Oregon Clean Fuels Program/Air Quality Division

HB 2186: Oregon Low Carbon Fuel Standards and Truck Efficiency

State of Oregon
Department of Environmental Quality

Submitted to:
Governor John Kitzhaber
Oregon Legislative Assembly
Oregon Environmental Quality Commission

By: Dick Pedersen, Director

March 2013

Air Quality Division
Oregon Clean Fuels Program
811 SW 6th Avenue
Portland, OR 97204
Phone: (503) 229-5696
(800) 452-4011
Fax: (503) 229-6762
Contact: Cory-Ann Wind
www.oregon.gov/DEQ

DEQ is a leader in restoring, maintaining and enhancing the quality of Oregon's air, land and water.

Last Updated: xx/xx/xx

This report prepared by:

Oregon Department of Environmental Quality
811 SW 6th Avenue
Portland, OR 97204
1-800-452-4011
www.oregon.gov/deq

Contact:
Cory-Ann Wind
(503) 229-5388

Alternative formats (Braille, large type) of this document can be made available.
Contact DEQ's Office of Communications & Outreach, Portland, at (503) 229-5696, or toll-free in Oregon at 1-800-452-4011, ext. 5696.

Table of Contents

Executive Summary 1
DEQ Staff Report to the Environmental Quality Commission 4
Final Adopted Rules 10
Summary of Public Comment and Agency Responses 45
Relationship to Federal Requirements 66
Land Use Evaluation Statement 69
Advisory Committee Process and Program Design 71
Economic Impact Analysis of the Low-Carbon Fuel Standard Rule 245
Letter from Governor Kitzhaber 375

Executive Summary

House Bill 2186 (2009), authorized the Environmental Quality Commission to adopt a low carbon fuel standards program for Oregon, and specified certain features, such as regulatory flexibility and consumer protection, to be included in the program design. This report summarizes DEQ's efforts to adopt rules for the program.

Key highlights of DEQ's report include: 1) Governor Kitzhaber's April 2012 letter directing DEQ to adopt the program in two phases - a tracking and reporting phase and the low carbon fuel standards phase; and 2) subsequent adoption of the first phase of the program by the Environmental Quality Commission in December 2012. This report also provides the status of other HB2186 strategies.

Low carbon fuel standards

The goal of Oregon's low carbon fuel standard is to reduce greenhouse gas emissions from petroleum transportation fuels by ten percent over a ten-year period. The program would provide Oregonians with more access to low cost fuels such as electricity, natural gas, propane, biogas and biofuels. The program also supports job growth by creating demand for construction of plants and infrastructure to produce and deliver these fuels. The program does not mandate the use of a specific alternative fuel or set a cap on total emissions. Compliance can be achieved using whichever combination of alternative fuels and credits is most cost effective for fuel providers.

Development of rules

DEQ developed proposed rules based on discussions and recommendations from a 29-member advisory committee that helped DEQ explore technical issues and policy choices for designing the Clean Fuels Program. The committee included representatives of many areas of expertise, including petroleum fuel, low carbon fuel, environment, labor, farm, construction, trucking and rail. DEQ's discussions with the committee included the design of consumer protections required under HB2186 in the form of exemptions and deferrals of program requirements in case fuel supply shortages or price increases were caused by the program.

As part of this advisory committee process, DEQ commissioned an economic analysis that assessed the costs and benefits of the program to Oregon's economy. The analysis found that the program would provide a net benefit to Oregon's economy in the form of increased job creation, gross state product and personal income, as well as decreased fuel expenditures.

In April 2012, Governor Kitzhaber directed DEQ to move forward with rulemaking and to implement the program in two separate phases. The first phase requires Oregon producers and importers of fuels to register with DEQ, keep records and submit reports about the fuels they currently supply. The second phase, if adopted at a later date, would require the same parties to meet the low carbon fuel standards by supplying cleaner fuels in Oregon or purchasing credits from clean fuel providers. The proposal called for implementing the first phase beginning January 1, 2013 and deferring implementation of the second phase pending further legislative action.

DEQ convened a second advisory committee to gather input on the fiscal impact of complying with the first phase of the program. Eleven people from the business and environmental communities were invited to participate on the committee and, with members of the public, were provided an opportunity to comment on the draft Statement of Need and Fiscal Impact. Comments were incorporated into the draft rules, which were put on public notice from July 20 through August 31, 2012.

EQC involvement

DEQ provided the EQC with briefings throughout the development of the program. On August 24, 2012, the EQC hosted a public hearing so that stakeholders could speak directly to the Commission. Sixteen representatives from the public, including fuel providers, clean fuels producers, environmental organizations and labor provided testimony.

Comments considered

DEQ received 102 written and oral comments during the public comment period. In general, those opposed to the program were concerned that businesses in Oregon would be at a competitive disadvantage due to uncertainty about adequate low carbon fuel supplies and infrastructure, as well as possible fuel price increases. Supporters of the program were concerned that further delay in implementing the rules would delay the environmental and economic benefits gained by the program. DEQ received valuable feedback from the public and stakeholders that improved the rules adopted for this rulemaking.

Rules adopted

After evaluating the comments received and the latest economic, policy, scientific and legal issues, DEQ decided to move forward with rules for just the first phase of the program – the registration, recordkeeping and reporting requirements. The second phase of the program – the requirements to reduce the average carbon intensity of fuels - will be discussed in more depth with the legislature before deciding whether to proceed with another rulemaking. On December 7, 2012, the EQC adopted final rules to require Oregon producers and importers of transportation fuels to register with DEQ, keep records and submit fuel reports to DEQ beginning in 2013.

