel Standard 2 program (See Appendix A on page 78 for details), EPA will require 1 billion gallons of biodiesel and 4 billion gallons of “other advanced biofuels” with a carbon intensity at least 50% less than gasoline or diesel. EPA recognizes that the required volumes could be met with a wide variety of fuel choices, and has developed a projected set of reasonable fuel volumes based on their best estimate of likely fuels that would come to market. They have projected a primary control case, and then two sensitivity control cases (high and low cellulosic ethanol).

Summary of known trends:

<table>
<thead>
<tr>
<th>Volume used</th>
<th>Volume produced</th>
<th>Number of vehicles</th>
</tr>
</thead>
</table>

Trend: volume used.

Trend #1: Biodiesel consumption has increased from an estimated 6.8 million gallons of gasoline equivalent in 2000 to 372 million gallons of gasoline equivalent in 2007.66

Trend #2: Increased required blends. When Oregon’s biodiesel capacity reaches 15 million gallons, all diesel sold in Oregon must contain at least 5% biodiesel. The required volume in Oregon would be

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approximately 26.5 million gallons annually. It is possible that some of this could be met through other biomass-based diesel.\(^{67}\)

There is also potential that in between now and 2022, the City of Portland could increase the required blend within the City of Portland from 5% to 10%.

**Trend: volume produced.**

**Trend #3:** As illustrated by the graph below U.S. production of biodiesel has increased from 9 million gallons in 2001 to over 680 million gallons in 2008.\(^{68}\)

![Gallons of Biodiesel Produced in the United States, 2001-2008](image)

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Future use</td>
</tr>
<tr>
<td>• Low</td>
</tr>
<tr>
<td>• Moderate</td>
</tr>
<tr>
<td>• High</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Future use estimates for biodiesel</th>
</tr>
</thead>
<tbody>
<tr>
<td>A low carbon fuel standard in Oregon could potentially spur more biodiesel production than would have happened otherwise.</td>
</tr>
</tbody>
</table>

**Low estimate (proposed for discussion)**

Based on Oregon’s statutes related to biodiesel blends described in Trend #2, **26.5 million gallons** would be approximately the amount required by the Oregon renewable fuel standard in 2022. This would be a reasonable estimate to bracket the low range of Oregon’s biodiesel production in 2022, although it does not include potential

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increases due to City of Portland regulations. In addition, some of this required volume could be met through use of other type of biomass-based diesel.

**Moderate and High estimates**

Moderate and high estimates of biodiesel availability in Oregon could be based on many different factors, such as:

- Trends in biodiesel production
- Volume available regionally
- Available feedstocks
- Predictions of future use
- Federal Renewable Fuel Standard 2 required volumes for biomass-based diesel

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**Further Reading:**

# Renewable Diesel

(Hydrogenation-Derived Renewable Diesel)

| **Feedstock and production process** | **Feedstock.** Hydrogenation-derived renewable diesel (renewable diesel) is produced from a wide variety of feedstocks, including tallow, poultry fat, trap grease, waste vegetable oil, algal oil, soybean oil, and canola oil. Soybean oil is the most common vegetable oil feedstock for renewable diesel produced in the United States.

**Production process.** Renewable diesel is produced in a conventional petroleum refinery from fats or vegetable oils in a process also known as Fatty Acids to Hydrocarbon Hydrotreatment. Diesel produced in this process is called “renewable diesel” to differentiate it from biodiesel, which is a product of the transesterification of animal fats and vegetable oils. Renewable diesel and biodiesel use similar feedstocks but have different processing methods and create chemically different products. Gasoline can be produced using a similar refining process, but this is in an earlier stage of development. |

| **Co-products** | None. |

| **Commercialization status** | **Fuel.** Renewable diesel is fully commercialized in several areas of the world. In the United States, it is in a transitional stage from pilot and demonstration plants to full-scale commercial production, and not currently widely available. It is likely to become fully commercialized in the near future. A number of producers have commercial trials underway. Blends of up to 100 percent can be used without any modification to existing infrastructure, however cold weather testing beyond a two percent blend has not yet been done.\(^{69}\)

**Vehicles.** Renewable diesel has an identical chemical structure with petroleum-based diesel since it is free of ester compounds. The refined oil can be used alone or combined with petroleum, to replace or complement diesel fuel. Renewable diesel can be used in existing conventional diesel vehicles\(^ {70}\) |

| **Current production in Oregon** | Not currently produced in Oregon. |

| **Potential Production in Oregon** | Oregon does not have an oil refinery. It is unlikely that a refinery will be established in Oregon. However, renewable diesel is compatible with the |

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<table>
<thead>
<tr>
<th>Oregon</th>
<th>existing fuel distribution and storage infrastructure and could be refined in Washington and distributed to Oregon as is - no modifications would be required.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Out-of-state production</td>
<td>A number of manufacturers around the world have developed renewable diesel refining processes, and are now either producing commercial volumes of renewable diesel or constructing commercial facilities. Following are brief descriptions of some of the projects.</td>
</tr>
</tbody>
</table>

**ConocoPhillips (United States, Ireland)**
ConocoPhillips is producing approximately 40,000 gallons per day of renewable diesel at its Whitegate refinery in Cork, Ireland. The primary renewable feedstock is soybean oil, but other vegetable oils and animal fats and oils could be used as well. The renewable diesel is being produced using existing refinery equipment and is blended and transported with petroleum-based diesel.

**Neste Oil (Finland)**
Neste Oil is producing renewable diesel using its NExBTL process from two plants in Finland with a combined capacity of 116 million gallons a year. Two more plants are under construction, one in Singapore and one in the Netherlands, and will come online in 2010 and 2011 respectively, with a combined capacity of 545 million gallons per year.

**UOP-Eni (United States, Italy)**
The first "Ecofining" facility developed by UOP and Italian oil and gas company Eni is scheduled to come online in 2010, processing 273,000 gallons per day of vegetable oils. The U.S. Department of Energy has supported UOP's Renewable Energy and Chemicals unit in developing renewable diesel production technologies.

**Syntroleum (United States)**
Syntroleum formed a joint venture with Tyson Foods to produce renewable diesel and jet fuel using its biofining process. Production from its first plant is expected to be 75 million gallons per year beginning in 2010.

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73 [Neste Annual Report for 2009.](http://www.nesteoil.com/)
74 [UOP website.](http://www.uop.com/renewables/10010.html)
75 [US DOE.](http://www.afdc.energy.gov/afdc/fuels/emerging_green_production.html)
76 [Syntroleum website.](http://www.syntroleum.com/proj_rba_biofining.aspx)
**Darling International and Valero Energy (Louisiana)**
A joint venture between Darling International and Valero Energy will produce 135 million gallons per year of renewable diesel mainly from waste grease and fats.\(^{77}\)

**Tesoro (Washington State)**
Tesoro signed an agreement with AltAir Fuels in December, 2009 to provide renewable jet fuel and diesel to airlines and airport equipment.\(^{78}\)

**Petrobras (Brazil)**
Brazilian oil company Petrobras developed the H-BIO process, which produces renewable diesel using hydrotreating units in existing oil refineries. Petrobras is planning to use the H-BIO process in three of its refineries by 2007 and two more by 2008, with a total vegetable oil consumption of more than 294,000 gallons per day or approximately 100 million gallons per year.\(^{79}\)

### Current use in Oregon

<table>
<thead>
<tr>
<th>Volume</th>
<th>None known at this time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of vehicles</td>
<td>Renewable diesel can be used in existing conventional diesel vehicles.(^{80})</td>
</tr>
<tr>
<td>Existing fueling infrastructure</td>
<td>Renewable diesel can use the existing pipelines, stations and road transport systems for conventional diesel. In addition to the fuel infrastructure, renewable diesel benefits from being able to use the current refinery infrastructure as well.</td>
</tr>
<tr>
<td>Barriers to expansion</td>
<td>Oregon’s lack of oil refining capacity makes the state dependent upon the decisions of refiners outside the state.</td>
</tr>
<tr>
<td>Special issues</td>
<td>Renewable Diesel is a highly stable diesel fuel with a higher cetane number (diesel’s combustion quality) than biodiesel and conventional petrodiesel, suggesting improved vehicle performance and fuel economy. Additionally, its ultra-low sulfur content will reduce emissions.</td>
</tr>
</tbody>
</table>

### Summary of known trends:

<table>
<thead>
<tr>
<th>Volume produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trends in renewable diesel as a transportation fuel</td>
</tr>
<tr>
<td>Volume produced</td>
</tr>
</tbody>
</table>

---


Currently, the three commercial renewable diesel plants in the world have approximately 130 million gallon a year combined capacity. The three additional plants under construction have a combined capacity of 620 million gallons per year, and are expected to be producing in 2010-2011.

Tesoro has proposed a project at an Anacortes refinery to produce renewable diesel and renewable jet fuel.

(Please see the section on Biodiesel (FAME) for trends in biodiesel production and use on page 30)

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
<th>Future use estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Future use</td>
<td>A low carbon fuel standard in Oregon could potentially spur more renewable diesel use for transportation than would have happened otherwise. Trends in other countries or states that use large volumes of renewable diesel could help us identify feasible adoption rates for both passenger and medium/heavy-duty applications.</td>
</tr>
<tr>
<td>• Low</td>
<td></td>
</tr>
<tr>
<td>• Moderate</td>
<td></td>
</tr>
<tr>
<td>• High</td>
<td></td>
</tr>
</tbody>
</table>

**Low estimate (proposed for discussion)**

It is possible that no renewable diesel will be available in Oregon by 2022.

**Moderate estimate (proposed for discussion)**

Because there is a project proposed at a Washington refinery, it is possible that a portion of the planned amount of renewable diesel will be supplied to Oregon by 2022, for example, **25 to 100 million gallons**.

**High (but feasible) estimate (proposed for discussion)**

One or more of the Washington refineries supplying diesel to Oregon could produce renewable diesel and supply it to Oregon by 2022. A commercial volume might be **150-500 million gallons**.
**Fischer-Tropsch and Other Synthetic Fuels**

Fuels produced from the Fischer-Tropsch process are also known as synthetic diesel, synthetic gasoline, and (when made from biomass) cellulosic diesel. Other technologies can also produce synthetic fuel.

<table>
<thead>
<tr>
<th>Feedstock and production process</th>
<th>There are many technologies and production processes that could produce synthetic diesel or even potentially synthetic gasoline. It is outside the scope of this document to cover all of the potential technologies under development. EPA, in their <em>Regulatory Impact Analysis for the Renewable Fuel Standard Program</em> discusses a variety of biofuels production processes.(^{81}) For a list of developing technologies and fuels produced, please see <strong>Appendix B</strong> of this document on page 80.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Feedstock.</strong> Fischer-Tropsch (Fischer-Tropsch) diesel is produced by converting gaseous hydrocarbons called synthesis gas (or “syngas” - a mixture of carbon monoxide and hydrogen produced from biomass or fossil fuels, such as natural gas and gasified coal) into liquid diesel. Additionally some technologies can produce fuel from plastic, tires, and other waste.(^{82})</td>
<td></td>
</tr>
<tr>
<td><strong>Production process.</strong>(^{83}) In 1923, Franz Fischer and Hans Tropsch, scientists at Kaiser Wilhelm Institute, first studied conversion of coal-derived syngas into useful compounds (diesel is one of many chemicals and fuels that can be derived from syngas), using what was to become known as Fischer-Tropsch synthesis. Key to the process are catalysts: substances that facilitate a chemical reaction but are not consumed by the reaction. A schematic of the overall process can be shown in three steps, with each step taking place in the presence of a specific catalyst:</td>
<td></td>
</tr>
<tr>
<td>1. Syngas formation  (Coal or Natural gas or Biomass) + Oxygen → Syngas</td>
<td></td>
</tr>
<tr>
<td>2. Fischer-Tropsch Reaction  Syngas → New Hydrocarbon + Water</td>
<td></td>
</tr>
<tr>
<td>3. Refining  New Hydrocarbon → Fuels, Chemicals, etc.</td>
<td></td>
</tr>
<tr>
<td>The benefit of the process lies in converting a relatively inflexible energy source (such as coal, natural gas or biomass) into a variety of products that meet specific needs. There are Fischer-Tropsch technologies that can...</td>
<td></td>
</tr>
</tbody>
</table>

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http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm  

\(^{82}\) Synthetic Diesel Fuel Production Facility.  

\(^{83}\) US DOE. The Fischer-Tropsch Process.  
http://www.afdc.energy.gov/afdc/fuels/emerging_diesel_process.html  

convert coal-to-liquid (CTL), gas-to-liquid (GTL), and bio-to-liquid (BTL). The latter would mean a less carbon-intensive alternative that could use either agricultural feedstocks or waste biomass materials.

Flash pyrolysis converts biomass into diesel through pyrolysis and hydrotreatment.\(^\text{84}\)

### Co-products
None

### Commercialization Status

**Fuel.** While the Fischer-Tropsch process is a well-proven technology, it requires a large capital investment in equipment followed by high operation and maintenance costs. However, as petroleum prices increase, making synfuels from coal, natural gas, and biomass become more economically competitive. Along with advanced energy companies focusing exclusively on alternative fuels, many oil companies also have dedicated synthetic fuel development programs in place. The production of fuel from biomass through Fischer-Tropsch is not yet fully commercialized. One company has been producing fuel from biomass through flash pyrolysis since 1989.

**Vehicles.** One major benefit of Fischer-Tropsch and other synthetic diesel is their compatibility with currently existing vehicle technologies and fuel distribution systems. Biomass-derived gasoline and diesel could be transported through existing pipelines, dispensed at existing fueling stations, and used to fuel today’s gasoline- and diesel-powered vehicles on their own or as a blendstock.

### Current Production in Oregon
Not currently produced in Oregon.

### Potential Production in Oregon
See the Oregon Biomass Assessment report prepared for the April 15, 2010 Advisory Committee meeting for information on Oregon’s potential for producing biomass. ([http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm](http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm))

### Out-of-state Production
Fischer-Tropsch production was commercialized in Germany in 1936 to take advantage of coal-rich reserves and accounted for an estimated 9% of German war production of fuels and 25% of the automobile fuel during World War II.

To enhance energy independence in the face of apartheid-related economic isolation embargoes, Sasol in South Africa satisfied most of its diesel

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demand with natural gas- and coal-derived Fischer-Tropsch diesel for decades and is still using the fuel in significant quantities.

One of the largest implementations of Fischer-Tropsch technology is in Bintulu, Malaysia. This Shell facility converts natural gas into low-sulfur diesel fuels and food-grade wax. The scale is 12,000 barrel/day.

In the United States, Fischer-Tropsch diesel has been used in demonstration projects. In Pennsylvania, Waste Management and Processors Inc. was funded by the state to implement Fischer-Tropsch technology licensed from Shell and Sasol to convert so-called waste coal (leftovers from the mining process) into low-sulfur diesel fuel.

Many oil companies such as Shell Oil, Chevron (Texaco), and ExxonMobil have been conducting research and have built pilot plants or smaller commercial plants. In conjunction with several private sector organizations, National Energy Technology Laboratory built and operated a pilot plant in LaPorte, Texas, focusing on the development of slurry-phase reactor technology.\(^85,86\)

Rentech anticipates completing its 640 barrels-per day commercial facility in Rialto, California by 2012.\(^87\)

Ensyn Corp’s commercial plant in Ottawa, Canada has been producing fuel from residual wood through flash pyrolysis since 1989.\(^88\)

<table>
<thead>
<tr>
<th>Current Use in Oregon</th>
<th>Volume</th>
<th>Not applicable.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Number of vehicles</td>
<td>Not applicable.</td>
</tr>
<tr>
<td></td>
<td>Existing fueling infrastructure</td>
<td>Fischer-Tropsch fuels can use the existing pipelines, stations and road transport systems as a conventional diesel and gasoline or as a blendstock with diesel or gasoline.</td>
</tr>
<tr>
<td></td>
<td>Barriers to expansion</td>
<td>Developing a commercial scale production process.</td>
</tr>
<tr>
<td></td>
<td>Special issues</td>
<td>Under the federal Renewable Fuel Standard 2 program (See Appendix A on page 78 for details), EPA will require 16 billion gallons of cellulosic biofuels with a carbon intensity at least 60% less than gasoline or diesel, and 1 billion gallons of biodiesel and 4 billion gallons of “other advanced biofuels” with a carbon intensity at least 50%</td>
</tr>
</tbody>
</table>

less than that of gasoline or diesel. Diesel produced from biomass through the Fischer-Tropsch process could fit into any of these categories. EPA recognizes that the required volumes could be met with a wide variety of fuel choices, and has developed a projected set of reasonable fuel volumes based on their best estimate of likely fuels that would come to market. They have projected a primary control case, and two sensitivity control cases (high and low cellulosic ethanol).

<table>
<thead>
<tr>
<th>Summary of known trends:</th>
<th>Trend: volume used. None in Oregon.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trend: volume produced. None in Oregon.</td>
</tr>
<tr>
<td></td>
<td>Trend: number of vehicles. Not applicable.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
<th>Future use estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume produced</td>
<td>Due to the federal Renewable Fuel Standard 2, higher volumes of lower carbon biofuels will be required.</td>
</tr>
<tr>
<td>Volume used</td>
<td>A low carbon fuel standard in Oregon could potentially spur Fisher-Tropsch and other synthetic diesel fuel production. Trends in other countries or states produce Fisher-Tropsch and other synthetic diesel fuels could help us identify feasible future production.</td>
</tr>
<tr>
<td>Number of vehicles</td>
<td>Low estimate (proposed for discussion)</td>
</tr>
<tr>
<td></td>
<td>EPA’s Primary Control Case (for the Renewable Fuel Standard Program) predicts there will be an estimated 6.52 billion gallons of cellulosic diesel in 2022. Based on Oregon’s consumption of gasoline and diesel compared to the United States, Oregon’s share of this is 77 million gallons.</td>
</tr>
<tr>
<td></td>
<td>Moderate Estimate (proposed for discussion)</td>
</tr>
<tr>
<td></td>
<td>EPA’s Low Ethanol Case (for the Renewable Fuel Standard Program) predicts there will be an estimated 9.26 billion gallons of cellulosic diesel in 2022. Based on Oregon’s consumption of gasoline and diesel compared to the United States, Oregon’s share of this is 110 million gallons.</td>
</tr>
<tr>
<td></td>
<td>High (but feasible) estimate (proposed for discussion)</td>
</tr>
</tbody>
</table>

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Based on the commercialization status of Fischer-Tropsch and other synthetic diesel fuels, it is possible that commercial scale facilities (150-300 million gallons) could be built and producing fuel by 2022.

**Further Reading:**


**Electricity**

**Feedstock and production process**

**Feedstock.** Electricity production uses a diverse spectrum of primarily domestic based energy sources. The common sources for electricity used in Oregon are hydropower, coal, natural gas, nuclear, wind, biomass, geothermal and solar. Technologies for the production of electricity from other sources, such as wave energy, are being researched but are not yet commercialized.

**Production process.** Electricity is a form of energy converted from other sources of energy listed above. It is most commonly produced using a source of heat to create steam to drive turbines connected to electromagnetic generators. It is also produced by driving turbines mechanically as occurs in hydroelectric and wind power projects. Less commonly, electricity can be generated directly from solar energy using photovoltaic cells.

**Co-products**

Not Applicable.

**Commercialization status**

- **Fuel.** Technology for many sources of electrical production (e.g. coal and hydropower) are fully established while others (e.g., wind, solar, geothermal etc.) continue to be developed. The electrical grid used to distribute this energy is fully established throughout the country.

Unlike many proposed alternative fuels, electricity already has a large network delivery system in place. The power sector is constructed to be able to meet peak demand. However, throughout a 24 hour day, the grid can supply significantly more energy than is currently required. This spare capacity could be used in the transportation sector.

Additional infrastructure could be needed to supply electricity for transportation, such as public charging stations, increased investments in grid reliability, and smart grid technology.