Significant policy decisions

The advisory committee was tasked with providing input to DEQ on 19 policy issues including: the design of program safeguards to protect fuel consumers, the administrative procedures of how to collect and report accurate data, how to maximize flexibility for businesses to comply, and consideration of impacts that the program might have on Oregon's environment and economy. All of these discussions can be found in DEQs final committee report. Key policy choices proposed by DEQ in rule and adopted by the EQC include:

- Added propane as an opt-in fuel at the request of the propane industry;
- Established separate carbon intensity baseline values for conventional petroleum gasoline and diesel fuel;
- Established statewide carbon intensity values for electricity and conventional petroleum fuels;
- Added exemptions for fuel used in aircraft, racing activity vehicles, military tactical vehicles and tactical support equipment, railroad locomotives and ocean-going vessels;
- Developed a provision for a short-term emergency fuel supply deferral;
- Developed a provision for a forecasted fuel supply shortage deferral; and
- Developed a provision for a fuel price increase deferral.

The most significant policy decision made at this time was to delay adoption of rules for the second phase of the program. Initially, DEQ had proposed to adopt but indefinitely defer the second phase pending further legislative action and a second EQC rulemaking. Some stakeholders believed that adopting deferred phase 2 rules now was premature given the existence of the 2015 legislative sunset for the clean fuels program. DEQ removed the second phase rule language from its proposed rulemaking in order to provide a clearer immediate path forward for stakeholders. Further rulemaking for the next phase of the program is paused pending further discussions with the legislature.

Effects of 2015 sunset

Under HB 2186, the EQC's authority to implement the low carbon fuel standards sunsets on December 31, 2015. As required by the legislation, DEQ and the advisory committee discussed the likely effects of a program sunset. In the final report, DEQ concluded that the existence of the sunset is a significant barrier to new investment in the infrastructure needed to support the low carbon fuels standards. Removal of the sunset would provide a clear market signal to companies wishing to construct new clean fuel production capacity, purchase alternative fuel vehicles or install infrastructure to distribute clean fuels.

Next steps

Implementing the first phase of the program begins with Oregon fuel producers and importers registering with DEQ by June 30, 2013. DEQ estimates that approximately 70 companies will need to register the types of fuels and the carbon intensities of those fuels that they supply in Oregon. This requirement currently applies only to gasoline, diesel, ethanol and biodiesel. The first report summarizing this information is due on April 30, 2014 and every quarter after that. Also in 2013, the Legislature will be asked to remove the sunset date in HB2186.

Truck efficiency strategies for vehicles and engines – HB 2186 Sections 1 and 3

DEQ completed the truck efficiency and idling reduction study as required in Section 1 of HB 2186 during the 2009-2011 biennium. Based on the study, DEQ proposed legislation to improve truck efficiency and reduce idling in the 2011 session; DEQ's version of the bill did not pass.

Since 2009, DEQ's priority has been developing the low carbon fuel standards. DEQ will focus on the Section 3 measures as time allows in the 2013-2015 biennium.

Alternative Formats

Alternative formats of this document can be made available. Contact DEQ Office of Communications and Outreach for more information (503) 229-5696.

This page left intentionally blank.

State of Oregon
Department of Environmental Quality Memorandum

Date: Nov. 16, 2012

To: Environmental Quality Commission

From: Dick Pedersen, Director

Subject: Agenda item N, Action item, Rule proposal: Oregon Clean Fuels Program Dec. 6-7, 2012, EQC meeting

Why this is important

The Oregon Clean Fuels Program is a component of several important Oregon initiatives to reduce greenhouse gas emissions including Oregon's energy, transportation and climate protection action plans. Approximately one-third of Oregon's greenhouse gases come from transportation sources, and providing cleaner fuels will help reduce these emissions. This rulemaking provides the initial framework of the program that is foundational to eventual low carbon fuel standards.

DEQ recommendation and EQC motion

DEQ recommends that the Oregon Environmental Quality Commission adopt the proposed rules for the Oregon Clean Fuels Program, as provided in attachment A of this staff report.

Background and need for rulemaking

The 2009 Oregon Legislature authorized the Environmental Quality Commission to adopt low carbon fuel standards, with the goal to reduce greenhouse gas emissions from Oregon's transportation fuels. DEQ worked with stakeholders to develop the framework to implement the standards. In April 2012, Governor Kitzhaber asked DEQ to begin the rulemaking process to adopt the Oregon Clean Fuels Program.

Effect of rule

If adopted, the rules would create the first phase of the Oregon Clean Fuels Program.

The rules would require Oregon fuel producers and importers to register, keep records and report to DEQ the volumes and carbon intensities of the fuels they provide in Oregon. This would allow DEQ to gather valuable data about Oregon's transportation fuels that will help inform DEQ and decision makers about the feasibility of moving ahead with the next phase of the program. This is also intended to provide DEQ and regulated parties time to fully develop recordkeeping and reporting protocols and systems.

The next phase would require regulated parties to reduce the average carbon intensity of fuels they provide in Oregon each year, with the

ultimate goal of reducing greenhouse gas emissions by 10 percent from the 2010 levels. The Oregon Legislature will need to remove the statutory Dec. 31, 2015 sunset date to develop the next phase of the program. Then DEQ would propose new rules covering the next phase for the EQC to consider.

Commission authority

The commission has authority to take this action under Oregon Laws 2009, chapter 754, also referred to as House Bill 2186 (2009).