- **Vehicles.** Electric vehicles come in several different forms. The two major categories are pure electric vehicles and plug-in hybrid electric vehicles. In the case of plug-in hybrid electric vehicles, the vehicle will incorporate both an electric motor and an internal combustion engine, which runs on petroleum fuel.

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Electric vehicles have been around for over a hundred years but have not become mainstream due to range and speed limitations. New battery technology is changing the range and speed of electric vehicles. These new technologies are currently expensive, but with mass production, costs could come down.

Light-duty (passenger) electric vehicles are on the verge of wide commercialization. Nine full-function electric vehicles or plug-in vehicles are due to be launched by 2011 (in addition to low-speed and neighborhood vehicles).

Four heavy-duty plug-in vehicles are currently available with two more coming to market in 2010. For some applications, such as forklifts, there are many models available.

| Current production in Oregon | Production/Providers. | Three investor-owned utilities, three energy service suppliers, and 36 consumer-owned utilities supply electricity in Oregon. The five main providers of electricity in Oregon are the investor owned utilities Portland General Electric (PGE) and Pacific Power (a PacificCorp company), the city of Eugene, the electricity services supplier Sempra Energy Solutions, and the Central Lincoln People’s Utility District. The two main sources of electricity in Oregon are hydropower and coal, but natural gas is playing an increasing role.

Oregon’s electricity resource mix for 2007 (the most recent year available) was 43.2 percent hydro, 37.8 percent coal, 14.1 percent natural gas, 3.2 percent nuclear, 1.5 percent wind and geothermal, and 0.3 percent biomass. |

| Potential production in Oregon | Potential production. | Oregon has seen growth in renewable electricity production in the last several years. To ensure continued growth in clean energy, the legislature passed the Oregon Renewable Energy Act of 2007. The state of Oregon established a renewable portfolio standard for electric utilities and retail electricity suppliers, which requires that all utilities and electricity service suppliers serving Oregon include a percentage of electricity generated from qualifying renewable energy sources in their source mix. The percentage of qualifying electricity that must be included varies over time, with all utilities and electricity service suppliers obligated to include some renewably generated electricity in their portfolio by the year 2025.⁹²

Oregon has potential for future electricity generation from low carbon sources such as wind, geothermal, biomass and solar. Many of the scenarios for implementing these technologies include natural gas. |

facilities to provide backup power generation.

<table>
<thead>
<tr>
<th>Out-of-state production</th>
<th><strong>Out-of-state Production.</strong> Oregon is connected to a large regional grid network that can transport electricity in and out of the state. Electricity comes from many sources out-of-state such as coal, hydro, nuclear, and renewable and natural gas.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current use in Oregon</td>
<td><strong>Volume.</strong> There are no reliable figures on current volume of electricity used for transportation purposes. Due to the small number of electric vehicles currently in use, the volume of electricity they consume is insignificant compared to the volume used for non-transportation purposes.</td>
</tr>
<tr>
<td></td>
<td><strong>Number of vehicles.</strong> Over 40,000 electric vehicles and plug-in hybrid electric vehicles are currently used in the United States and just over 400 are registered with the DMV in Oregon. This number does not include non-road equipment and vehicles. The EIA estimates that in 2007, there were 1,636 electric vehicles in use in Oregon. Many of these are used in fleet applications, from maintenance to checking parking meters; these electric vehicles are mostly limited to 25 mph speed and 20-mile range. A growing number of electric vehicles are coming to market are of a new generation of freeway-speed electric vehicles that will be available to the mass consumer market in 2010. Electric vehicles have also been introduced at the high end of the market with the introduction of the Tesla Roadster. Battery technology has improved dramatically and full-function electric vehicles are poised for rapid expansion into Oregon. Many auto manufacturers will be introducing electric vehicles and plug-in hybrid electric vehicles beginning in late 2010. Virtually every major auto manufacturer in the world, along with numerous smaller companies, is developing electric vehicles or plug-in hybrid electric vehicles.</td>
</tr>
<tr>
<td></td>
<td><strong>Existing fueling infrastructure.</strong> Most electric vehicles can be charged from a standard U.S. 120 volt outlet. However, recharge times at this voltage are fairly long. For some electric vehicles, it could take 8 to 14 hours to charge the car from empty to full. The technology exists for charging much more quickly at 220 volts (2-6 hours) and 480 volts (under 1 hour). These are called “level 2” and “level 3” charging stations, respectively. Currently there are just over 30 public electric vehicle-charging stations in Oregon with new ones added on an almost monthly basis. It is expected that “level 2” charging will be the norm for charging full battery electric vehicles.</td>
</tr>
</tbody>
</table>

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93 Rick Wallace, Oregon Department of Energy, personal communication.
On August 5, 2009, Electric Transportation Engineering Corporation (eTec), a subsidiary of ECOtality, Inc., was selected by the U.S. Department of Energy as the project manager for a program to accelerate the development and production of various electric drive vehicle systems to substantially reduce petroleum consumption. The grant is valued at approximately $99.8 million to undertake the largest deployment of electric vehicles and charging infrastructure in U.S. history.\textsuperscript{96}

The project takes advantage of the early availability of the Nissan LEAF, a zero-emission light-duty passenger electric vehicle, to develop, implement and study techniques for optimizing the effectiveness of charging infrastructure that will support widespread electric vehicle deployment. The project will install electric vehicle charging infrastructure and deploy Nissan battery electric vehicles in strategic markets in five states: Arizona, California, Oregon, Tennessee, and Washington.

The Oregon effort will monitor just under one thousand vehicles and the infrastructure to recharge them at their home as well as over 1,250 public level 2 and 50 fast charging station (level 3) charging stations. The project will install and monitor the infrastructure in Portland, Salem, Corvallis and Eugene.

It is expected that additional charging infrastructure will be installed, due to current state and federal incentives that can pay for up to 85 percent of the costs.

In terms of grid capacity available for charging electric vehicles, a 2007 study from the U.S. Department of Energy’s Pacific Northwest National Lab looked at the regional percentage of the passenger car light-duty fleet which could be replaced with plug-in hybrid electric vehicles supplied with energy from the existing power system without additional investments in generation, transmission and distribution. To estimate the unused generation capability that would be available for plug-in hybrid electric vehicles, they looked at the total capacity minus the hourly generation that is committed to meeting load demand. The study did not include hydroelectric, nuclear or renewable plants in its estimates. The unused generation was further curtailed by accounting for scheduled maintenance; other planned outages and by precluding the use of peaking plants designed for short run-time operations. The study concluded that although the Pacific Northwest had less unused power than other regions

\textsuperscript{96} Oregon Department of Transportation (ODOT) website. Innovative Partnerships Program. http://www.oregon.gov/ODOT/HWY/OIPP/inn_ev-charging.shtml
of the United States, there is unused power that could power between 1.6 and 2.8 million plug-in hybrid electric vehicles in Oregon.97

**Barriers to expansion.**

**Product barriers.** Battery costs are the most significant product-related barrier. Although nearly every automaker has announced plans to make electric vehicles, the battery industry does not currently have sufficient production capability to achieve economies of scale. A tremendous amount of research and development investment will be going into battery technology in the next few years and will likely parallel what has happened to computer memory in the last decade, with each successive generation becoming smaller, lighter, less expensive and able to hold more energy. Until then, early adopters will be paying a significant premium over comparable internal combustion vehicles.

In addition, there are currently few vehicle choices, especially for moderately priced vehicles and for large capacity vehicles like trucks, minivans, buses and SUVs.

**Distribution Barriers.** Utilities must be able to handle the potential increase in total demand, daily peak loads and other challenges. While electric vehicles are inherently simpler than internal combustion vehicles, there are currently very few auto mechanics and technicians trained to work on them.

**Infrastructure Barriers.** Electric vehicle owners currently face challenges in finding convenient public charging stations. A reliable infrastructure for charging is an absolute necessity to encourage growth and acceptance. Public investment might be necessary to help build sufficient public charging infrastructure due to the low cost of electricity. Fast charging can be expensive to install. The Society of Automotive Engineers is still developing standards for some charging technologies.

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<table>
<thead>
<tr>
<th>Summary of known trends:</th>
<th>Trends in Electricity as a transportation fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Volume used</td>
<td>Volume used</td>
</tr>
<tr>
<td>• Number of vehicles</td>
<td><strong>Trend #1:</strong> In Oregon, current use of electricity in vehicles and equipment is approximately 1,636 electric vehicles.98</td>
</tr>
<tr>
<td></td>
<td><strong>Trend #2:</strong> In the United States, consumption of electricity as a</td>
</tr>
</tbody>
</table>

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transportation fuel has increased 1.2 million gallons of gasoline equivalent in 1998 to 5 million gallons of gasoline equivalent in 2007.99

**Number of vehicles**

**Trend #3:** In the United States, the number of electric vehicles in use increased substantially. In 2007, there were over 12 times as many electric vehicles on the road as there were in 1997.100

**Trend #4:** Oregon Zero Emission Vehicle rules will increase the minimum number of electric or plug in hybrid electric vehicles sold in Oregon. Vehicle rules, a minimum of approximately 12,000 full battery electric vehicles and 17,000 plug-in-hybrid electric vehicles must be placed in Oregon in by 2022.101

### Preliminary Estimates of 2022 Use:
- **Future use**
- **Low**
- **Moderate**
- **High**

### Future use estimates

**Forecast #1:** It is difficult to base predictions of future use of electricity on past use of electricity as a transportation fuel because the technology has changed and will continue to change. In the past, available electric vehicles were limited in speed and range. New electric vehicles are freeway ready, have longer ranges, and consequently use more electricity and have more potential for use as a transportation fuel.

**Forecast #2:** The U.S. Energy Information Administration predicts that electricity used as a transportation fuel will increase for light duty vehicles, particularly for plug-in gasoline hybrids. They predicted a decline in full-battery electric vehicles. Their estimate of future use is only slightly higher than the historic rate of electric vehicles use (15% average per year). Based on this information, electricity use in light-duty transportation would be 5.54 trillion Btus in 2022.102

**Forecast #3:** It is likely that plug-in hybrid electric vehicles will be more popular than pure electric vehicles due to range anxiety and battery cost.

**Forecast #4:** A low carbon fuel standard in Oregon could potentially spur more electricity use for transportation than would have happened otherwise. Trends in other countries or states that use large volumes of electricity could help us identify feasible adoption rates for both passenger and medium/heavy-duty applications.

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**Low estimate (proposed for discussion)**

Based on Oregon’s Low Emission Vehicle rules, a minimum of approximately 12,000 full battery electric vehicles and 17,000 plug-in-hybrid electric vehicles must be placed in Oregon in by 2022.\(^\text{103}\)

**Moderate and High estimates (proposed for discussion)**

Moderate and high estimates could be based on future electric vehicle predictions from academics, governments, consultants, or auto manufacturers.

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**Further reading:**

**University of Berkeley, CA. Electric Vehicles in the United States: A New Model with Forecasts to 2030.** Center for Entrepreneurship & Technology (CET) Technical Brief. Number: 2009.1.v.2.0

**Electrification Coalition: Electrification Roadmap.**

**Pike Research:** Electric Vehicles: 10 Predictions for 2010.
http://www.pikerresearch.com/research/electric-vehicles-10-predictions-for-2010

**Green Car Institute.** The Current and Future Market for Electric Vehicles.

**McKinsey & Company. The Current and Future Market for Electric Vehicles.**


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\(^{103}\) Dave Nordberg, ODEQ. Minimum Number Electric Vehicles Required in Oregon by ZEV Rules, 4/5/2010.
### Compressed Natural Gas (CNG) - Fossil Sources

**Feedstock and production process**

**Feedstock.** Natural gas consists of a mixture of hydrocarbons, predominantly methane (CH₄). Most natural gas is extracted from gas and oil wells via drilling, and then processed to remove impurities and bring it to pipeline quality specifications. Smaller amounts are derived from sources such as synthetic gas, coal-derived gas, and landfill gas and other biogas resources. (Biogas as a source of CNG and LNG is addressed in a separate fuel assessment on page 62.)

**Production process.** To produce compressed natural gas, natural gas must first be upgraded to pipeline quality by removing impurities such as water, sulfur, carbon dioxide, oils and other condensates, and natural gas liquids. After it is upgraded, natural gas can be compressed to approximately 3,600 pounds per square inch for use as a transportation fuel.

**Co-products**

Not applicable.

**Commercialization status**

- **Fuel**
- **Vehicles**

**Fuel.** Production and distribution of natural gas is a mature industry in the United States. Oregon is tied into a vast natural gas pipeline distribution system in North America. Natural gas accounts for approximately one quarter of the energy used in the United States. Of this, the bulk of natural gas goes to residential, commercial, industrial, and electric power production. Only about one tenth of one percent is currently compressed and used as a transportation fuel.¹⁰⁴

**Vehicles.** Natural gas vehicle technology is fully commercialized for both light and heavy-duty applications, and compressed natural gas vehicles are widely available in most regions of the world. However, the vehicles are more widespread in other parts of the world than in the United States. Europe, Latin America, and the Middle East have experienced strong growth in compressed natural gas use in the transportation sector. Recently, several large United States companies, such as, AT&T, UPS and PG&E have committed to incorporating thousands of natural gas vehicles into their fleets. According to the Natural Gas Vehicle Institute¹⁰⁵, there are over 50 manufacturers of CNG vehicles and over 150 models worldwide, with 8.4 million CNG vehicles on the road worldwide and roughly 130,000 in the United States.

There are numerous options for medium-duty transportation uses such as transit buses, school buses, step-vans, and trucks.¹⁰⁶ However, there are

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few natural gas light-duty passenger cars and trucks available in the United States. Some existing vehicles can be converted to run on CNG.

Cost is one of the chief factors driving the use of compressed natural gas as a transportation fuel. According to Natural Gas Vehicles of America, natural gas has been 25-42 percent cheaper than diesel over the last 14 years and on average costs more than one-third less than conventional gasoline at the pump. Additionally, CNG costs to the end user are less volatile than gasoline or diesel due to regulation of natural gas prices by the Oregon Public Utilities Commission. The economic advantage of CNG over gasoline has been steadily increasing as new technology to extract natural gas has created vast new recoverable reserves in the United States. If gasoline prices increase, CNG could experience an increase in use.

| Current production in Oregon | Oregon’s natural gas is supplied by three providers: Avista, Cascade Natural Gas and NW Natural. The vast majority is imported, and arrives in gaseous form via pipeline. Some natural gas is liquefied and stored for regasification and use during peak heating months. In 2007, Oregon had 18 wells producing 409 million cubic feet of natural gas annually. Total natural gas delivered to Oregon was 242,393 million cubic feet according to the Energy Information Agency. Hence, gas produced in Oregon in 2007 was only two tenths of a percent of the gas used in Oregon. |
| Potential production in Oregon | Oregon does not have substantial natural gas reserves, although more Oregon production is possible. |
| Out-of-state production | Most natural gas consumed in the United States is domestically produced, with significant imports from Canada. New drilling technologies have unlocked new natural gas reserves from several sources such as shale, deep natural gas, coalbed methane and tight natural gas. The nation’s reserves have surged by 35 percent recently, accounting for the largest increases in history. While we import approximately 57 percent of our oil, 98 percent of natural gas used in the United States comes from North America, and by 2030, it is estimated that 98 percent will come from United States reserves alone. A recent study concluded that the United States has 118 years worth of natural gas resources at current production levels. Additionally, in 13 of the past 14 years, the amount of new natural gas discovered in the United States has been greater than the amount consumed in that year.

Current use
- Volume
- Number of vehicles
- Existing fueling infrastructure
- Barriers to expansion
- Special issues

<table>
<thead>
<tr>
<th>Description</th>
<th>Details</th>
</tr>
</thead>
</table>
| Volume.     | In Oregon, the trend is for increased use of CNG as a transportation fuel. From 2004 to 2008, use of natural gas as a transportation fuel doubled from 96 million cubic feet to 190 million cubic feet.  
| Number of vehicles. | There are 400 registered highway CNG vehicles in Oregon. According to the Energy Information Administration, in 2007 there were 1,500 CNG vehicles and equipment in Oregon. Currently the state of Oregon motor pool has the largest fleet of CNG vehicles with approximately 160 vehicles.  
| Existing fueling infrastructure. | Oregon currently has CNG refueling infrastructure at several locations along the I5 corridor. However, most of this infrastructure is inaccessible to the general public.  
| Medford: | Jackson county and Rogue Valley Transit District currently have CNG compressors, but hope to build a new regional fueling station in White City using modern fast fill technology. Jackson County and Rogue Valley Transit District pumps in Medford provide the only publicly accessible CNG in Oregon. Recently the City of Medford received a grant to purchase a CNG powered street sweeper. The local natural gas provider, Avista, also has a CNG powered fleet with refueling capabilities but is unable to allow public refueling due to Public Utility Commission rules.  
| Springfield: | Fueling stations at the former state of Oregon motor pool facility in Springfield is still operational and currently being rented by the University of Oregon.  
| Salem: | Salem has two compressor stations:  
  - Oregon Department of Administrative Services Motor Pool. The legislature passed a bill (HB 3676) during the last session that sunsets in 2014 and allows the sale, distribution and dispensing of compressed natural gas to private entities.  
  - Salem Keizer Transit District facility. On some occasions, the transit facility has allowed fueling stops by outside vehicles.  

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111 US EIA. Data from 2007. Natural Gas Consumption by End Use, Annual, for Oregon.  
[http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm](http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm).  
customers, but generally does not offer public refueling.

- **Portland area:** The closed Portland area state motor pool site is operating as a cardlock. The Port of Portland has a compressor to refuel buses and other equipment but does not offer public refueling. NW Natural has some refueling capabilities but they are not suitable for public access and they have the same limitation as Avista in offering public refueling. A public refueling facility in Hillsboro recently closed due to economic reasons.

**Barriers to expansion.** For light-duty passenger car applications, CNG refueling infrastructure is the barrier to market adoption vehicles. A metropolitan network of compressors and dispensers with card lock public access are required to give consumers options for refueling CNG vehicles. Investors are reluctant to pursue these opportunities without guaranteed markets developing. Consumers are reluctant to pursue home refueling appliances due to initial cost and lack of locations to refill their vehicles away from home.

For medium and heavy-duty applications, capital expense for a large fleet CNG system (including compression, storage and card lock dispensers) is in the range of $500,000 to $1 million, depending on the amount of fuel needed at any given time. Such a system would displace from 0.5 to 1 million gallons of diesel annually. The highest cost-to-benefit ratio is seen in large fleets that return to base, such as buses, waste haulers, taxicabs, distributors, delivery vehicles and some corporate fleets. These captive fleets are the key and basis to deployment of CNG infrastructure.

**Special issues: paving the way for Fuel Cell Vehicles.** Natural gas vehicle and infrastructure development could facilitate the transition to fuel cell technology. As gaseous fuels, natural gas and hydrogen share issues related to fuel storage, fueling infrastructure, station siting and public acceptability. Vehicles fueled with hydrogen-natural gas blends could be an intermediate step toward a hydrogen-based transportation network.