Key issues

At a previous commission meeting, DEQ discussed a proposal that entailed adopting rules for a two-phased program, with Phase 1 registration, recordkeeping and reporting to be implemented now and Phase 2, compliance with the standards, to be implemented at a later date. As initially proposed, implementation of the Phase 2 rules was deferred pending further approval by the Oregon Legislature and EQC.

During the comment period, many stakeholders said that they were concerned that the Clean Fuels Program would put Oregon businesses at a competitive disadvantage compared to businesses operating in other states without a similar program. Specifically, they cited unresolved legal issues in California, resources to implement the program, the potential economic impact of the program, and the legislative sunset date as reasons not to move forward with the program.

To allow time for resolution of these issues while providing a clear regulatory framework for the entire program, DEQ proposed to adopt the program in its entirety but indefinitely defer Phase 2. However, many stakeholders disagreed with this deferral approach and suggested waiting to adopt Phase 2 of the rules until after further discussions with the Oregon Legislature.

In light of the comments received, DEQ is proposing to modify its initial rule language to remove references to the second phase of the program, including language describing:

- Compliance with the declining annual average carbon intensity standards,
- The generation, banking and transfer of credits and deficits, and
- The deferral mechanisms for fuel shortages and fuel cost increases.

The revised proposal now focuses exclusively on implementing the registration, recordkeeping and reporting requirements. While Phase 2 is not proposed for adoption at this time, the model rule language for

Phase 2 will remain available for reference on DEQ's website.

The revised proposal allows DEQ to work with regulated and opt-in parties to build the reporting framework necessary for the success of the next phase of the program, while allowing time for additional discussion about the Phase 2 program design with stakeholders and the Oregon Legislature. This approach reinforces the regulatory flexibility focus of the authorizing statute.

In order to implement the registration, recordkeeping and reporting requirements of the first phase, the proposed rules include several other core administration features including:

- The designations of the regulated and opt-in parties for various fuels,
- The transfer and receipt of the compliance obligation,
- The process to propose and gain approval for a carbon intensity value, and
- The methodology to determine the amount of surpluses and shortfalls, previously called credits and deficits, and calculate net carbon balances.

DEQ will use these reports and other information to make a recommendation to the Oregon Legislature and EQC about the next phase of the program. DEQ remains committed to working with stakeholders and elected officials to continue developing the Oregon Clean Fuels Program.

Legal status of California's program

DEQ received comments that stakeholders are concerned that DEQ's proposal is unconstitutional based on legal proceedings occurring in California. Oregon's program is modeled after California's Low Carbon Fuel Standards, but contains several customizations for Oregon, many of them required by statute. In December 2011, a federal district court ruled that the California Low Carbon Fuel Standards impermissibly regulates interstate commerce. California appealed this ruling to the United States Circuit Court of Appeals for the Ninth Circuit, and the Ninth Circuit stayed the district court's ruling. This allows California to implement its standards while the Ninth Circuit considers whether to uphold or reverse the district court's ruling. A final ruling is expected in 2013.

DEQ is watching these developments closely and continues to analyze how it might affect Oregon's program. Because the first phase of its program does not raise the legal issues under contention in the

California lawsuit, Oregon may move forward with this phase prior to conclusion of the lawsuit. This allows Oregon to achieve the benefits of the program as soon as possible and to incorporate any program revisions required by the court in the design of the next phase.

Fee authority and the ability of DEQ to implement the program

DEQ received comments that stakeholders are concerned that DEQ lacks adequate resources to implement the program. At this time, there is no funding source to implement the Clean Fuels Program. DEQ has a small group of air quality planning staff that is funded to develop new air quality programs, including those to meet federal air quality standards, reduce risk from air toxics, reduce greenhouse gases and meet federal visibility protection requirements. DEQ was able to develop the Clean Fuels Program by temporarily assigning existing planning staff to this work and delaying other work. The planning staff must now turn to other challenges, such as addressing new National Ambient Air Quality Standards and reducing risk from air toxics exposures, and is not available to implement the Clean Fuels Program.

DEQ is proposing to introduce a legislative concept and policy option package for up to $475,000 for the 2013–2015 biennium and to request authority to charge a fee to regulated parties. If approved by the Oregon Legislature, the fee will be used to hire 1.3 new full-time-equivalent staff positions to implement the first phase of the program and assess the feasibility of moving to the next phase, including funds to hire outside expertise to assist the agency.

Scope of the fiscal and economic analysis

DEQ received comments that stakeholders are concerned that the scope of the fiscal and economic analysis conducted for this rulemaking was incorrect. As initially published for public comment, DEQ's proposal was divided into Phase 1 and Phase 2 of the program, with Phase 2 requirements deferred pending future EQC and legislative action.

DEQ convened a fiscal advisory committee to provide input on the Statement of Need and Fiscal and Economic Impact developed for this proposed rule. In it, costs for regulated parties to comply with Phase 1 were estimated for both initial start-up and ongoing maintenance. Since Phase 2 was deferred, no requirements were imposed; therefore, its fiscal and economic impact was zero.

Since the revised proposal is to include only the first phase of the program, the assumptions made in the initial Statement of Need and Fiscal and Economic Impact remain the same. If DEQ proposes rules for the next phase of the program, a Statement of Need and Fiscal and Economic Impact will be prepared at that time.

Sunset date in House Bill 2186

DEQ received comments that stakeholders feel that DEQ should not proceed with the program until the legislative sunset date is removed. House Bill 2186, approved in 2009, contains a sunset date of Dec. 31, 2015, and, unless the sunset is removed, the Clean Fuels Program cannot be implemented beyond that date. It would not be practical to establish and require compliance with the declining average carbon intensity standards and potentially have it end in 2015. Therefore, DEQ proposes to move forward with only the first phase of the program until after the sunset date is removed by the Oregon Legislature. If the sunset date is lifted, an additional rulemaking by EQC will be needed to adopt and implement the standards.

Public outreach

DEQ developed the rules based on discussions and recommendations from a 29-member advisory committee that helped DEQ explore technical issues and policy choices for designing the Oregon Clean Fuels Program. The committee included representatives of many areas of expertise, including petroleum fuel, low carbon fuel, environment, labor, farm, construction, trucking and rail.

DEQ also convened an advisory committee to gather input on the fiscal impact of complying with the requirements of the proposed rules. Eleven people from the business and environmental communities were invited to participate on the committee and, along with members of the public, were provided an opportunity to comment on the draft Statement of Need and Fiscal Impact.

Comments on the proposed rules were accepted from the public from July 20, 2012 through Aug. 31, 2012. A public hearing was hosted by the Oregon Environmental Quality Commission on Aug. 24, 2012, as part of the commission's meeting at DEQ's headquarters in downtown Portland. For that hearing, members of the public could also visit a DEQ regional office in Eugene, Medford, Bend or Pendleton for the opportunity to provide oral testimony via conference phone.

102 comments were received from the public, including 16 individuals who provided oral testimony at the public hearing. Oral and written comments are summarized in attachment C.

Next steps

If the rules are adopted, DEQ will file the rule record with the Oregon Secretary of State.

Oregon fuel producers and importers will be required to register with DEQ beginning on Jan. 1, 2013, but no later than June 30, 2013. They must submit documents showing, among other things, the volumes and

carbon intensities of the fuels they plan to provide in Oregon after July 1, 2013. Beginning on July 1, 2013, Oregon fuel producers and importers are required to begin keeping records for each fuel transaction. The first annual report, for the period of July 1 through Dec. 31, 2012, would be due to DEQ on April 30, 2014. The first quarterly report, for the period of Jan. 1 through March 31, 2014, would be due to DEQ on May 31, 2014.

DEQ intends to develop an electronic registration form and a web-based reporting tool for regulated parties to use in the first phase of the program. Since many of the regulated parties in Oregon also supply fuel in California, DEQ chose to collaborate with California to adapt and customize that state's registration and reporting tools for use in Oregon in order to streamline the recordkeeping and reporting processes.

DEQ intends to ask the 2013 Oregon Legislature to remove the sunset date from House Bill 2186. DEQ also intends to propose a legislative concept to the 2013 Oregon Legislature to request fee authority and a policy package to spend up to $475,000 for the 2013-2015 biennium.

Attachments

A. Proposed rules (redline)
B. Proposed rules (clean)
C. Summary of public comment and agency response
D. Presiding Officer's Report
E. Relationship to Federal Requirements questions
F. Statement of Need and Fiscal and Economic Impact
G. Land Use Evaluation Statement

Available upon request

1. House Bill 2186
2. Oregon Low Carbon Fuel Standards Advisory Committee Process and Program Design
3. Economic Impact Analysis of the Low-Carbon Fuel Standard Rule for the State of Oregon

Approved:

Division: _____

Section: _____

Report prepared by: Cory-Ann Wind

DEPARTMENT OF ENVIRONMENTAL QUALITY

DIVISION 253

OREGON CLEAN FUELS PROGRAM

340-253-0000

Overview

(1) **Context**. The Oregon Legislature has found that climate change poses a serious threat to the economic well-being, public health, natural resources and environment of Oregon, among other findings. Section 1, chapter 907, Oregon Laws 2007. The Oregon Clean Fuels Program will reduce Oregon's contribution to the global levels of greenhouse gas emissions and the impacts of those emissions in Oregon, in concert with other greenhouse gas reduction policies and actions by local governments, other states and the federal government.

(2) **Purpose**. The purpose of the Oregon Clean Fuels Program is to reduce the average amount of lifecycle greenhouse gas emissions per unit of fuel energy used in Oregon by a minimum of 10 percent below 2010 levels over a 10-year period.

(3) **Authority**. The 2009 Oregon Legislature adopted House Bill 2186, which was enacted as chapter 754 of Oregon Laws 2009, and authorizes the Environmental Quality Commission to adopt low carbon fuel standards for gasoline, diesel fuel and fuels used as substitutes for gasoline or diesel fuel. Sections 6 to 9 of chapter 754, Oregon Laws 2009 is printed as a note following ORS 468A.270 (2011 Edition). OAR Chapter 340 Division 253 implements section 6.

(4) **Flexible Implementation Approach**. This division requires regulated parties, and those parties that choose voluntarily to opt–in to the program, to register, keep records, report the carbon intensity of the fuel they produce or import for use in Oregon, and calculate surpluses and shortfalls against the baseline carbon intensity values. These values are based on the mix of regulated and opt-in fuels that were supplied in Oregon in 2010. While reporting of net carbon balance is required, regulated and opt-in parties are not required to balance surpluses and shortfalls at this time. This flexible implementation approach is designed to put in place only the administrative procedures necessary to implement the program. This approach is intended to minimize the initial costs to regulated parties by not requiring compliance with declining carbon intensity standards. DEQ will utilize the reports and other information to assess, at a minimum, the following factors to make a recommendation to the EQC about the next phase of the program:

(a) The cost and administrative burden of compliance for regulated and opt-in parties;