<table>
<thead>
<tr>
<th>Summary of known trends:</th>
<th>Volume used</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Volume used</td>
<td>Trend# 1: In Oregon, use of compressed natural gas as a transportation fuel increased over 200% from 2004 to 2008.¹¹³</td>
</tr>
<tr>
<td>• Number of vehicles</td>
<td>Trend# 2: In the United States, consumption of compressed natural gas as a transportation fuel increased 169% in the decade from 1997 to 2007.</td>
</tr>
</tbody>
</table>

¹¹³ US EIA. Data from 2004-2008. Data were not available for previous years. Natural Gas Consumption by End Use, Annual, for Oregon. [http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm](http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm).
During that same timeframe, use of CNG increased an average of 11% per year.\textsuperscript{114}

**Number of vehicles**

**Trend #3:** In the United States, the number of CNG vehicles in use increased approximately 5% per year from 1997 to 2007.\textsuperscript{115}

**Trend #4:** Worldwide, there are over 7 times more CNG vehicles on the road in 2008 than in 2007.\textsuperscript{116}

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
<th>Future use estimates</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Future use</strong></td>
<td>Forecast #1: The Energy Information Administration\textsuperscript{117} predicts that CNG use in light-duty passenger vehicles will decline slightly. They also predict that by 2020:</td>
</tr>
<tr>
<td><strong>Low</strong></td>
<td>a. Transit bus use of CNG will nearly triple</td>
</tr>
<tr>
<td><strong>Moderate</strong></td>
<td>b. School bus use of CNG will double</td>
</tr>
<tr>
<td><strong>High</strong></td>
<td>c. Medium-duty truck use of CNG will more than double</td>
</tr>
<tr>
<td></td>
<td>d. Heavy-duty truck use of CNG will be nine times higher than in 2007</td>
</tr>
<tr>
<td></td>
<td>Forecast #2: A low carbon fuel standard in Oregon could potentially spur more CNG use for transportation than would have happened otherwise. Trends in other countries or states that use large volumes of CNG could help us identify feasible adoption rates for both passenger and medium/heavy-duty applications.</td>
</tr>
<tr>
<td></td>
<td><strong>Low estimate (proposed for discussion)</strong></td>
</tr>
<tr>
<td></td>
<td>A low estimate could be based on the historic rate of increase for CNG use in Oregon or the US, or on future predictions. Most of the increase would likely be in the medium-duty vehicle range.</td>
</tr>
<tr>
<td></td>
<td><strong>Moderate and High estimates (proposed for discussion)</strong></td>
</tr>
<tr>
<td></td>
<td>Moderate and high estimates could be based on several different sources of information, such as future electric vehicle predictions from consultants, natural gas associations, government or natural gas vehicle manufacturers.</td>
</tr>
</tbody>
</table>

\textsuperscript{114} US DOE. Alt Fuels & Advanced Vehicles Data Ctr. \url{http://www.afdc.energy.gov/afdc/data/fuels.html}

\textsuperscript{115} US DOE. Alt Fuels & Advanced Vehicles Data Ctr. \url{http://www.afdc.energy.gov/afdc/data/vehicles.html}

\textsuperscript{116} International Association for Natural Gas Vehicles website. Vehicle Statistics. \url{http://iangv.org/tools-resources/statistics.html}

\textsuperscript{117} US EIA. Annual Energy Outlook 2010. Supplemental Tables. Table 46. \url{http://www.eia.doe.gov/oiaf/aeo/supplement/}
Further reading:

California Energy Commission. Compressed Natural Gas (CNG) As A Transportation Fuel. [Link]

Natural Gas Vehicles for America:

- Fact Sheet: Potential Contribution of NGVs to Displacing 35 Billion Gallons of Non-Petroleum Fuels by 2017. [Link]
- The Case For Natural Gas: The Most Abundant, Clean And Cost-Efficient American Fuel. An Issue Brief. [Link]

### Liquefied Natural Gas (LNG) - Fossil Sources

#### Feedstock and production process

**Feedstock.** Natural gas consists of a mixture of hydrocarbons, predominantly methane (CH\(_4\)). Most natural gas is extracted from gas and oil wells via drilling, and then processed to remove impurities and bring it to pipeline quality specifications. Much smaller amounts are derived from sources such as synthetic gas, landfill gas and other biogas resources, and coal-derived gas. (Biogas as a source of CNG and LNG is addressed in a separate fuel assessment on page 62.)

**Production process.** To produce liquefied natural gas, or LNG, natural gas is purified and condensed into liquid by cooling to -260°F (-162°C). Because it must be kept at such cold temperatures, LNG is stored in double-wall, vacuum-insulated pressure vessels.

It is important to distinguish between LNG as a bulk commercial product, and LNG for use as a transportation fuel. The LNG that is ultimately used in a vehicle may or may not have been liquefied at a previous stage in its distribution. The three main distribution chain scenarios are:

- Extraction site (North America) —> Pipeline —> LNG fueling station
- Extraction site (overseas) —> Liquefaction (overseas) —> Tanker —> Re-gasification (U.S.) —> Pipeline —> LNG fueling station
- Extraction site (overseas) —> Liquefaction (overseas) —> Tanker —> Tank truck —> LNG fueling station

This paper addresses LNG used in vehicles and equipment as a transportation fuel.

#### Co-products

Not applicable.

#### Commercialization status

**Fuel.** Production and distribution of natural gas is a mature industry in the U.S., and Oregon is tied into a vast natural gas pipeline distribution system in North America. Natural gas liquefaction technology is fully commercialized, although the use of LNG vehicle fueling stations is not widespread on the west coast outside of a few locations, including the Southern California.

**Vehicles.** LNG vehicle technology is fully commercialized for heavy-duty applications such as refuse haulers, local delivery and transit buses, and LNG vehicles are widely available for purchase in most regions of the United States.

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LNG vehicles are typically original equipment manufacturer modified for this fuel use. There are no light-duty passenger LNG vehicles available in the US.

| Current production in Oregon | LNG is not commercially transported or sold in Oregon at this time. Currently the only use of LNG in Oregon is by natural gas providers in order to reduce its storage volume until it is needed during peak heating months.  
(See CNG Fuels Assessment for information about Oregon’s current natural gas production on page 52.) |
| Potential production in Oregon | (See CNG Fuels Assessment for information about Oregon’s potential natural gas production on page 52.) |
| Out-of-state production | Currently, most natural gas arrives in Oregon in gaseous form via pipeline. (See CNG Fuels Assessment for information about out-of-state natural gas supplies.) Transportation use as LNG from the gas that arrives via pipeline would require liquefaction.  
The U.S. currently imports a small portion of its natural gas supplies as LNG, mainly from Africa and the Middle East. In the future, LNG could arrive in Oregon by sea on specialized tankers with insulated walls. It would then be transported in a liquefied form, or re-gasified, transported over land by pipeline, and re-liquefied at a fueling station. |

| Current use | Volume. LNG is not currently used as a transportation fuel in Oregon.  
Number of vehicles. None in Oregon.  
Existing fueling infrastructure. None in Oregon.  
Barriers to expansion. LNG refueling infrastructure is the barrier to market adoption of LNG vehicles. A fueling station costs approximately $1 million dollars. Manufacturers build vehicles and could provide fueling infrastructure if there were a demand in our market. Fleets might consider the fuel if the infrastructure was available locally. |
| Summary of known trends: Volume used  
Number of | Trends in Liquefied Natural Gas as a transportation fuel |

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119 California Energy Commission: Liquefied Natural Gas (LNG) as a Transportation Fuel  
http://www.consumerenergycenter.org/transportation/afvs/lng.html
vehicles | Volume used
---|---
| Trend #1: In the United States, consumption of liquefied natural gas as a transportation fuel has increased 648% in the decade from 1997 to 2007.\(^{120}\)

Number of vehicles

| Trend #2: In the United States, the number of LNG vehicles in use increased approximately 350% from 1997 to 2007.\(^{121}\)

**Preliminary Estimates of 2022 Use:**

- **Future use**
  - **Low**
  - **High**

**Future use**

**Forecast #1:** If Oregon followed U.S. trends, LNG could play an integral role in future transportation fuel use.

**Forecast #2:** Other countries and areas of the U.S. are investing in LNG infrastructure and vehicles.\(^{122}\)

**Forecast #3:** If there were either government or private investment in LNG infrastructure, LNG could become an important contributor to transportation in Oregon.

**Forecast #4:** A low carbon fuel standard in Oregon could potentially spur more LNG use for transportation than would have happened otherwise. Trends in other countries or states that use large volumes of LNG could help us identify feasible adoption rates for medium- and heavy-duty applications.

**Low estimate (proposed for discussion)**

It is possible, due to lack of infrastructure and historic use, that no LNG will be used for transportation purposes in Oregon.

**High (but feasible) estimate (proposed for discussion)**

Based on the historic use and lack of fueling infrastructure, DEQ proposes not to include any LNG in the compliance scenarios for the low carbon fuel standard.

In the event that LNG is used in Oregon for transportation, LNG would be assigned a carbon intensity and could participate in the low carbon fuel standard as any other fuel would. In addition, the rules will

\(^{120}\) US DOE. Alt Fuels & Advanced Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/data/fuels.html](http://www.afdc.energy.gov/afdc/data/fuels.html)

\(^{121}\) US DOE. Alt Fuels & Advanced Vehicles Data Ctr. [http://www.afdc.energy.gov/afdc/data/vehicles.html](http://www.afdc.energy.gov/afdc/data/vehicles.html)

address LNG, as we have discussed in past advisory committee meetings.

Further reading:

Environmental Protection Agency
http://www.afdc.energy.gov/afdc/pdfs/epa_lng.pdf

http://www.energy.ca.gov/lng/faq.html

California Energy Commission: Liquefied Natural Gas (LNG) as a Transportation Fuel
http://www.consumerenergycenter.org/transportation_not_applicable.fvs/lng.html
**Biogas (Biomethane)**

<table>
<thead>
<tr>
<th>Feedstock and production process</th>
<th>Feedstock. Biogas (also referred to as biomethane) is produced from the biological breakdown of biodegradable organic materials (anaerobic digestion), resulting in a mixture of methane, carbon dioxide, and trace amounts of other gases. Biogas captured from landfills is referred to as landfill gas (raw landfill gas is about 50% methane), while digester gas (from 55% to 80% methane) refers to the production of biogas from wastewater treatment plants (sewage), and livestock manure, food waste, industrial waste, and other sources. Biogas is either flared off (burned) resulting in no capture of energy, combusted for electricity generation or heating, or refined into pipeline-quality gas. Biogas can be compressed and used as a transportation fuel in CNG vehicles, or used as a liquefied gas, or converted to hydrogen.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Co-products</td>
<td>By-products from anaerobic digestion can include fertilizers.</td>
</tr>
<tr>
<td>Commercialization status</td>
<td><strong>Fuel.</strong> As active landfills must control landfill gas as environmental and health safety precaution, landfill gas collection systems using a network of wells, headers, and blowers to collect and route the gas to flaring or treatment are well established. The conversion of landfill gas to CNG is well established, and the Los Angeles County Sanitation District has successfully converted landfill gas to CNG since 1994 at its Clean Fuels facility. Several plants throughout the world, including one in California, upgrade biogas and inject it into natural gas pipelines. The conversion of landfill gas to LNG is much less prevalent, but facilities do exist. A plant in Rosenberg, TX produces 8,500 gallons per day, and there are two commercial scale demonstration projects in California. Anaerobic digestion technology to produce biogas is well developed worldwide. The biogas generated is mainly used to generate electricity, as well as to power onsite engines converted to run on biogas. In general, is not</td>
</tr>
</tbody>
</table>
well utilized beyond the production facilities.

**Vehicles.** Biogas, once treated and compressed or liquefied, can be used in the same vehicles that use fossil CNG or LNG. (See fuel assessments for CNG and LNG for details). Compressed natural gas vehicle technology is fully commercialized for both light and heavy-duty applications, and natural gas vehicles are widely available for purchase in most regions of the world. (See compressed natural gas fuel assessment on page 52 for details.) Liquefied natural gas vehicle technology is fully commercialized for heavy-duty applications. (See liquefied natural gas fuel assessment on page 58 for details.)

### Current production in Oregon

**Landfill gas**[^123]:
- Four projects with a combined capacity of 18.4 megawatts capture landfill gas and use it to produce electricity: Short Mountain, Coffin Butte, Dry Creek, and Columbia Ridge landfills.
- The Findley Butte landfill in Boardman captures biogas for co-generation of electricity, and has a capacity of 3.2 megawatts.
- St. Johns landfill pipes captured landfill gas to a nearby industrial facility.
- There are three facilities in development at Riverbend, Arlington, and Hillsboro landfills

**Wastewater treatment plants:**
Anaerobic digesters are part of the sewage treatment process at 28 large wastewater treatment plants in Oregon. The digester gas produced at these facilities in 2004 had an energy value of about 0.8 trillion Btu.[^124]

Twenty-eight wastewater treatment plants in Oregon use digester gas on site as boiler fuel to produce heat for the anaerobic digestion process and for space heating. The digester gas produced at these facilities in 2004 had an energy value of about 0.8 trillion Btu. Nine wastewater treatment plants use digester gas as fuel to generate electricity. These include Tri-City Service District, Clackamas County Service District, Clean Water Services, City of Portland, City of Gresham, City of Salem, City of Medford, and Eugene Public Works. These plants generated about 26 million kilowatt-hours in 2004.[^125]

**Agricultural waste:** Several facilities produce biogas from agricultural waste. These include Cal-Gon Dairy, Port of Tillamook, and Stahlbush Island


There are also several biogas production facilities in development, such as Rickreall Dairy, Ferrera Farms, Lochmead Dairy, Three Mile Farms, and Neils Jenson Farms.

### Potential production in Oregon

Many facilities in Oregon produce biogas, however it’s production for use as a transportation fuel is limited. The following describes current Oregon production of biogas from all sources for all uses.

**Landfill Gas:** EPA considers a landfill to be a good candidate for generating biogas when it has at least one million tons of waste and is still operational or has been closed for five years or less. Most landfills that fit this description already use biogas, although not for transportation purposes. There are three candidate landfills in Oregon.\(^{126}\) These are the Knott landfill in Bend, Northern Wasco County landfill in The Dalles, and Roseburg landfill in Roseburg. Other landfills in Oregon might also be appropriate for a landfill gas project depending on the conditions at the site.

**Wastewater treatment plants:** The Department of Energy estimates that, overall, as much as 36 percent of the biogas produced at Oregon’s wastewater treatment facilities is unused. This surplus biogas is a potential source of transportation fuel. In 2004, the unused gas had an energy value of approximately 0.3 trillion Btu.\(^ {127}\)

**Agricultural waste:** EPA indicates that the potential for a positive financial return from producing biogas from livestock manure appears to be best at dairy operations with more than 500 cows and swine operations with more than 2,000 head.\(^ {128}\) In 2003, 111 dairies in the state were licensed for herds of 500 or more cows. Based on the cumulative number of cows on-site at these dairies, the Department of Energy estimates that approximately 3,400 million cubic feet of biogas is potentially available annually through anaerobic digestion technology. This amount of biogas would have an energy value of about 1.7 trillion Btu, which could produce up to 13 average megawatts of electricity.\(^ {129}\)

### Landfill gas

According to the Energy Information Administration, production of landfill gas in the United States has increased from 2006 to 2007 from 150 to 173 trillion BTUs.\(^ {130}\) Several studies indicate that there is a large potential for production of biogas throughout the United States. Natural

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Gas Vehicles for America cites a 1998 study estimating that the biogas potential from landfills, animal waste, and sewage is equivalent to 6% of U.S. natural gas consumption or 10 billion gasoline gallon equivalents of transportation fuel (about 7% of year 2006 U.S. gasoline consumption).\(^{131}\)

**Wastewater treatment plants:** According to the EPA, there remains a great deal of potential for biogas production and use from wastewater treatment plants throughout the United States.\(^{132}\)

**Agricultural waste:** In 2009, there were 140 anaerobic digester systems operating at commercial livestock farms the United States. These projects generate approximately 378,500 MWh annually through electricity production, boiler projects and pipeline injection.\(^{133}\)

<table>
<thead>
<tr>
<th>Current use in Oregon</th>
<th>Volume. It is unknown how much biogas is used as a transportation fuel in Oregon, but the volume is not large relative to other fuels.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Number of vehicles.</strong> Unknown.</td>
</tr>
<tr>
<td></td>
<td><strong>Existing fueling infrastructure.</strong> Unknown.</td>
</tr>
<tr>
<td></td>
<td><strong>Barriers to expansion.</strong> The volume of available feedstock and geography of pipeline supply and fleet fueling limit the potential for expansion of the use of biogas as a transportation fuel.</td>
</tr>
</tbody>
</table>

### Summary of known trends:

- **Volume produced.** Although this is not related directly to transportation use of biogas, in the United States, production of biogas produced from landfills increased over 15% percent from 2006 to 2007.

- **Volume used.** In a limited number of locations and countries, biogas has proven a useful transportation fuel and contributes substantially to the transportation mix in that area or country.\(^{134}\)

- **Number of vehicles.** Unknown.

### Preliminary Estimates of

<table>
<thead>
<tr>
<th>Future estimates</th>
</tr>
</thead>
</table>

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<table>
<thead>
<tr>
<th>2022 Use:</th>
<th>Forecast #1: As markets develop for low carbon fuels biogas could be used for transport due to its favorable low carbon emissions.</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Future use</td>
<td></td>
</tr>
<tr>
<td>• Low</td>
<td></td>
</tr>
<tr>
<td>• Moderate</td>
<td></td>
</tr>
<tr>
<td>• High</td>
<td></td>
</tr>
<tr>
<td>Forecast #2: Biogas can play a role in future transportation in Oregon, but not a large one due to feedstock restraints. However, due to its exceptionally low carbon intensity, a small amount of biogas fuel could generate credits.</td>
<td></td>
</tr>
<tr>
<td>Forecast #3: A low carbon fuel standard in Oregon could potentially spur more biogas production and use for transportation than would have happened otherwise. Trends in other countries or states that use large volumes of biogas for transportation could help us identify feasible production and use rates for both passenger and medium/heavy-duty applications.</td>
<td></td>
</tr>
<tr>
<td><strong>Low estimate (proposed for discussion)</strong></td>
<td></td>
</tr>
<tr>
<td>Zero. Based on very low current use of biogas for transportation in Oregon, DEQ proposes that no increased biogas use in Oregon would bracket the lower range of inputs for the LCFS compliance scenarios.</td>
<td></td>
</tr>
<tr>
<td><strong>Moderate estimate (proposed for discussion)</strong></td>
<td></td>
</tr>
<tr>
<td>1/2 of remaining unused biogas potential. DEQ proposes the high estimate for biogas used as a transportation fuel is based on ½ of the unused Oregon potential. DEQ proposes to calculate unused biogas potential based on:</td>
<td></td>
</tr>
<tr>
<td>• Landfills currently operating or closed less than 5 years with 1 million tons of waste that do not capture and use landfill gas.</td>
<td></td>
</tr>
<tr>
<td>• Dairy operations of 500 head or greater with no anaerobic digester</td>
<td></td>
</tr>
<tr>
<td>• Unused wastewater treatment plants</td>
<td></td>
</tr>
<tr>
<td><strong>High (but feasible) (proposed for discussion)</strong></td>
<td></td>
</tr>
<tr>
<td>3/4 of remaining unused biogas potential. DEQ proposes the high estimate for biogas used as a transportation fuel is based on ¾ of the unused Oregon potential.</td>
<td></td>
</tr>
</tbody>
</table>

Further reading:
## Butanol or Bio-Butanol

<table>
<thead>
<tr>
<th>Feedstock and production</th>
<th>Feedstock.</th>
<th>Biobutanol is butanol (a 4-carbon alcohol known as butyl alcohol) produced from biomass feedstocks. Currently, butanol’s primary use as an industrial solvent in products such as lacquers and enamels. Like ethanol, biobutanol is an alcohol that can be produced through processing of domestically grown crops, such as corn, wheat, sugar beets, sorghum, and cassava.(^{135}) Biobutanol can also be produced from a mixture of wood wastes, agricultural residues and manure. Production. Historically, biobutanol was manufactured from corn and molasses in a fermentation process known as an ABE (acetone, butanol, ethanol) fermentation. Biobutanol made from fermentation processes are more expensive than from petrochemical production processes. Currently, butanol is produced almost entirely from petroleum.(^{136}) Commercial biobutanol production has several limitations, including low values for final product concentration and degradation stemming from the toxicity of butanol to microbial organisms.(^{137}) Researchers are also working on developing more efficient production processes with greater output.(^{138, 139}) Biobutanol can also be produced from processes that gasify wood wastes, agricultural residues and manure into a syngas.(^{140}) This gasification process converts biomass into a synthesis gas that is cleaned, fed into a catalytic reactor and purified to generate biobutanol, ethanol and methanol.(^{141})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Co-products</td>
<td>The conventional microbial producer of (bio)butanol from agricultural feedstocks generates three products: acetone, butanol and ethanol, via ABE fermentation. Electricity can also be generated from the production method.(^{142})</td>
<td></td>
</tr>
</tbody>
</table>

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**Commercialization status**
- **Fuel**
- **Vehicles**

**Fuel.** The production of butanol is fully commercialized. The production of biobutanol is not fully commercialized at this time. California Air Resources Board staff indicate they do not think the fuel will be fully commercialized until sometime after 2020.¹⁴³ The fuel is still in the research and development phase, however, several pilot plants have been planned.¹⁴⁴

Gevo, Inc. retrofitted an existing demonstration scale ethanol plant to produce biobutanol in 2009. Successful production of biobutanol at the 1 million gallon per year pilot plant demonstrates the viability of this technology for retrofitting existing ethanol plants to make biobutanol.¹⁴⁵

**Vehicles.** According to the U.S. DOE Alternative Fuels and Advanced Vehicles Data Center, biobutanol is compatible with the current gasoline distribution infrastructure and would not require new or modified pipelines, blending facilities, storage tanks or retail station pumps to produce and distribute.¹⁴⁶

Under U.S. Environmental Protection Agency regulations, biobutanol can be blended as an oxygenate with gasoline in concentrations up to 11.5 percent by volume. Biobutanol can also improve the blending of ethanol with gasoline.¹⁴⁷ Results showed that butanol mixed with diesel can reduce emissions of criteria pollutants.¹⁴⁸

**Current production in Oregon**

Oregon-based Diesel Brewing has launched an initiative to manufacture cellulosic biobutanol from biomass and dairy farm manure.

Diesel Brewing is beginning with a demonstration facility to be built in Salem, Oregon by the end of 2009, which will process one ton per day of biomass.¹⁴⁹ The company plans to construct a 10-ton unit with a start-up date of October 2010 in Boardman, Oregon to demonstrate production yields, fuel ratios, and gas cleanup procedures, and will allow the company to further fine tune and balance the processes. Diesel Brewing plans to build a

http://www.rsc.org/chemistryworld/Issues/2008/February/BiobutanolEntersBattleAlcohols.asp
commercial-scale plant of at least 100 dry tons-a-day, again in Boardman, with a projected start-up of October 2012. The company anticipates building more refineries across Oregon after successful completion of the pilot and demonstration phases.

### Potential production in Oregon

See the Oregon Biomass Assessment report prepared for the April 15, 2010 Advisory Committee meeting for information on Oregon’s potential for producing biomass. [http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm](http://www.deq.state.or.us/aq/committees/advcomLowCarbonFuel.htm)

### Out-of-state production

Currently, biobutanol is not produced on a commercial scale.

### Current use in Oregon

- **Volume**
- **Number of vehicles**
- **Existing fueling infrastructure**
- **Barriers to expansion**
- **Special issues**

#### Volume
None.

#### Number of vehicles
Not applicable.

#### Existing fueling infrastructure
The infrastructure needed for widespread commercial availability of biobutanol, such as processing plants and pipelines for transport, are already available and being used for fossil fuels and gas.

#### Barriers to expansion
Problems associated with using agricultural feedstocks as fuel could affect the viability of biobutanol from such sources.

To date, biobutanol has been relatively expensive to produce. Production of butanol from corn and other biomass has been stymied by the lack of technology to make it economically viable. The problem has been historically low yields and low concentrations of biobutanol compared to those of bioethanol. Until now, the technology and economics did not exist to pursue butanol over ethanol as a viable alternative to gasoline.

### Summary of known trends:

- **Volume produced**
- **Volume used**
- **Number of vehicles**

#### Trend: volume used
None in Oregon.

#### Trend: volume produced
None in Oregon.

#### Trend: number of vehicles
Not applicable.

---


<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Future use</td>
<td><strong>Low estimate (proposed for discussion)</strong></td>
</tr>
<tr>
<td>• Low</td>
<td>It is possible, due to lack of infrastructure and historic use, that no biobutanol will be used for transportation purposes in Oregon. In the event that biobutanol is used in Oregon for transportation, a carbon intensity for biobutanol would be calculated and the fuel would be treated as any other biofuel under the low carbon fuel standard.</td>
</tr>
<tr>
<td>• High</td>
<td><strong>Moderate estimate (proposed for discussion)</strong></td>
</tr>
<tr>
<td></td>
<td>Based on the proposed biobutanol demonstration plant in Oregon, it is feasible a larger facility could be built in Oregon, and that <strong>10 to 25 million gallons</strong> will be available in 2022.</td>
</tr>
<tr>
<td></td>
<td><strong>High (but feasible) estimate (proposed for discussion)</strong></td>
</tr>
<tr>
<td></td>
<td>Based on the size of one or two commercial plants, it is feasible that <strong>25 to 75 million gallons</strong> will be available in 2022.</td>
</tr>
</tbody>
</table>
**Hydrogen Fuels**

**Feedstock and production process**

**Feedstock.** A hydrogen vehicle is an alternative fuel vehicle that uses hydrogen as its onboard fuel for motive power. The power plants of such vehicles convert the chemical energy of hydrogen to mechanical energy either by burning hydrogen in an internal combustion engine, or by reacting hydrogen with oxygen in a fuel cell to run electric motors. Widespread use of hydrogen for fueling transportation is a key element of a proposed hydrogen economy.

The ability to create hydrogen fuel from a variety of resources and its clean-burning properties make it a desirable alternative fuel. However, it can be produced from a wide range of sources (such as wind, solar, or nuclear) that are intermittent, too diffuse or too cumbersome to directly propel vehicles. Integrated wind-to-hydrogen plants, using electrolysis of water, are exploring technologies to deliver costs low enough, and quantities great enough, to compete with traditional energy sources.

Pure hydrogen and hydrogen mixed with natural gas (hydrogen) have been used effectively to power automobiles with internal combustion engines.

**Production process.** The predominant method for producing hydrogen gas is steam reforming of natural gas. Methanol, coal or biomass can also be used to make hydrogen. The U.S. Department of Energy\(^{155}\) and other market developers see hydrogen infrastructure based on natural gas steam reformation at the service station, opposed to vehicles powered by hydrogen reformed onboard the vehicle.

A hydrogen internal combustion engine vehicle is a type of hydrogen vehicle using an internal combustion engine. Hydrogen internal combustion engine vehicles are different from hydrogen fuel cell vehicles; the engine is simply a modified version of the traditional gasoline-powered internal combustion engine.

Hydrogen also has potential as fuel for fuel cell vehicles. Hydrogen and oxygen fed into a proton exchange membrane fuel cell "stack" produce enough electricity to power an electric automobile, without producing any harmful emissions from the vehicle.

Many companies are working to develop technologies that might efficiently exploit the potential of hydrogen energy for mobile uses. The attraction of using hydrogen as an energy currency is that hydrogen prepared without using fossil fuel inputs has no carbon dioxide emissions.

<table>
<thead>
<tr>
<th>Co-products</th>
<th>None</th>
</tr>
</thead>
</table>

**Commercialization Status**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Vehicles</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fuel</strong></td>
<td>Although fueling stations exist in many states and other countries, researchers continue to work on increase efficiency and yield in hydrogen production processes and storage.¹⁵⁶</td>
</tr>
<tr>
<td><strong>Vehicles</strong></td>
<td>Hydrogen vehicles are not fully commercialized</td>
</tr>
<tr>
<td></td>
<td>• Hydrogen internal combustion engine vehicles are not yet commercialized.¹⁵⁷</td>
</tr>
<tr>
<td></td>
<td>• Hydrogen fuel cell vehicles are not yet commercialized. In 2009, seven automakers committed to commercializing hydrogen vehicles by 2015.¹⁵⁸,¹⁵⁹</td>
</tr>
</tbody>
</table>

**Current Production in Oregon**

| Hydrogen fuel is not available commercially in Oregon. |

**Potential Production in Oregon**

| Production prospects in Oregon are highly dependent upon significant infrastructure investments and market demand for the hydrogen fuel. |

**Out-of-state Production**

| The California Hydrogen Highway is an initiative by the California Governor to implement a series of hydrogen refueling stations along that state. As of July 2007 California had 179 fuel cell vehicles and twenty-five stations were in operation. However, there have already been three hydrogen-fueling stations decommissioned.¹⁶⁰ |

**Current Use in Oregon**

| **Volume** | None. |
| **Number of vehicles** | None in Oregon.¹⁶¹ |
| **Existing fueling infrastructure** | None in Oregon.¹⁶¹ |
| **Barriers to expansion** | None in Oregon.¹⁶² |

¹⁶⁰ California Fuel Cell Partnership. [http://www.cafcp.org](http://www.cafcp.org)
¹⁶² Joseph J. Romm PhD. The hype about hydrogen: fact and fiction in the race to save the climate.
### Barriers to expansion
- Current fuel cell car costs $400,000 - $1,000,000 (million). Most hydrogen cars are only available in demonstration models. The estimated number of hydrogen-powered cars in the United States was 200 as of October 2009, mostly in California.
- Not enough room onboard for hydrogen fuel to give the driving range consumers want.
- Hydrogen fuel is 2x to 3x the price of gasoline.
- Need fueling infrastructure.
- Hydrogen could have a difficult time competing with other advancing technologies.
- Ford Motor Company has dropped its plans to develop hydrogen cars, stating that "The next major step in Ford’s plan is to increase over time the volume of electrified vehicles".  

### Special issues

<table>
<thead>
<tr>
<th>Summary of known trends:</th>
<th>Trend: volume used.</th>
<th>Trend: volume used. From 2003 to 2007, hydrogen use in the United States increased from 2,000 to 66,000 gallons of gasoline equivalent, an average increase of 55% per year.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Other countries and states see great promise in hydrogen, and are investing in vehicles and fueling infrastructure.</td>
</tr>
<tr>
<td></td>
<td>Trend: volume produced.</td>
<td>Trend: volume produced. In the U.S. and worldwide, the number of fueling stations continues to grow.</td>
</tr>
<tr>
<td></td>
<td>Trend: number of vehicles.</td>
<td>Trend: number of vehicles. The number of hydrogen vehicles in use has increased from 9 in 2003 to 223 in 2007.</td>
</tr>
</tbody>
</table>

### Preliminary Estimates of 2022 Use:
- **Future use**
- **Low**
- **High**

### Future use estimates
- **Forecast #1**: Several states in the US, as well as other countries, see great promise in hydrogen, and have been investing in vehicles and fueling stations.

---

Forecast #2: The Energy Information Administration predicts that starting in 2016, the U.S. will start to see a dramatic increase in the use of hydrogen, from 0.8 to 11.4 million gallons of gasoline equivalent. They predict all of this will be in light-duty vehicles use.169

Low estimate (proposed for discussion)

Zero. Based on the commercialization status of fuels and vehicles, and the lack of infrastructure in Oregon, DEQ concludes that it is possible no hydrogen will be used in Oregon by 2022.

High (but feasible) estimate (proposed for discussion)

Zero. Based on the historic use and lack of fueling infrastructure, DEQ proposes not to include any hydrogen in the compliance scenarios for the low carbon fuel standard.

In the event that hydrogen is used in Oregon for transportation, hydrogen would be assigned a carbon intensity and could participate in the low carbon fuel standard as any other fuel would. In addition, the rules will address hydrogen, as we have discussed in past advisory committee meetings.

Further reading:


California Fuel Cell Partnership website: [http://www.cafcp.org/home](http://www.cafcp.org/home)

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## Biofuels from Algae

**Feedstock and production**

**Feedstock.** Typically, oils from microalgae are the feedstock for biodiesel production.\(^{170}\)

**Production.** Algae uses energy from sunlight to produce simple sugars, converts them into oils or complex carbohydrates and stores both substances in its cells. Potential fuels from algae include biodiesel, ethanol, Fischer Tropsch rules, hydrogen, alkanes, and methane.\(^{171}\)

While years of research have gone into studying the use of microalgae as a source for producing hydrogen, no commercial-scale process has been demonstrated to date.\(^{172}\) Several companies are currently conducting pilot projects to further research the production of biofuels from algae.\(^{173}\)

Current research and development efforts in the United States have largely focused on microalgae as a source of oils. Several species produce high oil yields that greatly outweigh yields from conventional crops. The oil from algae could be refined into gasoline range hydrocarbons. Existing process equipment may be able to be used for this purpose.\(^{174}\)

**Co-products**

Cultivation of algae in conjunction of wastewater treatment (with CO\(_2\) addition from combustion emissions) has the potential of fixing CO\(_2\), removing soluble nitrogen and phosphorous in the wastewater, and producing O\(_2\), in addition to generating biomass for biofuel feedstock. Biomass by-products from the oil extraction process may also have potential uses in cattle feed, cosmetics, vitamins and pigments.\(^{175}\)

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| **Commercialization status** | **Fuel.** Producing biofuels from algae is not commercialized. There are very few pilot or demonstration scale facilities in the United States. Technology to mass-produce algae and extract its oils could be five to ten years in the future. Research continues in this regard, and the technology is anticipated to be commercially viable sometime after 2020.  
**Vehicles.** A San Diego, CA company claims to have made a renewable fuel using modified algae that meets fuel quality standards for use as an alternative to gasoline. However, this technology is still under development and is not expected to be commercially viable before 2011. |
|---|---|
| **Current production in Oregon** | Oregon State University researchers are working to find an efficient method of processing algae to produce biodiesel fuel and ethanol. Two small experimental photobioreactors to grow microscopic algae in a closed system have been built at OSU’s Sustainable Technologies Laboratory in Corvallis.  
WW Moss has proposed a 100-acre algal biofuels facility for the Port of Umatilla. The company said it would produce biodiesel, omega-3 fatty acids for the nutraceutical market and animal protein supplements. |
| **Potential production in Oregon** | Unknown at this time. |
| **Out-of-state production** | Unknown at this time. |
| **Current use in Oregon** | **Volume.** There is no production of biofuels from algae in Oregon.  
**Number of vehicles.** Not applicable. |

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http://www.greencarcongress.com/2008/05/sapphire-energy.html


<table>
<thead>
<tr>
<th>Existing fueling infrastructure</th>
<th>Existing fueling infrastructure. Not applicable.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barriers to expansion.</td>
<td>Barriers to expansion. Not commercialized, and it is in the research and development phase.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Summary of known trends:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume produced</td>
</tr>
<tr>
<td>Volume used</td>
</tr>
<tr>
<td>Number of vehicles</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Trend: volume used.</th>
</tr>
</thead>
<tbody>
<tr>
<td>None in Oregon.</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Trend: volume produced.</th>
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<tbody>
<tr>
<td>None in Oregon.</td>
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<thead>
<tr>
<th>Trend: number of vehicles.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Not applicable.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Preliminary Estimates of 2022 Use:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
</tr>
<tr>
<td>High</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Low estimate (proposed for discussion)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zero. Based on the commercialization status and California Air Resources Board’s assessment of the potential for biofuels from algae, it is possible that no biofuels produced from algae will be produced before 2022.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>High (but feasible) estimate (proposed for discussion)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zero. Based on the commercialization status and California Air Resources Board’s assessment of the potential for biofuels from algae, DEQ proposes not to include any biofuels from algae in the compliance scenarios for the low carbon fuel standard.</td>
</tr>
</tbody>
</table>

In the event that biofuels from algae are used in Oregon for transportation, they would be assigned a carbon intensity and could participate in the low carbon fuel standard as any other biofuel would.

Further Reading:
Federal Renewable Fuel Standard 2 (RFS2)

The Environmental Protection Agency, under the Energy Independence and Security Act, will require that renewable fuel be blended into petroleum from 9 billion gallons in 2008 to 36 billion gallons by 2022.\(^{181}\) This is known as the federal Renewable Fuel Standard 2, or RFS2 for short. The federal program is a volumetric program which means the fuel distributors could sell high blends in one region and zero or low blends in another region and still meet the program's requirement. The program is primarily designed to significantly increase the volume of renewable fuel that is blended into gasoline.

There are several different categories of required renewable fuel.

In 2022, the following will be required in the United States:

- **16 billion gallons of cellulosic biofuels.** To qualify, a cellulosic biofuel would need to have a carbon intensity at least 60% less than the carbon intensity of conventional fuel (as determined by EPA). The following are considered cellulosic biofuels:
  - Cellulosic ethanol
  - Synthetic gasoline, synthetic diesel fuel or heating oil
  - Synthetic jet fuel, propane and biogas
  - Cellulosic diesel, such as Fischer-Tropsch diesel produced from biomass or other lignocellulosic to diesel production process

- **1 billion gallons of biomass-based diesel.** To qualify, a biomass-based diesel would need to have a carbon intensity at least 50% less than the carbon intensity of conventional fuel (as determined by EPA). The following are considered biomass-based diesel:
  - Biodiesel (FAME)
  - Non-Co-processed Renewable Diesel (renewable diesel that has not been co-processed with a petroleum feedstock)
  - Cellulosic diesel

- **4 billion gallons of unspecified “Other advanced biofuel.”** To qualify, an advanced biofuel would need to have a carbon intensity at least 50% less than the carbon intensity of conventional fuel (as determined by EPA). This could be anything listed above, plus butanol, biogas, Brazilian sugarcane ethanol, or any other type of fuel that meets the EPA requirements.

Oregon’s proportional share of these fuels

In 2007, Oregon consumption of gasoline and diesel represented approximately 1.18% of the total gasoline and diesel consumption in the United States.\(^{182}\)

\(^{181}\)US EPA. EPA Proposes New Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond. [http://www.epa.gov/oms/renewablefuels/420f09023.htm#3](http://www.epa.gov/oms/renewablefuels/420f09023.htm#3)

Oregon proportional share of these required federal Renewable Fuel Standard 2 fuels in 2022:

- Cellulosic biofuels: 188 million gallons
- Biomass-based diesel: 11.8 million gallons
- Other advanced: 46 million gallons

EPA, as outlined in Chapter 1.2 the Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, covers the following information:

**Chapter 1: Renewable Fuel Production and Consumption**
This chapter describes the various feedstocks and renewable fuel types that could potentially be used to meet the renewable fuel volumes required by EISA. The availability and challenges of harvesting, storing, and transporting these feedstocks are discussed, as well as the different renewable fuel production technologies, industry plans, and potential growth projections for future facilities. A discussion of renewable fuel distribution and consumption is included.

EPA recognizes that the required volumes could be met with a wide variety of fuel choices, and has developed a projected set of reasonable fuel volumes based on their best estimate of likely fuels that would come to market. They have projected a primary control case, and then two sensitivity control cases (high and low cellulosic ethanol).