(b) The benefits of the program to Oregon's economy and environment;

(c) The current and projected availability of lower carbon fuels,

(d) The methodologies to provide exemptions and deferrals necessary to mitigate the cost of complying with the program, in accordance with Section 6(2)(d) of chapter 754, Oregon Laws 2009;

(e) The progress and adoption rates of cleaner fuels and vehicle technologies;

(f) The appropriate methods, based on the latest science, to establish baseline carbon intensity values and declining carbon intensity standards, including methodologies to incorporate land use change and other indirect effects;

(g) The latest information on the policies and legal issues regarding low carbon fuel standards;

(h) The status of federal and other state programs that address the carbon content of transportation fuel;

(i) The costs and administrative capacity of DEQ to implement the program; and

(j) The likely impact on all of the above elements, if declining average carbon intensity standards are implemented in the future.

(5) **Construction.** This division uses the following construction:

(a) OAR 340-253-#### followed by a bolded title is the number and title of the rule where:

(A) OAR is the acronym for *Oregon Administrative Rules*;

(B) 340 is the *chapter* number;

(C) 253 is the *division* number; and

(D) #### is the unique *rule* number.

(b) The subunits of a rule are within parenthesis in the following order:

(A) *Section*. The section is a Hindu-Arabic numeral expressed in sequence as (1), (2), (3) and so forth. Each section has a bold title;

(B) *Subsection.* The subsection is a lowercase English alphabet character expressed in sequence as (a), (b), (c) and so forth;

(C) *Paragraph*. The paragraph is an uppercase English alphabet character expressed

in sequence as (A), (B), (C) and so forth; and

(D) *Subparagraph*. The subparagraph is a lowercase Roman numeral expressed in sequence as (i), (ii), (iii) and so forth.

(c) A reference prefaced with the word *section*, *subsection*, *paragraph* or *subparagraph* is a reference to a subunit within the same rule; and

(d) A reference prefaced with OAR 340-253 is a reference to another rule under the Oregon standards.

(6) **LRAPA**. Notwithstanding 340-200-0010(3), the DEQ administers this division in all areas of the State of Oregon.

Stat. Auth.: ORS 468.020 and section 6, chapter 754, Oregon Laws 2009, which is printed as a note following ORS 468A.270 (2011 Edition).
Stats. Implemented: Section 6, chapter 754, Oregon Laws 2009, which is printed as a note following ORS 468A.270 (2011 Edition).
History must be added at the time of rule adoption.
This language must be added at the end of each rule at the time of rule adoption.

340-253-0040

Definitions

The definitions in OAR 340-200-0020 and this rule apply to this division. If the same term is defined in this rule and OAR 340-200-0020, the definition in this rule applies to this division.

(1) "**Actual PADD 5**" means Petroleum Administration for Defense District 5, which includes Oregon, Washington, Arizona, Nevada, Hawaii, California and Alaska.

(2) "**Baseline carbon intensity value**" is 90.38 gCO2e per MJ for gasoline and gasoline substitutes and 90.00 gCO2e per MJ for diesel fuel and diesel substitutes. These values are based on the mix of regulated and opt-in fuels supplied for use as a transportation fuel in Oregon in 2010.

(3) "**Biodiesel**" has the same meaning as defined under OAR 603-027-0410.

(4) "**Biogas**" means natural gas that meets the purity requirements under OAR 860-023-0025 and is produced from the breakdown of organic material in the absence of oxygen. Biogas production processes include, but are not limited to, anaerobic digestion, anaerobic decomposition and thermo-chemical decomposition:

(a) Applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, and waste from energy crops; and

(b) Used to produce landfill gas and digester gas.

(5) "**Biogas compressed natural gas**" means compressed natural gas consisting solely of compressed biogas.

(6) "**Biogas liquefied natural gas**" means liquefied natural gas consisting solely of liquefied biogas.

(7) **"Biomass**" has the same meaning as defined under OAR 603-027-0410.

(8) "**Biomass-Based diesel**" has the same meaning as defined under OAR 603-027-0410.

(9) "**Blendstock**" means a component used alone or blended with one or more other components to produce a finished fuel used in a motor vehicle.

(10) "**Carbon intensity**" means the amount of lifecycle greenhouse gas emissions per unit of energy of fuel expressed in grams of carbon dioxide equivalent per megajoule (gCO2e per MJ).

(11) "**Compressed natural gas**" means either biogas or fossil natural gas that meets the standards listed under OAR 860-023-0025 compressed to a pressure greater than ambient

pressure.

(12) **"Diesel fuel**" has the same meaning as defined under OAR 603-027-0410.

(13) "**Diesel substitute**" means any fuel, other than diesel fuel, that may be used in light-duty or heavy-duty vehicles, and off-road vehicles that typically use diesel as a fuel. Diesel substitutes include but are not limited to liquefied natural gas used in a heavy duty motor vehicle and biodiesel used in a heavy duty motor vehicle.

(14) "**Electricity bundled services supplier**" means any person or entity that provides charging infrastructure and provides access to vehicles charging under contract with a charging service recipient or charging equipment owner.

(15) "**Electric utility**" has the same meaning as defined in ORS 757.600.

(16) "**Ethanol**," or "**Denatured fuel ethanol**" has the same meaning as defined under OAR 603-027-0410.

(17) "**Feedstock**" means the material a fuel is made from.

(18) "**Finished fuel**" means a transportation fuel used directly in a motor vehicle without additional chemical or physical processing.