---

### List of Biofuel Categories, the Fuels Produced and the Companies Pursuing the Technologies

Table Source: EPA’s Renewable Fuel Standard Program (RFS2) Final Regulatory Impact Analysis. Table 1.4-1, page 115.\(^\text{184}\)

<table>
<thead>
<tr>
<th>Technology Category</th>
<th>Fuels Produced</th>
<th>Companies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biochemical from Corn Grain</td>
<td>Ethanol</td>
<td>ICM, Delta T, Broin</td>
</tr>
<tr>
<td>Thermochemical/Biochemical conversion of Cellulose</td>
<td>Ethanol</td>
<td>Coskata and INEOS Bio.</td>
</tr>
<tr>
<td>Strong Acid Hydrolysis of Cellulose/Biochemical</td>
<td>Ethanol</td>
<td>Blue Fire, Arkenol, Pencor, Pangen, Auburn Univ., Agresti.</td>
</tr>
<tr>
<td>Dilute Acid, Steam Explosion of Cellulose/Biochemical</td>
<td>Ethanol</td>
<td>Verenium, BP, Central Minnesota Ethanol Coop.</td>
</tr>
<tr>
<td>Consolidated Bioprocessing (one step hydrolysis and fermentation) of Cellulose/Biochemical</td>
<td>Ethanol</td>
<td>Mascoma</td>
</tr>
<tr>
<td>Biochemical conversion of Cellulose via carboxylic acid</td>
<td>Ethanol, Gasoline, Jet Fuel, Diesel Fuel</td>
<td>Terrabon, Swift Fuels, Zeachem</td>
</tr>
<tr>
<td>Thermochemical/Fischer Tropsch</td>
<td>Diesel Fuel and Naphtha</td>
<td>Choren, Flambeau River Biofuels, Baard, Clearfuels, Gulf Coast Energy, Rentech, TRI.</td>
</tr>
<tr>
<td>Thermochemical/Fischer Tropsch</td>
<td>DME</td>
<td>Chemrec, New Page.</td>
</tr>
<tr>
<td>Catalytic Depolymerization of Cellulose</td>
<td>Diesel, Jet Fuel or Naphtha</td>
<td>Cello Energy</td>
</tr>
<tr>
<td>Biochemical conversion of Cellulose</td>
<td>Diesel, Jet Fuel or Naphtha</td>
<td>Bell Bioenergy</td>
</tr>
<tr>
<td>Catalytic Reforming of Sugars</td>
<td>Gasoline</td>
<td>Virent</td>
</tr>
<tr>
<td>Biochemical conversion of Sugars</td>
<td>Diesel, Jet Fuel or Gasoline</td>
<td>Amyris, Gevo, LS9.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Process</th>
<th>Product</th>
<th>Companies/Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biochemical of Sugars – converted corn ethanol plants</td>
<td>Isobutanol</td>
<td>Gevo/ICM.</td>
</tr>
<tr>
<td>Pyrolysis of Cellulose</td>
<td>Diesel, Jet Fuel, or Gasoline</td>
<td>Envergent (UOP/Ensyn), Dynamotive, Petrobras, Univ. of Mass, KIOR.</td>
</tr>
<tr>
<td>Hydrotreating of Plant Oils</td>
<td>Renewable Diesel Fuel</td>
<td>UOP, Neste, Eni, Conoco-Phillips, Dynamic Fuels (Syntroleum/Tyson).</td>
</tr>
<tr>
<td>Fatty Acid Methyl Ester (FAME)</td>
<td>Biodiesel</td>
<td>Many</td>
</tr>
<tr>
<td>Free Fatty Acid to Biodiesel</td>
<td>Biodiesel</td>
<td>Endicott</td>
</tr>
<tr>
<td>Production of Algae Oils via Photobioreactor or open pond</td>
<td>Algae Oil (Biodiesel or Renewable Diesel Fuel)</td>
<td>Solazyme, Algenol, Aurora Biofuels, Petrosun, Sapphire Energy, Livefuels, Solix, HR Biopetroleum (Cellana), XL Renewables, Petroalgae, Synthetic Genomics, GreenFuel.</td>
</tr>
</tbody>
</table>
The purpose of this biomass assessment is to summarize available studies and information on the quantity of biomass feedstocks that may be available annually in Oregon for production of advanced biofuels. Links to each of these studies can be found in the Appendix on page 13.

The main question this document will address is does Oregon currently have available biomass feedstock, or the potential to produce such feedstock, for advanced biofuels? The document describes:

1. Different types of biomass potentially available in Oregon (see page 3);
2. Types of fuel that can be produced from each biomass source (see page 6);
3. Issues related to using biomass for transportation fuel production (see page 7);
4. A summary of conclusions from biomass studies in Oregon (see page 9);
5. Existing biofuels crops: (see page 11); and
6. Potential biofuels crops. (see page 11).

Summary

Oregon has limited ability to produce feedstock for corn ethanol and soy biodiesel, but could have much more feedstock available for production of cellulosic ethanol, cellulosic diesel, and fuel from waste such as yellow grease. Oregon also has the ability to produce feedstocks for biodiesel and renewable diesel, and to produce biogas, but to a lesser extent. (See section 2 starting on page 6 for a discussion of each fuel type and its associated forms of biomass.)

Based upon estimates from biomass inventory and assessment studies conducted during the past decade, a range of 424 to 524 million gallons of gasoline equivalent of biofuel and other alternative transportation fuel a year could be produced from Oregon biomass. This represents approximately 20% to 24.6% of Oregon’s consumption of gasoline and diesel (2.172 billion gallons as of 2008). Both low and high projections are provided because many of the studies estimated a range of available biomass for forest and agricultural residue, as well as urban wood waste, dependent on price for collection and transport of the materials. Because these sources are dispersed, more of the available material can be collected if a higher price is paid. See the Appendix on page 13 for more information and links to each of the studies.

If only waste sources of biomass were used, and no crops, 182 to 282 million gallons of gasoline equivalent biofuels and compressed natural gas could be made from biomass waste in Oregon. This
represents approximately 8% to 13% of Oregon’s current consumption of gasoline and diesel. The variance in the analysis is due to a range of prices that could be paid for waste material utilized.

Several energy production facilities are also looking at using biomass. Also note that the studies to date have not covered several of Oregon’s potential sources of biomass. In addition to several sources of biomass for cellulosic fuel, very few of the feedstocks for producing biodiesel have been quantified. In addition to biomass, some fuel production technologies are under development that would produce fuel from waste such as tires or plastic. This study does not cover those feedstocks.

The variance in the low and high estimates for the first three categories in Table 1 below (forest residue, agricultural residue and urban wood waste) comes from analysis of the cost to collect and transport the material. At lower prices, less material can be collected, while at higher prices, more of the material can be collected. See the Appendix (page 13) or the studies for more details.

Table 1: Potential range of low carbon fuel production from available Oregon biomass

<table>
<thead>
<tr>
<th>Source</th>
<th>Potential fuel volume produced (Millions of gallons of gasoline equivalent/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fuel from Waste</strong></td>
<td></td>
</tr>
<tr>
<td>1. Forest residue</td>
<td>58 to 132 (dependent on price paid)</td>
</tr>
<tr>
<td>2. Agricultural residue (corn and wheat only)</td>
<td>13 to 32 (dependent on price paid)</td>
</tr>
<tr>
<td>3. Urban wood waste</td>
<td>11 to 19 (dependent on price paid)</td>
</tr>
<tr>
<td>4. Unused mill residues</td>
<td>1</td>
</tr>
<tr>
<td>5. Orchard and vineyard prunings</td>
<td>6</td>
</tr>
<tr>
<td>6. Grass straw residue</td>
<td>33</td>
</tr>
<tr>
<td>7. Greenwaste</td>
<td>18</td>
</tr>
<tr>
<td>8. Mixed Waste Paper</td>
<td>41</td>
</tr>
<tr>
<td>9. Biogas</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Fuel from Waste</strong></td>
<td>182 to 282</td>
</tr>
<tr>
<td><strong>Fuel from Crops</strong></td>
<td></td>
</tr>
<tr>
<td>Expanding Conservation Reserve Program</td>
<td>239</td>
</tr>
<tr>
<td>Program planted to a dedicated energy crop</td>
<td></td>
</tr>
<tr>
<td>Existing crops</td>
<td>13</td>
</tr>
<tr>
<td><strong>Total Fuel from Crops</strong></td>
<td>242</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>424 to 524</td>
</tr>
</tbody>
</table>

1 The amount of fuel produced from biogas is 0.023 million gallons of gasoline equivalent per year.
This summary relies on several existing sources of information, summarized in Appendix A (page 13). There are several sources of potential biomass feedstock from waste that are not included in this estimate, because no recent studies have quantified volumes available.

**Figure 1: Lower estimates of biomass availability compared with gasoline and diesel use in Oregon**

![Figure 1](image1)

**Figure 2: Higher estimates of biomass availability and alternative fuel production compared with gasoline and diesel use in Oregon**

![Figure 2](image2)

There is ongoing biomass work occurring in Oregon. As a result of these efforts, more and better information will be available in the future. Efforts include:
• Oregon Department of Agriculture, Oregon Department of Energy and Oregon Department of Forestry are collaborating on this issue.
• A forthcoming study will address the potential for bioenergy production from grass straw in Lane County.
• Oregon State University is working on quantifying available agricultural residue.
• Washington State University’s Climate Friendly Farming Program is also investigating agricultural residue potential.

1. Types of biomass potentially available in Oregon

Oregon defines biomass as any organic matter, including woody biomass, agricultural crops, wood wastes and residues, plants, aquatic plants, grasses, residues, fibers, animal wastes, municipal wastes and other waste materials.

The following describes sources of different types of biomass:

A. Wood

There are several types of woody biomass.

1. Forest-derived biomass: This category includes several types of biomass, such as thinning of timberland with high fire hazard, logging residue (the tree tops, limbs and cull material leftover from commercial logging activity), and thinning of timberland for commercial harvest preparation or other purposes.

2. Urban wood waste: This category includes wood discarded from individual houses, commercial businesses and construction and demolition sites, such as lumber, pallets, crates, wood furniture, tree and brush pruning’s, limbs, trunks and stumps.

3. Hybrid poplar plantations: Whole trees can be used as a source of biomass, or when hybrid poplars are harvested for other purposes, such as pulp chips, the leftover bark, leaves and stumps can be used for fuel.

4. Mill waste/residue: During the milling process, waste such as bark, chunks, slabs, shavings and sawdust are produced.

B. Municipal Solid Waste

This category can include several different sources of biomass, including food waste, waste paper, yellow grease, brown grease, food processing waste and cardboard.

C. Biogas

Biological degradation of organic material such as wastewater, manure and organic material in landfills produces biogas, which can be upgraded and used as a transportation fuel in the form of
compressed natural gas or liquefied natural gas, or used to produce electricity. There are three main sources of biogas:

1. **Wastewater Treatment**: Several wastewater treatment plants are producing biogas, through anaerobic digestion, however it is rarely used for a transportation fuel in Oregon.

2. **Organic Waste Digesters**: Manure from livestock on Oregon farms is a resource for the production of biogas through anaerobic digestion technology. Other organic wastes, such as agricultural and food-processing wastes, also could be used as digester feedstock.

3. **Landfills**: Anaerobic digestion of organic materials in landfills produces landfill gas, which can be captured and used.

**D. Agricultural Sources**

1. **Agricultural Residue**: There are several sources of agricultural residue. Agricultural crop residues are residues left on a field after the harvest of a crop. The harvest of grass seed and field crops such as corn and wheat generates a residue of straw, stalks and stubble. In addition, orchard pruning and processing of various agricultural crops such as mint and fruits and vegetables produces residues.

2. **Existing biofuels crops**: Some crops that can be used for fuel production are already grown in Oregon in limited quantities. The limited quantities could, however be used for fuel production. Crops that are produced in Oregon suitable for fuel production include:
   a. Corn
   b. Canola
   c. Camelina
   d. Hybrid poplar
   e. Sugar beets

3. **Potential biofuels crops**: Several biofuels crops could be grown in Oregon, in addition to the list above. Washington State’s low carbon fuel standard program has identified five potential biofuels crops, which can be grown in the Pacific Northwest (Pont, 2009). The amount of biomass that can be produced from these crops is influenced by the areas of Oregon where they can be grown, whether they would be grown as perennial or rotational crops, and the market for the product. These crops include:
   - **Hybrid poplars**. Hybrid poplar is a perennial crop that is successfully grown in western Oregon and irrigated regions of eastern Oregon.
   - **Switchgrass and miscanthus**. Researchers are currently developing varieties of these perennial grasses, which can be grown on irrigated cropland in the Columbia Basin.
   - **Brassica juncea**. Brassica juncea includes several varieties of yellow and brown mustards that are grown for oil, as a condiment, and for greens.
- **Camelina.** Camelina is an oilseed crop that can tolerate a range of growing conditions. It requires relatively low inputs and also has relatively low yields compared to some other oilseed crops. Sales of oilseed meal for livestock feed are usually an important contributor to the economic viability of oilseed crops, but currently only limited levels of camelina are allowed to be blended into livestock feed. More data are necessary before camelina can be fed at higher levels and to other types of livestock.

Several agricultural producers and researchers in the Willamette Valley and Malheur County are also trying soybeans as an alternative crop for irrigated agricultural land. Cold tolerance issues have prevented growers from successfully raising soybean crops in the past, but researchers in the public and private sector have helped develop some cold-tolerant varieties.

There are also sources of biomass that have not been fully quantified for Oregon. Washington completed a biomass inventory (Frear, 2005) that covered 45 potential sources of biomass in Washington. Potential sources for which quantities have not been evaluated in Oregon include things such as barley straw, mint slug, horse manure, culled fruits and vegetables, yellow grease (restaurant grease), brown grease (sewer and pipe grease that are trapped and collected), food processing waste, and cheese whey.

2. **Type of fuel that can be produced from each biomass source**

A variety of conversion technologies can be used to produce fuel or energy from biomass. A number of these technologies are currently used in Oregon to provide space and process heat, generate electricity, or produce liquid and solid fuels.

The Oregon Department of Energy recently conducted a survey of bioenergy producers and found that biomass feedstocks are being utilized throughout the state.

- Over 3 million tons of woody biomass was used in 2007 to produce steam and electricity.
- Anaerobic digesters and landfill gas capture systems were installed at over 30 locations in the state.
- Over 1 million tons of residual wood waste and chips are used to produce wood pellets and briquettes
- Used oil and waste grease is being collected and processed into biodiesel by at least three firms.

Oregon entrepreneurs, researchers, and companies are also experimenting with other conversion technologies. For example, there are currently efforts underway to develop, test, and commercialize pyrolysis, torrefaction, and gasification of woody biomass and agricultural wastes.

The feedstocks listed in Section 1 can produce several different types of fuel.

Ethanol can be made from:

- Starches such as corn, sugarcane, sugar beets or sorghum
- Cellulose such as poplar or willow, switchgrass, miscanthus
• Agricultural waste such as corn stover, or wheat, grass or barley straw
• Wood waste such as logging residue, mill residue, land clearing or forest thinning
• Municipal solid waste such as yard debris, paper waste, or food waste

Biodistillates such as renewable, synthetic or biodiesel can be made from:
• Oils such as soybeans, palm oil, canola, brassica, or camelina
• Municipal solid waste such as yellow grease

CNG and LNG can be made from:
• Food packaging waste such as culled fruits and vegetables, fruit pomace, cheese whey, animal waste
• Biowaste such as animal manure, brown grease, biosolids, landfill gas

Many of the above can also produce electricity or hydrogen. In addition, several technologies are under development to produce cellulosic diesel from biomass.

3. Issues related to using biomass for transportation fuel production

Highest and best use

The discussion of highest and best use for biomass feedstock is an active debate within many of the different resource areas. Recent federal programs, such as the Biomass Crop Assistance Program, have brought this debate to the fore and have provided more urgency for policy makers. While there is certain to be much debate on this topic in coming years, one thing is clear – this is a topic policy must take into consideration.

Much of the biomass that is considered a waste product, like sawdust or other mill residues, are low in price and are often the easiest biomass feedstock to access. As such, this waste stream has historically been utilized to a high degree in the production of other products (composite materials, particle/fiber board, animal bedding) or used to provide fuel for energy production (typically at a boiler to provide heat and power for the mill).

Ultimately, the markets for these feedstocks will determine how and where they are used. Some of the currently available biomass could be used in future waste-to-energy projects. It is useful, however, to consider that Oregon is poised to make investments in facilities that will increase the utilization of available biomass.
Sustainability

There are sustainability issues with using biomass for fuel production. Several of the studies cited considered sustainability and forest health, such as soil productivity, water quality, and wildlife habitat.

According to Oregon Department of Energy:

“Leaving some dead wood in the forest is good for forest ecosystems. Standing snags and dead wood on the forest floor provide habitat for wildlife. Woody debris on the ground deters erosion and, by its decomposition, helps maintain soil fertility and tilth. Although dead trees and woody debris play an important role in forest ecosystems, excessive accumulation of forest biomass becomes a threat to the health of live trees by making the forest susceptible to disease, insect infestations and high-intensity forest fires.

Reduced timber harvest activity and suppression of forest fires have caused an unnatural surplus of dead wood in many Oregon forests. Selective thinning in these areas could remove the excess biomass that poses a risk to sustainable forests.” (ODOE, 2010)

There are also concerns related to agricultural soil health and biomass removal. The primary consideration in agriculture is maintaining the productivity of the soil where crops are grown. After harvest, crop residue has a vital role to play in controlling erosion from wind and water, deterring runoff, maintaining or improving soil productivity, and maintaining nutrient levels. A percentage of crop residue left on the field helps maintain soil carbon and nutrients and improves soil tilth and porosity. For these reasons, only a percentage of agricultural residue is available as a biomass energy resource.

Carbon Intensity

Fuel generated from waste, such as forest residue, municipal solid waste, or agricultural residue will in general have lower carbon intensity than a fuel produced from a crop. This is because it is waste material, and the lifecycle analysis therefore does not include the production of the material, just the transport of the waste, conversion into fuel, distribution and use. For example, California Air Resources Board (CARB, 2009) found that the lifecycle greenhouse gas emissions for compressed natural gas from fossil sources are much higher than those for landfill gas (biomethane). Similarly, the lifecycle greenhouse gas emissions from biodiesel produced from soybeans is higher than biodiesel produced from used cooking oil.

Availability of biomass is dependent on price

Some biomass sources are dispersed over a wide area, such as agricultural or forest residue. Collection of biomass, particularly from sources that are widespread, can be costly compared to other sources that are already gathered in one location, such as mill residue. Estimates of forest-derived biomass found in the following studies often vary depending on the estimated cost of collection. Most of the studies looked at a range of costs per dry ton delivered or roadside ton delivered, and gave estimates of biomass produced based on collection costs. Some of the studies did not look at this factor, and this is noted in the summaries found in the Appendix on page 13. Some sources indicate that it may be difficult for fuel producers to ensure a steady supply of biomass from some sources of waste, for example, wastes.
associated with seasonal harvests. Wastes and residues might be used in conjunction with a cropped biomass supply, or with wastes or residues from a non-seasonal source. Or, a fuel producer might develop a steady, reliable source of waste or residue

4. Summary of conclusions from biomass studies in Oregon

None of the biomass studies in Oregon quantified all sources of biomass. Most focused on a limited number of biomass sources. Each study also used different assumptions, and some studies covered only a sub-region of the state. In general, most of the studies considered factors such as the amount of wheat straw or corn stover that would need to be left in the field for soil health, and the amount of forest residue needed to be left in the forest for forest health and wildlife habitat. Most of the studies estimated a total volume of biomass produced, and then subtracted out the amount that would need to be left in the forest or field for soil health, wildlife habitat, etc. They also generally subtracted out the biomass used for other purposes. For example, approximately 98 percent of mill residues are used for other purposes, so the numbers cited below are the unused amount. It is noted in the Appendix if this is the case for each study, and if a study took sustainability into consideration.

For each study referenced below, there is a link to the study itself so that if you can read further about the assumptions, methodology, sources of data, and the results. Each study is also summarized in the Appendix beginning on page 13.

Range of Potential Fuel Production from Available Biomass in Oregon (based on most recent study available for biomass source)

Each of the studies referenced in Tables 1 and 2 is summarized in the Appendix beginning on page 13. Also, please note that this summary of available biomass sources is not comprehensive, and that there are several potential sources of biomass in Oregon not included in these tables because they have not yet been inventoried.