(19) "**Finished hydrogen fuel**" means a finished fuel that consists of:

(a) Hydrogen; or

(b) A blend of hydrogen and another fuel.

(20) "**Fossil compressed natural gas**" means compressed natural gas derived solely from petroleum or fossil sources such as oil fields and coal beds.

(21) "**Fossil liquefied natural gas**" means liquefied natural gas derived solely from petroleum or fossil sources such as oil fields and coal beds.

(22) "**Fuel type**" means any unique fuel feedstock and production process combination.

(23) "**Gasoline**" has the same meaning as defined under OAR 603-027-0410.

(24) "**Gasoline substitute**" means any fuel, other than gasoline, that may be used in light-duty vehicles that typically use gasoline as a fuel. Gasoline substitutes include but are not limited to electricity used in a light-duty motor vehicle and natural gas used in a light-duty motor vehicle.

(25) "**Heavy duty motor vehicle**" has the same meaning as defined under OAR 340-256-0010.

(26) "**Import**" means to bring a product from outside Oregon into Oregon.

(27) "**Importer**" means the person who owns a product imported from outside Oregon into Oregon:

(a) With respect to any imported liquid product, it means the person who owns the fuel in the stationary storage tank into which the product was first transferred after it was imported into Oregon; or

(b) With respect to any biogas, it means the person who owns the imported product upon receipt at a pipeline in Oregon through which the biogas is delivered in Oregon.

(28) "**Large Oregon importer**" means any person who imports more than 250,000 gallons of fuel in a given calendar year into Oregon.

(29) "**Light-duty motor vehicle**" has the same meaning as defined under OAR 340-256-0010.

(30) "**Lifecycle greenhouse gas emissions**" means the:

(a) Aggregate quantity of greenhouse gas emissions including direct and significant indirect emissions, such as significant emissions from changes in land use associated with the fuels;

(b) Full fuel lifecycle including all stages of fuel production, from feedstock generation or extraction, production, distribution, and combustion of the finished fuel by the consumer; and

(c) Mass values for all greenhouse gases as adjusted to account for their relative global warming potential.

(31) "**Liquefied natural gas**" means biogas or fossil natural gas converted to liquid form.

(32) "**Liquefied petroleum gas**" or "**propane**" has the same meaning as defined under OAR 603-027-0395.

(33) "**Motor vehicles**" has the same meaning as defined under OAR 603-027-0410.

(34) "**Natural gas**" means a mixture of gaseous hydrocarbons and other compounds from either fossil or biogas sources, with at least 80 percent methane by volume, and typically sold or distributed by utilities such as any utility company regulated by the Oregon Public Utility Commission.

(35) "**Opt-in party**" means a person who is not a regulated party and who elects to register with DEQ under OAR 340-253-0100(4).

(36) "**Oregon producer**" means:

(a) With respect to any liquid blendstock or finished fuel, the person who makes the liquid blendstock or finished fuel at the Oregon production facility; or

(b) With respect to any biogas produced in Oregon, the person who refines the gas to pipeline quality.

(37) "**Oregon production facility**" means a facility located in Oregon that:

(a) Produces any liquid blendstock or finished fuel other than liquefied natural gas; or

(b) Converts, compresses, liquefies, refines, treats or otherwise processes natural gas into compressed natural gas or liquefied natural gas that is ready for use as a transportation fuel in a motor vehicle without further physical or chemical processing.

(38) "**OR-GREET**" means the Greenhouse gases, Regulated Emissions, and Energy in Transportation (GREET) Argonne National Laboratory model modified and maintained for Oregon. Copies of OR-GREET are available from DEQ upon request.

(39) "**Private access fueling facility**" means an Oregon fueling facility that restricts access by use of a card or key-activated fuel dispensing device to dispensing fuel to nonretail customers.

(40) "**Product transfer document**" means an invoice, bill of lading, purchase contract, or any other proof of fuel ownership transfer.

(41) "**Public access fueling facility**" means an Oregon fueling facility that is not a private access fueling facility.

(42) "**Regulated party**" means a person identified as a regulated party under OAR 340-253-0310 through 340-253-0340. Regulated parties must comply with the requirements under OAR 340-253-0100.

(43) "**Shortfall(s)**" means a state in which the carbon intensity of a fuel is <u>higher</u> than the baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes. Shortfalls are expressed in units of metric tons of carbon dioxide equivalent (CO2e) and are calculated under OAR 340-253-1020.

(44) "**Small Oregon importer**" means any person who imports 250,000 gallons or less of fuel in a given calendar year into Oregon.

(45) "**Statutory PADD 5**" means a portion of Petroleum Administration for Defense District 5, which includes Oregon, Washington, Arizona and Nevada.

(46) "**Surplus(es)**" means a state in which the carbon intensity of a fuel is <u>lower</u> than the baseline carbon intensity value for gasoline or diesel fuel and their substitutes. Surpluses are

expressed in units of metric tons of carbon dioxide equivalent (CO2e) and are calculated under OAR 340-253-1020.

(47) "**Transportation fuel**" means any fuel used or intended for use in motor vehicles as defined under OAR 603-027-0410.

340-253-0060

Acronyms

The following acronyms apply to this division:

(1) "ASTM" means ASTM International (formerly American Society for Testing and Materials).

(2) "BTU" means British thermal unit.

(3) "DEQ" means Oregon Department of Environmental Quality.

(4) "EQC" means Oregon Environmental Quality Commission.

(5) "gCO2e" means grams of carbon dioxide equivalent.

(6) "gge" means gasoline gallon equivalents.

(7) "MJ" means megajoule.