The variance in the low and high estimates for the first three categories (forest residue, agricultural residue and urban wood waste) comes from analysis of the price to collect the material. At lower prices, less material can be collected, while at higher prices, more of the material can be collected. See the Appendix or the studies for more details.
Table 2: Potential Ethanol Production from Biomass Waste

<table>
<thead>
<tr>
<th>Biomass</th>
<th>Estimate of Quantity Available (Annual bone dry tons)</th>
<th>Conversion factor (gal/dry ton)</th>
<th>Ethanol production potential (Million gal/yr)</th>
<th>Millions of gallons of gasoline equivalent/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Forest residue</td>
<td>924,418$^2$ to 2,100,369$^2$</td>
<td>90.4$^3$</td>
<td>84 to 190</td>
<td>58 to 132</td>
</tr>
<tr>
<td>2. Agricultural residue (corn and wheat only)</td>
<td>194,272$^2$ to 481,825$^2$</td>
<td>95$^4$</td>
<td>18 to 46</td>
<td>13 to 32</td>
</tr>
<tr>
<td>3. Urban wood waste</td>
<td>182,532$^2$ to 304,220$^3$</td>
<td>90.4</td>
<td>17 to 28</td>
<td>11 to 19</td>
</tr>
<tr>
<td>4. Unused mill residues</td>
<td>16,320$^5$</td>
<td>90.4</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>5. Orchard and Vineyard Prunings</td>
<td>94,564$^2$</td>
<td>95</td>
<td>9</td>
<td>6</td>
</tr>
<tr>
<td>6. Grass straw residue</td>
<td>500,000$^7$</td>
<td>95</td>
<td>48</td>
<td>33</td>
</tr>
<tr>
<td>7. Greenwaste</td>
<td>278,750$^7$</td>
<td>90.4</td>
<td>25</td>
<td>18</td>
</tr>
<tr>
<td>8. Mixed Waste Paper</td>
<td>652,536$^7$</td>
<td>90.4</td>
<td>59</td>
<td>41</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,843,392 to 4,428,584</strong></td>
<td></td>
<td><strong>261 to 405</strong></td>
<td><strong>182 to 282</strong></td>
</tr>
</tbody>
</table>

$^2$ Skog et al 2008  
$^3$ Ethanol yield assumption is GREET value for forest residue gasification  
$^4$ Ethanol yield assumption is GREET value for corn stover  
$^5$ Walsh, 2000  
$^6$ Wright, 2009  
$^7$ Graf and Koehler 2000
5. Existing biofuels crops

Some existing Oregon crops could potentially be used for fuel production. Please note that currently, these crops have other uses.

Corn: Oregon’s corn for grain production in 2009 was 6,880,000 bushels (USDA, 2010). If this crop were used for fuel production, the yield would be 18,713,600 gallons per year of ethanol.\(^8\) This is 13 million gallons of gasoline equivalent.

Canola: In 2009, 11,220,000 lbs (5610 tons) of canola was produced in Oregon (USDA, 2010). This would yield 10 million 0.53 million gallons of biodiesel, which is 0.54 million gallons of gasoline equivalent produced from Oregon’s current crop of canola.\(^9\)

Other: According to USDA, Oregon also produces small amounts of sugarbeets (395,000 thousand tons in 2009) and sunflower oil (323,255 tons in 2007) (USDA, 2010). Because the amounts are so small, they are not included in the biomass totals.

6. Potential Biofuels Crops

Agriculture in Oregon is a robust industry that accounts for over 10% of the state’s sales and employs over 10% of Oregon jobs. The survival of both rural and urban communities depend on agriculture. (Farm Bureau, retrieved 2010). In 2007, approximately 3 million acres, or almost 5% of Oregon was dedicated to harvested cropland. (USDA, retrieved 2010)

\(^8\) Ethanol yield assumptions are based on GREET dry mill assumption of 2.72 gal/bushel
\(^9\) Canola yield assumptions are based on GREET soybean biodiesel assumption of 0.96 lb biodiesel/lb oil
Several biofuels crops could be grown in Oregon on existing agricultural cropland, which are not currently grown in large quantities, such as switchgrass, miscanthus, brassica juncea, sorghum, and camelina. In addition, there could be increased production of crops that are already grown in Oregon. These include corn, canola, camelina, hybrid poplar, and sugar beets. Estimating the amount of biofuels that could be produced by 2022 on existing croplands for biofuels production is outside the scope of this discussion paper.

Another potential source of cropland is retiring Conservation Reserve Program acres. Conservation Reserve Program is a farm program that retires acres from production for a certain amount of time in order to address soil, water, and related natural resource concerns on their lands. Over the next 10 years, many Conservation Reserve Program contracts may expire (depends somewhat on the 2012 Farm Bill). Some farmers may choose to re-enroll their land, but some may choose to return land to agricultural production, and program acreage limitations may prevent others from re-enrolling their land. There is potential for fuel production from some of these expired Conservation Reserve Program lands, however, some of these acres might not be returned to production or will be used to cultivate other crops. There are concerns with bringing this land into production because much of it is highly erodible or otherwise environmentally sensitive. The calculation of Conservation Reserve Program acres expiring from 2010 until 2019 is intended to illustrate the upper limit of fuel volume which could be produced if these expiring acres were used to produce biomass crops for fuel.

There are erosion, wildlife habitat, soil quality, and other concerns that would need to be taken into account if these acres were actually used for crops to produce fuel. In addition, cultivating expiring Conservation Reserve Program acres would have direct land use change impacts, but there is good potential for growing crops on some of this land. By 2019, over 540,000 acres of Conservation Reserve Program contracts are likely to expire in Oregon. (USDA Farm Services Agency, 2010)

In a presentation to the Washington State Department of Ecology, Pont (Pont, 2009) concluded that planting acreage for fuel production to Miscanthus would yield the highest production of biofuel per acre. Consequently, planting retired Conservation Reserve Program acres to Miscanthus could yield 363 million gallons of ethanol, which is equal to 239 million gallons of gasoline equivalent per year. This same acreage, if planted to camelina or brassica juncea, could yield 22 million gallons of biodiesel.
Appendix: Summary of Biomass Studies in Oregon

A. Biomass Energy and Biofuels from Oregon’s Forests. Prepared for Oregon Forest Resources Institute.

Authors: (Bowyer, Jim. 2006)


Please note that this study only covers 20 counties in Oregon. This study did not look statewide at biomass. Bowyer et al. (2006) looked at forest biomass available in 20 eastern and southern counties. This study did not estimate forest biomass in the Willamette valley.

This study excluded from consideration areas with low fire risk, over 30% slope, less merchantable timber, and roadless areas. It also estimates availability based on treatment options tailored to forest conditions.

Page 1-77 through 1-103 of this report contains a review of existing studies of biomass supply from fuel treatment thinning, logging residue, and other forest and woodland resources in Oregon.

<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Estimated Biomass Available (annual bone dry tons)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel treatment thinning- Eastern</td>
<td>Logging residues from forest restoration or timber stand improvement work – i.e.</td>
<td>1,000,000 - 2,000,000</td>
<td>Public and private forestland with high fire risk (not including Western Oregon forests or any wilderness, parks, roadless areas, etc.). Over 20 years. Cost would be $59 per dry ton delivered. See page 2-3.</td>
</tr>
<tr>
<td>and Southern Oregon</td>
<td>harvesting conducted primarily to reduce fire hazard or improve stand health</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary mill residue: Unused</td>
<td>Bark, coarse residues (chunk and slab) and fine residues (shavings and sawdust)</td>
<td>9,912</td>
<td>Does not include mill residue currently used for other purposes</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Estimated Biomass Available (annual bone dry tons)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wheat straw</td>
<td>Wheat straw available after soil conditioning</td>
<td>1,497,346</td>
<td>See page 12</td>
</tr>
<tr>
<td>Grass straw</td>
<td>Grass straw burned or chopped</td>
<td>500,000</td>
<td>See page 12</td>
</tr>
<tr>
<td>Greenwaste</td>
<td></td>
<td>278,750</td>
<td>See page 10</td>
</tr>
<tr>
<td>Mixed Waste Paper</td>
<td></td>
<td>652,536</td>
<td>See page 10</td>
</tr>
<tr>
<td>Wood and lumber</td>
<td></td>
<td>326,688</td>
<td>See page 10</td>
</tr>
<tr>
<td>Paper mill sludge</td>
<td></td>
<td>183,960</td>
<td>See page 10</td>
</tr>
<tr>
<td>Forest residues</td>
<td></td>
<td>2,940,000</td>
<td>See page 10</td>
</tr>
<tr>
<td>Agricultural residues</td>
<td></td>
<td>1,018,842</td>
<td>See page 10</td>
</tr>
</tbody>
</table>
C. Strategic Development of Bioenergy in the Western States: Biomass Resource Assessment and Supply Analysis for the WGA Region. 2008, Western Governors’ Association


The study covered forest biomass and agricultural residues such as wheat straw, corn stover and orchard prunings. This study considers sustainability in its estimates of available biomass. Skog et al. (2008) excluded forest types where the treatments contradicted the ecological objectives. See report for more information (link). Also, when estimating logging residue, Skog used allowable removal fractions to recognize the need to maintain nutrients and habitat on site. Lastly, when estimating agricultural residue (corn stover and wheat straw) Skog estimated available amount remaining after accounting for portion of residues needed to maintain soil health.

<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Low estimate (annual bone dry tons)</th>
<th>High estimate (annual bone dry tons)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forest Biomass</td>
<td>• Thinning of high fire hazard timberland</td>
<td>924,418</td>
<td>2,100,369</td>
<td>Availability varies depending on price paid for residues ($10/dry ton delivered to $100/dry ton delivered) with a low supply and a high supply case.</td>
</tr>
<tr>
<td></td>
<td>• Logging residue</td>
<td></td>
<td></td>
<td>Assumed biomass volumes would be harvested over 22-30 years.</td>
</tr>
<tr>
<td></td>
<td>• Treatment of Pinyon Juniper woodland</td>
<td></td>
<td></td>
<td>Base case and high case cover a range of uncertainty about the supply from sources.</td>
</tr>
<tr>
<td></td>
<td>• General thinning of private timberland</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Precommercial thinning on National forest land in western OR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Unused mill residue</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corn stover</td>
<td></td>
<td>2,899</td>
<td>8,458</td>
<td>Availability varies depending on the price paid for residues ($40/dry ton to $50/dry ton)</td>
</tr>
<tr>
<td>Material</td>
<td>Available (lbs)</td>
<td>Total Available (Mlbs)</td>
<td>Notes</td>
<td></td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-----------------</td>
<td>------------------------</td>
<td>---------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Winter wheat straw</td>
<td>185,274</td>
<td>453,012</td>
<td>Availability varies depending on the price paid for residues ($30/dry ton to $50/dry ton)</td>
<td></td>
</tr>
<tr>
<td>Spring wheat straw</td>
<td>6,099</td>
<td>20,355</td>
<td>Availability varies depending on the price paid for residues ($35/dry ton to $50/dry ton)</td>
<td></td>
</tr>
<tr>
<td>Orchard and vineyard pruning</td>
<td>94,564</td>
<td>94,564</td>
<td>This portion of the study did not look at availability based on price.</td>
<td></td>
</tr>
</tbody>
</table>


Available at: [http://bioenergy.ornl.gov/resourcedata/index.html](http://bioenergy.ornl.gov/resourcedata/index.html).

For forest residues, Walsh et al. (2000) estimated the total quantity of non-merchantable biomass residue available after a commercial harvest, then revise the inventory downward to reflect quantities that can actually be recovered based on road access, retrieval efficiencies, etc.

For agricultural residues, Walsh et al. (2000) estimated the total quantities of residues produced, then subtracted out the amount that must be left to maintain organic content and prevent erosion.

<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Estimated Biomass Available (annual bone dry tons)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forest residues (slash – tree tops, limbs, non-merchantable logs from timber harvest conducted primarily to produce merchantable timber)</td>
<td>Logging residues, rough rotten and salvable dead wood. Does NOT include: excess saplings and small pole trees</td>
<td>1,299,000 to 2,515,900</td>
<td>Availability varies depending on price paid for residues ($30/dry ton delivered to $50/dry ton delivered)</td>
</tr>
<tr>
<td>Mill residues (currently used at above 98%)</td>
<td>Bark, coarse residues (chunk and slab) and fine residues (shavings and sawdust)</td>
<td>10,000 to 6,834,000</td>
<td>Availability varies depending on price paid for residues ($20/dry ton delivered to $50/dry ton delivered) The high number assumes mill waste would be pulled from other uses.</td>
</tr>
</tbody>
</table>
### Agricultural residue
Stalks of corn stover and wheat straw
 estimated biomass available (annual bone dry tons): 155,855 to 155,855
Total quantity of residue produced minus the quantity that must be left to maintain soil quality (organic matter and erosion). $40/dry ton

### Urban wood wastes
Yard trimmings, site clearing wastes. Pallets, wood packaging, other miscellaneous commercial and household wood wastes, demolition and construction wastes
 estimated biomass available (annual bone dry tons): 182,532 to 304,220
Availability varies depending on price paid for residues ($20/dry ton delivered to $30/dry ton delivered)

---


**Authors:** Wright, L., B Boundy, P. Badger, B Perlack and S. Davis. 2009. (Wright, 2009)

**Available at:** [http://cta.ornl.gov/bedb/download.shtml](http://cta.ornl.gov/bedb/download.shtml)

<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Estimated Biomass Available (annual bone dry tons)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Unused</strong> Primary Mill Residue Production and Use</td>
<td>Bark, coarse residues (chunk and slab) and fine residues (shavings and sawdust)</td>
<td>16,320</td>
<td>This represents the unused .02 % of the 7,577,270 dry tons of mill residue produced in 2007 in Oregon.</td>
</tr>
</tbody>
</table>
## F. Oregon Department of Energy Website


<table>
<thead>
<tr>
<th>Type of biomass</th>
<th>What is included</th>
<th>Estimated Biomass Available</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wastewater Treatment</td>
<td>Unused biogas from wastewater treatment facilities.</td>
<td>600 million cubic feet of biogas is potentially available annually through anaerobic digestion technology</td>
<td>The Department of Energy estimates that, overall, as much as 36 percent of the biogas produced at Oregon’s wastewater treatment facilities is unused. This surplus biogas is a potential energy source.</td>
</tr>
<tr>
<td>Manure</td>
<td>This includes manure from the 111 dairies with 500 or more cows.</td>
<td>3,400 million cubic feet of biogas is potentially available annually through anaerobic digestion technology</td>
<td></td>
</tr>
<tr>
<td>Landfills</td>
<td>Based on EPA estimates of landfill gas available at candidate landfills.</td>
<td>4,600 million cubic feet of landfill gas is potentially available on an annual basis.</td>
<td>The US Environmental Protection Agency’s Landfill Methane Outreach Program has identified five landfills in Oregon as &quot;candidate&quot; landfills for production of electricity from landfill gas. The EPA selected these candidate landfills based on national data sources rather than on-site evaluation. More detailed assessment would be needed to determine the economic feasibility of developing a power generating facility at any of the state’s landfills.</td>
</tr>
</tbody>
</table>
Literature Cited


Appendix J: Credit and Deficit Calculations

Supporting Documentation for Calculating Credits and Deficits

Oregon Low Carbon Fuel Standards Report

Detailed Calculations: Overview and Examples

Credits and deficits will be calculated and expressed as metric tons of CO₂ equivalent. For purposes of understanding how credits and deficits would be calculated, this section provides an overview of the steps involved below, as well as six examples of credit and deficit calculation beginning on page 4.

Calculating credits and deficits involves several steps because the LCFS covers fuels with different energy intensities, including liquid and non-liquid fuels. Carbon intensity of fuels is expressed in grams of carbon dioxide equivalent per megajoule (g CO₂ E/MJ). This is so that the lifecycle emissions of different types of liquid and non-liquid fuels can be compared. In order to translate a volume of fuel sold at a certain carbon intensity into credits and deficits expressed in metric tons of CO₂ equivalent, several steps are involved. Oregon’s final rule regarding calculation of credits and deficits will address issues such as the number of significant digits and rounding.

Overview:

Step 1: Calculate the number of megajoules (MJ) of energy in the fuel sold

Explanation: Because different liquid fuels have different energy densities, or are in non-liquid form, a metric is needed to compare the carbon intensity of non-liquid and liquid fuels. To put all of the liquid and non-liquid fuels on equal footing, megajoules are used instead of gallons, standard cubic feet (scf), or kilowatt-hours (KWh). A table with energy densities in megajoules per unit of fuel is used to calculate the number of megajoules of energy in the fuel sold.

Formula: Multiply the volume [gallons, standard cubic feet (scf) of gas, or kilowatt-hours (KWh) of electricity depending on the fuel type sold] by the energy density of the fuel from the energy density table below.

\[
\text{Gallons of fuel (gallon) } \times \text{ energy density (MJ/gallon)} = \text{Number of MJ (MJ)}
\]

Or

\[
\text{Standard cubic feet of CNG (scf) } \times \text{ energy density (MJ/scf)} = \text{Number of MJ (MJ)}
\]

Or

\[
\text{Kilowatt-hours of electricity (KWh) } \times \text{ energy density (MJ/KWh)} = \text{Number of MJ (MJ)}
\]

Oregon Energy Density Table

---

1 A standard cubic foot (abbreviated as scf) is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and 14.696 psi of pressure.
### Oregon Energy Densities of Fuels

<table>
<thead>
<tr>
<th>Fuel (units)</th>
<th>MJ/gal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>116.09</td>
</tr>
<tr>
<td>Diesel fuel (gal)</td>
<td>129.49</td>
</tr>
<tr>
<td>CNG (scf)</td>
<td>.98</td>
</tr>
<tr>
<td>Electricity (KWh)</td>
<td>3.60</td>
</tr>
<tr>
<td>Anhydrous Ethanol (gal)</td>
<td>77.53</td>
</tr>
<tr>
<td>Neat Biomass-based diesel (gal)</td>
<td>119.55</td>
</tr>
</tbody>
</table>

**Step 2: Account for energy economy ratios, if necessary**

**Explanation:** Different types of vehicles use the energy in fuel more or less efficiently. For example, on average, an electric car will go three times farther than a gasoline vehicle on the same number of megajoules, while a heavy-duty natural gas vehicle will go only 94 percent as far as a diesel heavy-duty vehicle on the same number of megajoules. The Energy Economy Ratios (EERs) are used to adjust credits taking these differences into account. Below are both light-duty and heavy-duty tables of EERs. You can see that for some fuels, such as gasoline, E85, diesel or biomass-based diesel, the EER is 1.0, and the adjustment is unnecessary. Note: for more information on Energy Economy Ratios, see *Table 13: EER Values for Fuels Used in Light-Duty Applications* in the Oregon Low Carbon Fuel Standards Report.

**Formula:** Multiply the number of megajoules (MJ) in the fuel from Step 1 above by the energy economy ratio below.

\[
\text{Number of MJ from Step 1 (MJ)} \times \text{EER value from table} = \text{Adjusted number of MJ (MJ)}
\]
### Table: EER Values for Fuels Used in Light-Duty Applications

<table>
<thead>
<tr>
<th>Year</th>
<th>Gasoline or any ethanol blend</th>
<th>CNG / Internal combustion engine vehicle</th>
<th>Hydrogen or fuel cell vehicle</th>
<th>Electricity / battery electric vehicle, or plug-in hybrid electric vehicle</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>1.0</td>
<td>1.0 (needs to be adjusted: not reformulated gasoline)</td>
<td>3.0 (needs to be adjusted: not reformulated gasoline)</td>
<td>4.1</td>
</tr>
<tr>
<td>2013</td>
<td>1.0</td>
<td>1.0</td>
<td>3.0</td>
<td>4.0</td>
</tr>
<tr>
<td>2014</td>
<td>1.0</td>
<td>1.0</td>
<td>2.9</td>
<td>3.9</td>
</tr>
<tr>
<td>2015</td>
<td>1.0</td>
<td>TBA*</td>
<td>2.8</td>
<td>3.8</td>
</tr>
<tr>
<td>2016</td>
<td>1.0</td>
<td>TBA</td>
<td>2.8</td>
<td>3.7</td>
</tr>
<tr>
<td>2017</td>
<td>1.0</td>
<td>TBA</td>
<td>2.7</td>
<td>3.6</td>
</tr>
<tr>
<td>2018</td>
<td>1.0</td>
<td>TBA</td>
<td>2.6</td>
<td>3.5</td>
</tr>
<tr>
<td>2019</td>
<td>1.0</td>
<td>TBA</td>
<td>2.5</td>
<td>3.4</td>
</tr>
<tr>
<td>2020</td>
<td>1.0</td>
<td>TBA</td>
<td>2.5</td>
<td>3.3</td>
</tr>
<tr>
<td>2021</td>
<td>1.0</td>
<td>TBA</td>
<td>2.4</td>
<td>3.2</td>
</tr>
<tr>
<td>2022</td>
<td>1.0</td>
<td>TBA</td>
<td>2.3</td>
<td>3.1</td>
</tr>
</tbody>
</table>

* In the 2014 review, DEQ will research what the EER for light-duty CNG should be after 2014.