340-253-0100

Oregon Clean Fuels Program

(1) **Applicability.**

(a) All regulated parties under section (3) that import or produce, sell, supply or offer for sale in Oregon any regulated fuel, as defined under OAR 340-253-0200, are subject to this rule.

(b) Any person may become an opt-in party by registering with DEQ under section (4) of this rule. All opt-in parties under section (3) that import or produce, sell, supply or offer for sale in Oregon any opt-in fuel, as defined under OAR 340-253-0200, are subject to this rule.

(2) **Requirements.** Beginning January 1, 2013:

(a) Regulated and opt-in parties, except for small Oregon importers, must register under section (4) of this rule, keep records under section (5) of this rule, and submit reports under sections (6) and (7) of this rule; and

(b) Small Oregon importers must register under section (4) of this rule and are exempt from keeping records under section (5) of this rule and submitting reports under sections (6) and (7) of this rule.

(3) **Regulated party or opt-in party.** The following rules designate regulated and opt-in parties, by type of fuel:

(a) OAR 340-253-0310 for gasoline, diesel fuel, biodiesel, biomass-based diesel, ethanol, and any other liquid fuel except liquefied natural gas and liquefied petroleum gas;

(b) OAR 340-253-0320 for natural gas including compressed natural gas, liquefied natural gas, biogas and liquefied petroleum gas;

(c) OAR 340-253-0330 for electricity; and

(d) OAR 340-253-0340 for hydrogen fuel or a hydrogen blend.

(4) **Registration.**

(a) After January 1, 2013, but no later than June 30, 2013, each regulated party must submit a complete application under OAR 340-253-0500 to register with DEQ for each fuel type the party imports or produces, sells, supplies or offers for sale in Oregon on or before July 1, 2013, and that it plans to continue to import or produce, sell, supply or offer for sale in Oregon after July 1, 2013.

(b) Beginning on July 1, 2013, each regulated party must submit a complete application

under OAR 340-253-0500 to register with DEQ for each fuel type, on or before the date upon which it begins to import or produce, sell, supply or offer for sale in Oregon such fuel.

(c) To become an opt-in party a person must submit a complete application under OAR 340-253-0500 to register with DEQ.

(5) **Records**.

(a) Beginning on July 1, 2013, each regulated party must develop and retain all records required under OAR 340-253-0600.

(b) Beginning on the latter of either July 1, 2013, or the date that an opt-in party submits a complete application, as determined by DEQ, under subsection (4)(c) of this rule, each opt-in party must develop and retain all records required under OAR 340-253-0600.

(6) **Quarterly report**. Beginning on January 1, 2014, each regulated and opt-in party must submit quarterly reports under OAR 340-253-0630. Reports must be submitted to DEQ for:

(a) January through March of each year, by May 31;

(b) April through June of each year, by August 31;

(c) July through September of each year, by November 30; and

(d) October through December of each year, by February 28 of the following year.

(7) **Annual report.** Each regulated party and opt-in party must submit an annual report each year under OAR 340-253-0650. The report must be submitted to DEQ by April 30 of each year to report for the prior calendar year; except for 2013, when the reporting period is from July 1 through December 31.

340-253-0200

Regulated and Opt-in Fuels

(1) **Applicability**. The transportation fuels listed in this rule are subject to Division 253, unless exempt under OAR 340-253-0250.

(2) **Regulated fuels.** Regulated fuels means the following transportation fuels or blendstocks:

(a) Gasoline;

(b) Diesel fuel;

(c) Fossil liquefied natural gas that is imported, but not transferred by a natural gas pipeline in Oregon;

(d) A fuel blend containing ethanol;

(e) A fuel blend containing biomass-based diesel or biodiesel;

(f) Ethanol or denatured ethanol, also referred to as E100;

(g) Neat biomass-based diesel and biodiesel, also referred to as B100; and

(h) Any other liquid or non-liquid fuel not listed in section (3) or exempted under OAR 340-253-0250.

(3) **Opt-in fuels.** Opt-in fuels means the following transportation fuels:

(a) Electricity;

(b) Hydrogen fuel;

(c) Hydrogen blends;

(d) Fossil compressed natural gas;

(e) Fossil liquefied natural gas derived from fuel delivered through a natural gas pipeline;

(f) Biogas compressed natural gas;

(g) Biogas liquefied natural gas; and

(h) Liquefied petroleum gas.

340-253-0250

Exempt Fuels and Fuel Uses

(1) **Exempt fuels**. The following fuels are exempt from the definition of regulated fuels under OAR 340-253-0200(2)(h):

(a) A fuel sold, supplied or offered for sale in Oregon if all providers supply an aggregate volume of less than 360,000 gge per year in Oregon. The party must:

(A) Demonstrate that the exemption applies; and

(B) Obtain exemption approval from DEQ in writing.

(b) A fuel produced from a research, development or demonstration facility as defined under OAR 330-090-0110 if the annual production volume is either 10,000 gallons or less or no more than 50,000 gallons and the fuel producer uses the entire volume for its own motor vehicles. The party must:

(A) Demonstrate that the exemption applies; and

(B) Obtain exemption approval from DEQ in writing.