Data in this table is based on: California Environmental Protection Agency Air Resources Board. Appendices, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. 2. Appendix C, pages C-5 through C-12. Released Date March 4, 2009.

### Table: EER Values for Fuels Used in Heavy-Duty Applications

<table>
<thead>
<tr>
<th>Fuel/Vehicle Combination</th>
<th>Energy Economy Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel fuel Or Biomass-based diesel blends</td>
<td>1.0</td>
</tr>
</tbody>
</table>

*DEQ will research what the EER for all heavy-duty applications should be in future years in the 2014 review.

Data in this table is based on: California Environmental Protection Agency Air Resources Board. Appendices, Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol. 2. Appendix C, pages C-5 through C-12. Released Date March 4, 2009.

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

**Explanation:** Comparing the low carbon fuel standard for the year in question to the carbon intensity of a given fuel indicate whether selling the fuel will generate credits or deficits, and whether selling the fuel will generate a relatively large or small number of credits or deficits.

**Formula:** Subtract the carbon intensity (CI) of the fuel sold from the carbon intensity required by the low carbon fuel standard.

\[ CI_{standard} \ (g\text{CO}_2\text{E/MJ}) - CI_{fuel\ sold} \ (g\text{CO}_2\text{E/MJ}) = CI\ difference \ (g\text{CO}_2\text{E/MJ}) \]
Negative numbers mean there is a deficit because the fuel exceeds the standard, while positive numbers mean there are credits because the fuel’s carbon intensity is less than the standard.

**Step 4: Calculate the credits/deficits in grams of CO$_2$ equivalent**

**Explanation:** Credits and deficits are expressed in volumes of greenhouse gas emissions, where credits show the emissions “saved” by selling a low carbon fuel compared to selling a fuel that exactly meets the low carbon fuel standard for that year. Deficits, by comparison, show the “excess” emissions incurred by selling a fuel whose carbon intensity is higher than the low carbon fuel standard, compared to selling a fuel that exactly meets the standard for that year. In this step, emissions are calculated in grams of CO$_2$ equivalent, while in the next step emissions are converted into metric tons of CO$_2$ equivalent. CO$_2$ equivalent, or CO$_2$E, is a unit of measurement that combines CO$_2$ and other greenhouse gases like methane and nitrous oxide into one number. It describes, for a given mixture and amount of greenhouse gases, the amount of CO$_2$ that would have the same global warming potential.

**Formula:** Multiply the number of megajoules in the fuel sold (calculated in Step 2) by the carbon intensity difference (calculated in Step 3).

\[
\text{Number of MJ (MJ)} \times \text{CI difference (gCO}_2\text{E/MJ)} = \text{number of grams CO}_2\text{ E (gCO}_2\text{E)}
\]

**Step 5: Convert the grams of CO$_2$ equivalent into metric tons of CO$_2$ equivalent**

**Explanation:** Greenhouse gas emissions are most commonly expressed in metric ton units. There are 1,000,000 grams per metric ton (g/metric ton), so the final step in the calculation is to divide the result from step 4 by 1,000,000.

**Formula:** Divide the number of grams of carbon dioxide equivalent in step 4 by 1,000,000.

\[
\text{Number of grams CO}_2\text{ E (gCO}_2\text{E)} \div 1,000,000 \text{ (g/metric ton)} = \text{Number of metric tons CO}_2\text{E (metric tons CO}_2\text{e)}
\]

**Examples**

**Example 1: Ethanol**

In 2014, a regulated party sells 20 million gallons of ethanol with a carbon intensity of 64.82 gCO$_2$E/MJ in 2014, when the low carbon fuel standard is 89.93 gCO$_2$E/MJ. (*Note: This example is provided for illustration purposes and does not include indirect land use. The actual carbon intensity may be subject to change after the 2014 comprehensive program review.*)

**Step 1: Calculate the number of megajoules of energy in the fuel sold**

**Formula:** Multiply the gallons of fuel sold by the energy density of the fuel from the energy density table on Page 2.
20,000,000  Volume of fuel (gallons)
X  77.53  Energy density (MJ/gallon, from Energy Densities table)
= 1,550,600,000  MJ

Step 2: Account for energy economy ratios, if necessary

Formula: Multiply the number of MJ in the fuel from Step 1 above by the energy economy ratio from table on Page 2.

\[
\begin{align*}
1,550,600,000 & \quad \text{Number of MJ from Step 1 (MJ)} \\
\times & \quad \text{EER value from table} \\
= & \quad \text{Adjusted number of MJ (MJ)}
\end{align*}
\]

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

Formula: Subtract the carbon intensity (CI) of the fuel sold from the carbon intensity required by the standard.

\[
\begin{align*}
89.93 & \quad \text{CI of standard (gCO}_2\text{E/MJ)} \\
- 64.82 & \quad \text{CI of fuel sold (gCO}_2\text{E/MJ)} \\
= & \quad \text{CI difference (gCO}_2\text{E/MJ)}
\end{align*}
\]

Step 4: Calculate the credits/deficits in grams of CO\textsubscript{2} equivalent

Formula: Multiply the number of megajoules in the fuel sold (calculated in Step 2) times the carbon intensity difference (calculated in Step 3).

\[
\begin{align*}
1,550,600,000 & \quad \text{Number of MJ (MJ)} \\
\times & \quad \text{CI difference (gCO}_2\text{E/MJ)} \\
= & \quad \text{Number of grams CO}_2\text{E (gCO}_2\text{E)}
\end{align*}
\]

Step 5: Convert the grams of CO\textsubscript{2} equivalent into tons of CO\textsubscript{2} equivalent

Formula: Divide the number of grams of carbon dioxide equivalent in step 4 by 1,000,000 g/ton to convert the number of grams into metric tons.

\[
\begin{align*}
38,935,566,000 & \quad \text{Number of grams CO}_2\text{E (gCO}_2\text{E)} \\
\div 1,000,000 & \quad \text{1,000,000 grams = 1 metric ton (g/metric ton)} \\
= & \quad \text{Number of metric tons CO}_2\text{E (metric tons CO}_2\text{E)}
\end{align*}
\]

The final result is 38,936 metric tons CO\textsubscript{2}E CREDITS. Because this number is positive, it is a credit, and can be sold or banked.

Example 2: Diesel and Renewable Diesel

In 2014, the low carbon fuel standard for diesel is 89.55 gCO\textsubscript{2}E/MJ. (Note: This example is provided for illustration purposes and does not include indirect land use. The actual carbon intensity may be subject to change after the 2014 comprehensive program review.)

A regulated party sells:
- 25 million gallons of diesel with a carbon intensity of 91.53 gCO\textsubscript{2}E/MJ
- 4.5 million gallons of renewable diesel with a carbon intensity of 21.66 gCO\textsubscript{2}E/MJ
The credits and deficits are calculated separately for each fuel.

**Diesel calculations**

Step 1: Calculate the number of megajoules of energy in the fuel sold

\[ 25,000,000 \text{ Volume of fuel (gallons)} \times 129.49 \text{ Energy density (MJ/gallon, from Energy Densities table)} = 3,237,250,000 \text{ MJ} \]

Step 2: Account for energy economy ratios, if necessary. *EER is 1.0, no adjustments necessary*

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

\[ 89.55 \text{ CI of standard (gCO}_2\text{E/MJ)} \]
\[ -21.53 \text{ CI of fuel sold (gCO}_2\text{E/MJ)} \]
\[ = -67.98 \text{ CI difference (gCO}_2\text{E/MJ)} \]

Step 4: Calculate the credits/deficits in grams of CO\(_2\) equivalent

\[ 3,237,250,000 \text{ Number of MJ (MJ)} \times -67.98 \text{ CI difference (gCO}_2\text{E/MJ)} = -6,409,755,000 \text{ Number of grams CO}_2\text{E (gCO}_2\text{E)} \]

Step 5: Convert the grams of CO\(_2\) equivalent into tons of CO\(_2\) equivalent

\[ \frac{-6,409,755,000}{1,000,000} = -6,410 \text{ Number of metric tons CO}_2\text{E (metric tons CO}_2\text{E)} \]

The final result is -6,410 metric tons CO\(_2\)E deficit.

**Renewable diesel calculations**

Step 1: Calculate the number of megajoules of energy in the fuel sold

\[ 4,500,000 \text{ Volume of fuel (gallons)} \times 129.49 \text{ Energy density (MJ/gallon, from Energy Densities table)} = 582,705,000 \text{ MJ} \]

Step 2: Account for energy economy ratios, if necessary. *EER is 1.0, no adjustments necessary*

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

\[ 89.55 \text{ CI of standard (gCO}_2\text{E/MJ)} \]
\[ -21.66 \text{ CI of fuel sold (gCO}_2\text{E/MJ)} \]
\[ = 67.89 \text{ CI difference (gCO}_2\text{E/MJ)} \]

*Note: The standard used above is subject to change pending analysis of indirect land use change during the 2014 comprehensive program review.*
Step 4: Calculate the credits/deficits in grams of CO$_2$ equivalent

\[
\text{582,705,000} \times 67.89 = 39,559,842,450
\]

Step 5: Convert the grams of CO$_2$ equivalent into tons of CO$_2$ equivalent

\[
\frac{39,559,842,450}{1,000,000} = 39,560
\]

The final result is 39,560 metric tons CO$_2$E of credit.

NET RESULT: The regulated party would then subtract their 6,410 metric tons deficit from their 39,560 metric tons credit, and have a CREDIT of 33,150 metric tons.
Example 3: Electric vehicles

In 2014, the low carbon fuel standard is 89.93 g CO₂ E/MJ. (Note: This example is provided for illustration purposes and does not include indirect land use. The actual carbon intensity may be subject to change after the 2014 comprehensive program review.) An electric utility supplies electricity to 400 electric light-duty cars that used a total of 2,810,000 kilowatt-hours (KWh) of electricity at a carbon intensity (adjusted for energy economy ratio) of 39.73 gCO₂E/MJ.

Step 1: Calculate the number of megajoules of energy in the fuel sold

\[
\begin{align*}
2,810,000 & \quad \text{Volume of fuel (KWh)} \\
\times 3.60 & \quad \text{Energy density (MJ/KWh, from Energy Densities table)} \\
= 10,116,000 & \quad \text{MJ}
\end{align*}
\]

Step 2: Account for energy economy ratios, if necessary

\[
\begin{align*}
10,116,000 & \quad \text{Number of MJ from Step 1 (MJ)} \\
\times 3.9 & \quad \text{EER value from table} \\
= 39,452,400 & \quad \text{Adjusted number of MJ (MJ)}
\end{align*}
\]

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

\[
\begin{align*}
89.93 & \quad \text{CI of standard (gCO₂E/MJ)} \\
-39.73 & \quad \text{CI of fuel sold (gCO₂E/MJ)} \\
= 50.2 & \quad \text{CI difference (gCO₂E/MJ)}
\end{align*}
\]

Step 4: Calculate the credits/deficits in grams of CO₂ equivalent

\[
\begin{align*}
39,452,400 & \quad \text{Number of MJ (MJ)} \\
\times 50.2 & \quad \text{CI difference (gCO₂E/MJ)} \\
= 1,980,510,480 & \quad \text{Number of grams CO₂E (gCO₂E)}
\end{align*}
\]

Step 5: Convert the grams of CO₂ equivalent into metric tons of CO₂ equivalent

\[
\begin{align*}
1,980,510,480 & \quad \text{Number of grams CO₂E (gCO₂E)} \\
\div 1,000,000 & \quad 1,000,000 \text{ grams} = 1 \text{ metric ton (g/metric ton)} \\
= 1,981 & \quad \text{Number of metric tons CO₂E (metric tons CO₂E)}
\end{align*}
\]

\textit{Final result is 1,981 metric tons CO₂ E CREDIT.} Because this number is positive, it is a credit, and can be sold or banked.
Example 4: Regulated party excludes fuel sold to exempted uses from credit and deficit calculations

In 2014, the low carbon fuel standard for diesel is 89.55 g CO₂ E/MJ. (Note: This example is provided for illustration purposes and does not include indirect land use. The actual carbon intensity may be subject to change after the 2014 comprehensive program review.) A regulated party sells 28 million gallons of diesel and 560,000 gallons of biodiesel from waste oil in 2014 to both farm and non-farm uses, as indicated below (and sells no other transportation fuels). This is a blend of two percent biodiesel. The credits and deficits are calculated separately for each fuel.

**Diesel calculations**

The regulated party sells 28 million gallons of diesel with a carbon intensity of 91.53 g CO₂ E/MJ. However, of those 28 million gallons, 3 million gallons were sold to farm coops, and the regulated party demonstrated the fuel was farm use. (Farm uses of fuel are exempt under HB 2186.) The regulated party would then calculate deficits only on the remaining 25 million gallons of diesel which was not sold for farm use. The final deficit calculation would be **6,410 metric tons of deficit** (see diesel calculations for Example 2 on page 5).

**Biodiesel calculations**

The regulated party sells 611,200 gallons of biodiesel from waste oil (yellow grease average) with a carbon intensity of 10.28 g CO₂ E/MJ. Of this amount, 11,200 gallons were sold to exempt farm uses. The regulated party would then only calculate credits for the remaining 600,000 gallons which were not sold for farm use.

**Step 1: Calculate the number of megajoules of energy in the fuel sold**

\[
600,000 \times 119.55 = 71,730,000 \text{ MJ}
\]

**Step 2: Account for energy economy ratios, if necessary.** EER is 1.0, no adjustments necessary

**Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold**

\[
91.53 - 10.28 = 81.25 \text{ CI difference (gCO₂ E/MJ)}
\]

**Step 4: Calculate the grams of CO₂ equivalent**

\[
71,730,000 \times 81.25 = 5,828,062,500 \text{ Number of grams CO₂ E (gCO₂ E)}
\]

**Step 5: Convert the grams of CO₂ equivalent into metric tons of CO₂ equivalent**

\[
5,828,062,500 \div 1,000,000 = 5,828 \text{ metric tons CO₂ E (metric tons CO₂ E)}
\]

NET RESULT: The regulated party would then subtract their **6,410 metric tons deficit** from their **5,828 metric tons credit**, and have a **DEFICIT of 582 metric tons**. Because this deficit is under ten percent (10%) of their total deficit for the year, this regulated party can carry over the deficit to the following year (5,828 metric tons of deficit is 9.09% of 6,410 metric tons of deficit).
Example 5: Diesel and low carbon biodiesel sold to farm uses where a regulated party does not claim any exemptions

In 2014, the low carbon fuel standard is 89.55 gCO2E/MJ. (Note: This example is provided for illustration purposes and does not include indirect land use. The actual carbon intensity may be subject to change after the 2014 comprehensive program review.) A regulated party sells 28 million gallons of diesel and 560,000 gallons of biodiesel in 2014, as indicated below (and sells no other transportation fuels). This is a blend of two percent biodiesel. The credits and deficits are calculated separately for each fuel.

Diesel calculations

The regulated party elects to NOT claim exemptions for fuel sold for farm uses in 2014. Hence, credits/deficits for diesel are calculated on the full 28 million gallons of diesel sold.

Step 1: Calculate the number of megajoules of energy in the fuel sold

\[
\begin{align*}
28,000,000 & \quad \text{Volume of fuel (gallons)} \\
\times 129.49 & \quad \text{Energy density (MJ/gallon, from Energy Densities table)} \\
= 3,625,720,000 & \quad \text{MJ}
\end{align*}
\]

Step 2: Account for energy economy ratios, if necessary. EER is 1.0, no adjustments necessary

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

\[
\begin{align*}
89.55 & \quad \text{CI of standard (gCO2E/MJ)} \\
-91.53 & \quad \text{CI of fuel sold (gCO2E/MJ)} \\
-1.98 & \quad \text{CI difference (gCO2E/MJ)}
\end{align*}
\]

Step 4: Calculate the credits/deficits in grams of CO2 equivalent

\[
\begin{align*}
3,625,720,000 & \quad \text{Number of MJ (MJ)} \\
\times -1.98 & \quad \text{CI difference (gCO2E/MJ)} \\
= -7,178,925,600 & \quad \text{Number of grams CO2E (gCO2E)}
\end{align*}
\]

Step 5: Convert the grams of CO2 equivalent into tons of CO2 equivalent

\[
\begin{align*}
-7,178,925,600 & \quad \text{Number of grams CO2E (gCO2E)} \\
\div 1,000,000 & \quad 1,000,000 \text{ grams} = 1 \text{ metric ton (g/metric ton)} \\
= -7,179 & \quad \text{Number of metric tons CO2E (metric tons CO2E)}
\end{align*}
\]

Renewable diesel calculations

The regulated party elects to NOT claim exemptions for fuel sold for farm uses in 2014. Hence, credits/deficits for diesel are calculated on the full 560,000 gallons of biodiesel sold.
Step 1: Calculate the number of megajoules of energy in the fuel sold

\[
\begin{align*}
560,000 & \quad Volume \ of \ fuel \ (gallons) \\
\times 129.49 & \quad Energy \ density \ (MJ/gallon, \ from \ Energy \ Densities \ table) \\
= 72,514,400 & \quad MJ
\end{align*}
\]

Step 2: Account for energy economy ratios, if necessary. \textit{EER is 1.0, no adjustments necessary}

Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold

\[
\begin{align*}
89.55 & \quad CI \ of \ standard \ (gCO_2E/MJ) \\
- 21.66 & \quad CI \ of \ fuel \ sold \ (gCO_2E/MJ) \\
= 67.89 & \quad CI \ difference \ (gCO_2E/MJ)
\end{align*}
\]

Step 4: Calculate the credits/deficits in grams of CO\textsubscript{2} equivalent

\[
\begin{align*}
72,514,400 & \quad Number \ of \ MJ \ (MJ) \\
\times 67.89 & \quad CI \ difference \ (gCO_2E/MJ) \\
= 4,923,002,616 & \quad Number \ of \ grams \ CO_2E \ (gCO_2E)
\end{align*}
\]

Step 5: Convert the grams of CO\textsubscript{2} equivalent into tons of CO\textsubscript{2} equivalent

\[
\begin{align*}
4,923,002,616 & \quad Number \ of \ grams \ CO_2E \ (gCO_2E) \\
\div 1,000,000 & \quad 1,000,000 \ grams = 1 \ metric \ ton \ (g/metric \ ton) \\
= 4,923 & \quad Number \ of \ metric \ tons \ CO_2E \ (metric \ tons \ CO_2E)
\end{align*}
\]

The regulated party would then subtract their \textbf{7,179 metric tons deficit} from their \textbf{4,923 metric tons credit}, and have a \textbf{DEFICIT of 2,256 metric tons}. Because this deficit is over ten percent (10\%) of their total deficit for the year, this regulated party cannot carry over the deficit to the following year (4,923 metric tons of deficit is 68.57\% of 7,179 metric tons of deficit). They would need to purchase credits to cover the deficit, or use banked credits from previous years.
**Example 6: Gasoline**

In 2014, a regulated party sells 200 million gallons of gasoline with a carbon intensity of 92.34 gCO$_2$E/MJ and 20 million gallons of Midwest corn ethanol with a carbon intensity of 64.82 gCO$_2$E/MJ (and no other transportation fuels).

**Gasoline calculations**
The regulated party sells 200 million gallons of gasoline with a carbon intensity of 92.34 gCO$_2$E/MJ.

1. **Step 1: Calculate the number of megajoules of energy in the fuel sold**
   
   \[
   200,000,000 \times 116.09 = 23,218,000,000 \text{ MJ}
   \]

2. **Step 2: Account for energy economy ratios, if necessary.** EER is 1.0, no adjustments necessary

3. **Step 3: Calculate the difference in the carbon intensity between the low carbon fuel standard and the fuel sold**
   
   \[
   89.93 - 92.34 = -2.41 \text{ gCO}_2\text{E/MJ}
   \]

4. **Step 4: Calculate the grams of CO$_2$ equivalent**
   
   \[
   23,218,000,000 \times -2.41 = -55,955,380,000 \text{ gCO}_2\text{E}
   \]

5. **Step 5: Convert the grams of CO$_2$ equivalent into metric tons of CO$_2$ equivalent**
   
   \[
   -55,955,380,000 \div 1,000,000 = 37,369 \text{ metric tons CO}_2\text{E}
   \]

**Ethanol calculations**
The regulated party sells 20 million gallons of ethanol with a carbon intensity of 64.82 gCO$_2$E/MJ. Which generates **38,936 metric tons of credit in 2014**. (See ethanol calculations for Example 1 on page 4.)

**NET RESULT:** The regulated party would then subtract their **37,369 metric tons deficit** from their **38,936 metric tons credit**, and have a **CREDIT of 1,567 metric tons**.
Appendix K: Review of Biodiesel and Renewable Diesel Use Considerations

Oregon Low Carbon Fuel Standards Report

BACKGROUND

What are renewable fuels?
According to the Environmental Protection Agency’s new Renewable Fuel Standard, renewable fuels are defined as motor vehicle fuels produced from plant or animal products or wastes. Within this definition, two distinct forms of diesel fuel are specified: biodiesel and renewable diesel. Each is defined according to the process by which it is produced. The term “biodiesel” is often used very broadly to refer to any blend of conventional petroleum diesel with any renewable diesel product. In order to avoid confusion, the term biodiesel should be used in reference to pure biodiesel fuel meeting the ASTM D6571 standard. Mixtures of biodiesel with petroleum should be referred to as biodiesel blends (i.e. B20, as explained below in the section titled, *What is a biodiesel blend?*).

What is biodiesel?
Biodiesel is a diesel fuel alternative that is made from renewable resources, such as vegetable oils or animal fats. The most common feedstock for biodiesel in the US is soybean oil, although palm oil, canola oil, poultry renderings, beef tallow, and waste grease also may be used to make biodiesel. Biodiesel is made through a chemical process called transesterification, whereby vegetable oil is mixed with methanol in the presence of a catalyst (sodium hydroxide) to produce a diesel fuel alternative. The resulting liquid must then be further processed to remove glycerin and excess methanol. To be designated as biodiesel the alternative fuel must meet the American Society of Testing Materials (ASTM) D6751 quality standards (discussed below), compliance with which assures that biodiesel may be used in low percentage blends without causing problems for the diesel engine. Low percentage blends of high-quality biodiesel may be used in compression-ignition (diesel) engines with little or no modifications. Biodiesel is biodegradable, nontoxic, and essentially free of sulfur and aromatics.

What is renewable diesel?
Renewable diesel is a diesel fuel alternative that is made from renewable resources, such as vegetable oils or animal fats. Renewable diesel is sometimes referred to as second or third generation biodiesel, depending upon the production process utilized. The primary differences between biodiesel and renewable diesel are the technologies used to make the fuel and the molecules that are ultimately produced. Whereas, biodiesel is made using a chemical reaction called transesterification, renewable diesel is made using a thermal or other chemical reaction. There are currently two processing means for producing renewable diesel: stand alone and co-processing. Co-processed renewable diesel is diesel fuel produced from animal fats and/or vegetable oil by blending with petroleum feedstock and hydrotreating within an existing petroleum refinery. It has been in commercial production in the United States and Ireland since 2005, and is sold as diesel fuel. The resulting diesel fuel product is a fully fungible fuel that can be transported via pipeline.
The most significant difference between biodiesel and renewable diesel is that renewable diesel can meet the ASTM D975 quality standard, which is the existing standard for on-road diesel fuel. Renewable diesel has been subjected to rigorous on-road fleet testing during the Canada’s Alberta Renewable Diesel Demonstration project in December 2007 through September 2008.¹ Preliminary information indicates that renewable diesel may have advantages over biodiesel for the end-user. These advantages may include a higher energy content and better cold weather performance compared to biodiesel.

### What is a biodiesel blend?
Both biodiesel and renewable diesel are blend stocks that are typically mixed with petroleum diesel fuel to produce a biodiesel/renewable diesel blend. Biodiesel (or neat biodiesel) refers to the pure fuel before blending with diesel fuel. Biodiesel and renewable blends are denoted as, "BXX" or “RXX” with "XX" representing the percentage of biodiesel contained in the blend (i.e., B10 is 10% biodiesel, 90% petroleum diesel or R10 which is 10% renewable diesel, 90% petroleum diesel).

Unless specifically noted, when the term biodiesel is used in the remainder of this document it is referring to both biodiesel and renewable diesel synonymously.

### TRUCKS:

**OPERABILITY/PERFORMANCE**

**Are there advantages to using biodiesel?** As defined earlier, Biodiesel offers significant environmental benefits, which are discussed in more detail below. Biodiesel also may be used to increase the lubricity of diesel fuel. A B2 blend may be sufficient to restore the lubricity lost in

¹ Alberta Renewable Diesel Demonstration, http://www.renewablediesel.ca
the Ultra Low Sulfur Diesel (ULSD) refining process. Standard lubricating additives may be used with renewable diesel.

**How will biodiesel affect fuel economy?** Neat biodiesel (B100) has about a 9% lower energy content (BTU content) than petroleum-based diesel. A B5 blend would likely reduce fuel economy by less than one percent and may not be measurable in an individual truck. Use of a B20 blend is expected to reduce fuel economy by two percent when compared to ultra low sulfur diesel. Across the entire fleet the use of biodiesel will require end-users to purchase more fuel to perform the same amount of work. Renewable diesel proponents have indicated that there is no difference in the BTU value of renewable diesel when compared to petroleum-based diesel.

**Will biodiesel work in all climates?** Biodiesel offers reduced cold weather performance compared to ultra-low-sulfur diesel. While the cloud point and pour point of petroleum diesel fuel varies greatly, generally ULSD will turn gelatinous at 16ºF. B100 derived from soy bean oil will typically turn gelatinous at 32ºF. B20 will raise the cloud point of the base fuel by 3º - 10ºF. Low percentage blends (<B5) should perform comparably to petroleum based diesel. Different feedstocks will have different cold weather performance capabilities. Biodiesel derived from canola oil will have better cold-flow properties than biodiesel derived from soy. Biodiesel derived from animal tallow will have poor cold weather performance compared to soy-based biodiesel. Canada’s largest cold-weather demonstration of renewable diesel has shown that levels less than 5% by volume of canola-derived renewable diesel blended with petroleum diesel will work. It can be blended, distributed and used without problems, even in a bitter Alberta winter, using normal commercial facilities.

**Will biodiesel require any additional vehicle maintenance?** Biodiesel blends tend to act like a solvent and will clean out the sediment that naturally accumulates in diesel fuel systems. For this reason, use of biodiesel will require end-users to closely monitor their fuel filters and likely will require a fuel filter change that coincides with the initial introduction of biodiesel. Subsequent fuel filter changes may need to occur ahead of regularly scheduled maintenance until the fuel system is free from accumulated sediment. Biodiesel tends to attract water in fuel tanks and storage systems and may require replacement of hose and sealing equipment due to incompatibility with some older engines. As for other renewable diesel fuels, many of the challenges related to the fuel system and injectors should be alleviated since they are pure hydrocarbons which have similar performance to petroleum diesel.

**Will biodiesel affect the vehicle or equipment warranty?** All diesel engine Original Equipment Manufacturers (OEMs) warranty the product they make – engines. They warranty their engines against defects in “material or workmanship.” If there is a problem with an engine part or with engine operation due to an error in manufacturing or assembly within the prescribed warranty period, the problem will be covered by the engine company. They do not warrant the fuel that is used in the engines.

Typically, an engine company will define what fuel the engine was designed for and will recommend the use of that fuel to their customers in their owner's manuals. Engine companies do not manufacture fuel or fuel components. Therefore, engine companies do not warranty fuel - whether that fuel is biodiesel, renewable diesel or petroleum diesel fuel. Since engine
manufacturers warranty the materials and workmanship of their engines, they do not warranty fuel of any kind. If there are engine problems caused by a fuel (again, whether that fuel is petroleum diesel fuel, renewable diesel fuel or biodiesel fuel) these problems are not related to the materials or workmanship of the engine, but are the responsibility of the fuel supplier and not the engine manufacturer. Any reputable fuel supplier (biodiesel, petroleum diesel, or a blend of both) should stand behind its products and cover any fuel quality problems if they occur.

Therefore, the most important aspect regarding engine warranties and biodiesel or renewable diesel is whether an engine manufacturer will void its parts and workmanship warranty when biodiesel or renewable diesel is used, and whether the fuel producer or marketer will stand behind its fuels should problems occur.

Most major engine companies have stated formally that the use of blends up to B20 will not void their parts and workmanship warranties provided that the biodiesel used conforms to the ASTM D6751 standard and it is blended with diesel fuel that meets ASTM D975 specifications. This includes blends below 20% biodiesel, such as the 2% biodiesel blends that are becoming more common. Several statements from the engine companies are available on websites; a good website is the National Biodiesel Board website. It is anticipated that the entire industry will incorporate the ASTM biodiesel standard into their owner's manuals over time. Renewable diesel that meets the ASTM D975 specifications will have no impact on manufacturers’ warranties.

Are certain materials incompatible with biodiesel? Natural rubber, nitrile and butyl rubber are particularly susceptible to degradation when exposed to high percentage biodiesel blends. Also, copper, bronze, brass, tin, lead and zinc can cause deposit formations. The use of these materials and coatings must be avoided for fuel tanks and fuel lines. OEMs recommend that questions or concerns regarding the use of biodiesel or biodiesel blends be directed to the vehicle manufacturer to determine if any of the OEM-supplied engine components are at risk of voiding warranty coverage in order to prevent engine or vehicle damage.

QUALITY

Are there accepted biodiesel specifications to measure its suitability for use in a truck? The only accepted biodiesel specification in the US is the ASTM D6751 specifications applicable to neat biodiesel (B100). ASTM is in the process of developing specifications for specific biodiesel blends; however, this process is not yet complete. The incorporation of biodiesel that meets the ASTM D6751 specifications into ULSD in amounts up to 5% should produce a high quality biodiesel blend that is suitable for use in heavy duty diesel engines.

Are there fuel quality issues associated with biodiesel? Quality control is one of the most significant challenges facing biodiesel distribution in the United States. It is relatively easy to make biodiesel; however, it is rather difficult to consistently manufacture high quality biodiesel. Biodiesel producers are a diverse group. Some facilities look like modern petroleum refineries

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and have deployed quality controls including on-site testing laboratories. Other producers utilize small batch systems where quality may vary significantly from batch-to-batch. In 2006, the National Renewable Energy Laboratory conducted a random survey of biodiesel producers and found that 50% of the samples taken failed to meet the applicable ASTM quality specifications.\(^3\)

**How does the buyer know whether biodiesel meets the specification?** Short of sending a sample to a fuel testing laboratory, there is no way for the end-user to tell whether biodiesel blends meet the appropriate quality standards. For this reason, it is important to purchase biodiesel only from producers or distributors that are committed to producing on-spec product. Many biodiesel producers are testing each batch of fuel and can furnish a purchaser with a certificate of analysis that demonstrates compliance with the applicable ASTM specifications.

The National Biodiesel Board, the trade association for the biodiesel industry, has formed the National Biodiesel Accreditation Commission (NBAC) to audit fuel producers and marketers in order to improve the quality of biodiesel production and handling throughout marketing channels in the US. NBAC issues a 'Certified Biodiesel Marketer' seal of approval for biodiesel marketers that have met all requirements of fuel accreditation audits and a quality assurance program called BQ-9000. Companies that are BQ-9000 certified have demonstrated that they are capable of consistently producing high quality biodiesel and have implemented quality assurance controls. This seal of approval will provide added assurance to customers, as well as engine manufacturers, that the biodiesel marketed by these companies meets the ASTM standards for biodiesel and that the fuel supplier will stand behind its products. The steps taken by the biodiesel industry to work with the engine companies and to ensure that fuel meets the newly accepted ASTM standards provides confidence to users and engine manufacturers that their biodiesel experiences will be positive and trouble-free.

**Who is responsible for enforcement of the biodiesel standard?**\(^4\) Biodiesel quality enforcement can occur at several different levels (e.g. federal and state). Unfortunately, there hasn’t been a concerted push to ensure biodiesel quality through an enforcement program.

Biodiesel has been registered for sale as a motor vehicle fuel with the US Environmental Protection Agency. As such, EPA has the legal authority to ensure that all biodiesel offered for sale complies with the ASTM D6751 specifications. The sale of off-spec biodiesel is a violation of the Clean Air Act and subjects the person to civil penalties not to exceed $32,500 per violation.

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 - Top Crop Manager, http://www.topcropmanager.com/content/view/4991/60/
 - U.S. Environmental Protection Agency, www.epa.gov/OMS/models/biodsl.htm
Only biodiesel that meets ASTM D6751 is eligible for the $1 per gallon federal tax credit. As such, the IRS has the legal authority to pursue individuals claiming the tax credit on biodiesel that does not comply with the ASTM D6751 specifications.

Finally, each state, usually through its department of weights and measures, has the authority to ensure that fuel dispensed meets applicable requirements. Most states have not devoted the resources necessary to create a robust on-spec biodiesel inspection and enforcement program, with the Minnesota Biodiesel Program being the exception.

**What resources are available to address potential biodiesel quality issues?** Damages caused by off-spec biodiesel are difficult to prove for a variety of reasons, including the fact that the damage may not occur immediately upon refueling and the fuel used in an individual truck may be purchased from several different suppliers. If an end-user can identify that a particular problem was caused by a specific biodiesel provider, the end-user may initiate a legal claim against that fuel provider. In addition, EPA, the IRS, and the appropriate state enforcement authority should be notified.

**ENVIRONMENTAL ISSUES**

**What impact does biodiesel have on tailpipe emissions?** Biodiesel offers numerous environmental benefits, including reduced particulate matter and hydrocarbon emissions. A life cycle analysis of biodiesel shows that the fuel significantly reduces greenhouse gas emissions. There is an ongoing debate as to the impact biodiesel has on nitrogen oxide emissions, with EPA concluding that biodiesel causes a slight increase in the emissions of this ozone precursor. Neat biodiesel contains no hazardous materials and biodegrades more rapidly than ULSD.

<table>
<thead>
<tr>
<th>Emission Type</th>
<th>B100</th>
<th>B20</th>
<th>B2</th>
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<tbody>
<tr>
<td>PM</td>
<td>(47%)</td>
<td>(20%)</td>
<td>(2.2%)</td>
</tr>
<tr>
<td>NOx</td>
<td>+10%</td>
<td>+2%</td>
<td>+0.2%</td>
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</tr>
<tr>
<td>CO2</td>
<td>(71%)</td>
<td>(14%)</td>
<td>(1.4%)</td>
</tr>
<tr>
<td>HC</td>
<td>(67%)</td>
<td>(20%)</td>
<td>(2.2%)</td>
</tr>
</tbody>
</table>

**Locomotives:**

In May 2004, the US EPA published the Clean Air Nonroad Diesel Rule, designed to dramatically reduce soot and emissions from construction, agricultural and industrial diesel-powered equipment. Locomotive and marine engines were exempted from certain engine modification requirements in the rule (the EPA later proposed a program specific to these

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5 U.S. Environmental Protection Agency, www.epa.gov/OMS/models/biodsl.htm

6 EPA's biodiesel emissions analysis program, http://www.epa.gov/OMS/models/biodsl.htm
Locomotive and marine diesel fuel was first reduced from uncontrolled levels to the low-sulfur diesel level of 500 parts per million (ppm) starting in June 2007, and the second step to ultra-low sulfur diesel (15 ppm cap) will go into effect in June 2012 (all other nonroad diesel engines must comply at the 15 ppm level in June 2010). The decreased lubricity of low-sulfur diesel could be an opportunity for the biodiesel industry to access this market. “Indications are that low concentrations of biodiesel might be sufficient to raise the lubricity to acceptable levels,” the EPA ruling reads. “Thus, we believe that biodiesel is a feasible technology that could help support today’s clean diesel fuel program.”

So far, few trains use biodiesel or renewable diesel, though there have been experiments in some passenger-train systems in Europe and US shortline railroads.

British Train Operating Company Virgin Trains in June of 2007 claimed to have run the world's first "biodiesel train", which was converted to run on a blended fuel which is 20% biodiesel processed from biological sources including rapeseed (Canola), soybean and palm oil. During a six-month trial, the train ran from Birmingham to Scotland, across South Wales, North East England, the North West, the West Country, the South West and the South coast. The experiment has been organized by Virgin Trains, the Association of Train Operating Companies and the Rail Safety and Standards Board.

On September 15, 2007, the Royal Train completed its first ever journey run on 100% biodiesel fuel supplied by Green Fuels Ltd. His Royal Highness, The Prince of Wales, and Green Fuels managing director, James Hygate, were the first passengers on a train fueled entirely by biodiesel fuel. Since 2007 the Royal Train has operated successfully on B100 (100% biodiesel).

Similarly, one of the first biodiesel tests on locomotives in the Northwest took place during the summer of 2008 when a state-owned short-line railroad (Eastern Washington Gateway Railroad) in Eastern Washington ran a test of a 25% biodiesel / 75% petroleum diesel blend, purchasing fuel from a biodiesel producer seated along the railroad tracks. The train will be powered by biodiesel made in part from canola grown in agricultural regions through which the short line runs.

Also in 2007, Disneyland began running their southern California amusement park trains on B98 biodiesel blends (98% biodiesel). The program was discontinued in 2008 due to storage issues, but in January 2009 it was announced that the park would then be running all trains on biodiesel.

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manufactured from its own used cooking oils. This is a change from running the trains on soy-based biodiesel.\textsuperscript{10}

In November 2009 the first cold weather use of biodiesel by a railroad in real world conditions will be used to power the Canadian cold-weather rail service, putting to test issues on the feasibility of using the fuel as biodiesel is known to have a slightly higher freezing point than standard diesel. The industry-leading pilot project is a partnership with Natural Resources Canada under the National Renewable Diesel Demonstration Initiative with the Northern American railway company Canadian Pacific. The project will be conducted under the National Renewable Diesel Demonstration Initiative which provides opportunities for real-world testing and performance evaluation ahead of Canadian regulatory action.

The five-month test cycle will see Canadian Pacific operating four General Electric AC4400 diesel locomotives with FDL-16 engines in captive service between Calgary and Edmonton. The company will conduct detailed mechanical examinations of the locomotives. The information gathered from the testing will be used to determine if a biodiesel mixture of five percent (B5) has any significant adverse effects on a locomotive in cold-climate operation. Effects on reliability, possible changes to the overhaul or maintenance work scope and reviews of specific components on the locomotives will also be monitored.

"Rail is already the most efficient means to move goods long-haul. This initiative positions Canadian Pacific to make a lasting impact by further reducing our network's environmental footprint," said Fred Green, Canadian Pacific’s president and chief executive. Apart from General Electric, Calgary-based fuel supplier 4Refuels is also cooperating with Canadian Pacific on the testing phase. Testing began in early November and will continue until the end of March 2010. The Canadian government plans to regulate an average five percent renewable fuel content based on the national gasoline pool by 2010. A requirement for an average two percent renewable content in diesel fuel and heating oil by 2011 or earlier is also being considered for implementation, subject to technical feasibility.\textsuperscript{11}

Presenting the proof that biodiesel works in rail applications seems to be a recurring theme. However, there are other issues that are unique to the rail industry, such as fuel supply (getting sufficient quantities in key fueling locations) and the unique nature of their engines. Rail engines are made using copper, which is more flexible than steel and can better handle the vibrations. Railroad companies must know how biodiesel reacts to the copper in these engines.

Proof will need to come from further field testing. Unlike the trucking industry—where a lot has been tested—in following the literature of the railroad industry there is limited information regarding commercial trials which highlights the importance of following the recent pilots mentioned above.