(2) **Exempt fuels based on fuel uses.** Fuels are exempt from the definition of regulated fuels under OAR 340-253-0200(2)(h) if:

(a) The fuel is sold, supplied or offered for sale for use in the following motor vehicles:

(A) Aircraft;

(B) Racing activity vehicles under ORS 801.404;

(C) Military tactical vehicles and tactical support equipment;

(D) Railroad locomotives;

(E) Ocean-going vessels defined under OAR 856-010-0003, except for vessel under fishery or recreational endorsement under title 46 United States Code, chapter 121;

(F) Motor vehicles registered as farm vehicles under ORS 805.300;

(G) Farm tractors, as defined under ORS 801.265;

(H) Implements of husbandry, as defined under ORS 801.310; or

(I) Motor trucks, as defined under ORS 801.355, used primarily to transport logs; and

(b) The regulated or opt-in party documents that the fuel was sold, supplied or offered for sale for use in a motor vehicle listed in subsection (a), as required under OAR 340-253-0600. Documentation that the fuel was transferred through a dedicated source to one of the motor vehicles identified in subsection (a) is sufficient. If not transferred through a dedicated source, all documentation must be on an individual fuel transaction basis.

(3) Fuel possession. Any fuel user or seller may possess any fuel regardless of its carbon intensity value, including but not limited to owners of the motor vehicles listed under subsection (2)(a).

Designation of Regulated and Opt-in Parties

340-253-0310

Regulated Parties for Gasoline, Diesel Fuel, Biodiesel, Biomass-based Diesel and Ethanol and Other Regulated Fuels Except for Liquefied Natural Gas

(1) **Applicability.** This rule applies to all liquid blendstocks and liquid finished fuels listed under OAR 340-253-0200(2) except liquefied natural gas**.**

(2) **Initial regulated party.** The initial regulated party is the Oregon producer, large Oregon importer or small Oregon importer of the fuel.

(3) **Recipient notification requirement.** Before actual fuel ownership is transferred from one party to another, the recipient of the fuel must notify the transferor of the fuel whether or not the recipient is an Oregon producer, a large Oregon importer, or a small Oregon importer.

(4) **Regulated party options and responsibilities for transfers if the recipient is an Oregon producer or large Oregon importer.** If the initial regulated party transfers fuel to an Oregon producer or a large Oregon importer, then the transferor and the recipient have the options and responsibilities under this section.

(a) Unless the transferor elects to remain the regulated party under (4)(b):

(A) The recipient is now the regulated party who:

(i) Must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel; and

(ii) Is responsible for surplus and shortfall calculations under OAR 340-253-1020.

(B) The transferor must provide the recipient a product transfer document by the time of transfer. The product transfer document must prominently indicate:

(i) The recipient is now the regulated party who must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel; and

(ii) The information required under OAR 340-253-0600.

(C) The transferor is no longer required to comply with the recordkeeping and

reporting requirements under OAR 340-253-0100 for the fuel, except for maintaining the product transfer documentation under OAR 340-253-0600.

(b) The transferor and recipient may agree in writing for the transferor to remain the regulated party for the fuel, by the time fuel ownership is transferred. If the transferor elects to remain the regulated party:

(A) The transferor:

(i) Must provide the recipient a product transfer document at the time of transfer that prominently indicates that the transferor elects to remain the regulated party for the fuel;

(ii) The transferor must comply with the recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel; and

(iii) The transferor is responsible for surplus and shortfall calculations under OAR 340-253-1020; and

(B) The recipient must maintain the product transfer documentation under OAR 340-253-0600.

(5) **Regulated party options and responsibilities for transfers if the recipient is a small Oregon importer or is not an importer and is not an Oregon producer.** If the initial regulated party transfers fuel to a small Oregon importer or a person who is not an importer and not an Oregon producer, then the transferor and the recipient have the options and responsibilities under this section.

(a) The transferor remains the regulated party unless the transferor and the recipient agree that the recipient is the regulated or opt-in party under (b), who:

(A) Must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel; and

(B) Is responsible for surplus and shortfall calculations under OAR 340-253-1020.

(b) The transferor and recipient may agree in writing for the recipient to become the regulated party for the fuel, by the time fuel ownership is transferred. If the recipient elects to become the regulated party:

(A) The transferor must:

(i) Provide the recipient a product transfer document at the time of transfer that prominently indicates that the recipient elects to become the regulated party for the fuel; and

(ii) Maintain the product transfer documentation under OAR 340-253-0600.

(B) The recipient:

(i) Must comply with the recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel;

(ii) Must maintain the product transfer documentation under OAR 340-253-0600; and

(iii) Is responsible for surplus and shortfall calculations under OAR 340-253-1020.

340-253-0320

Regulated Parties and Opt-in Parties for Compressed Natural Gas, Biogas, Liquefied Natural Gas and Liquefied Petroleum Gas

(1) **Fossil compressed natural gas.** For fossil compressed natural gas, the opt-in party is the owner of the fueling equipment at the facility where the fossil compressed natural gas is dispensed for use in motor vehicles.

(2) **Biogas compressed natural gas**. For biogas compressed natural gas that is dispensed directly into motor vehicles in Oregon without first being blended with fossil compressed natural gas, the initial opt-in party is the Oregon producer or importer of the biogas.

(3) **Fossil liquefied natural gas.** For fossil liquefied natural gas:

(a) For fuel that is a regulated fuel under OAR 340-253-0200(2)(c), the initial regulated party is the owner of the liquefied natural gas when it is transferred to the facility where the liquefied natural gas is dispensed for use into motor vehicles; or

(b) For fuel that is an opt-in fuel under OAR 340-253-0200(3)(e), the initial opt-in party is the owner of the liquefied natural gas when it is transferred to the facility where the liquefied natural gas is dispensed for use into motor vehicles.

(4) **Biogas liquefied natural gas**. For biogas liquefied natural gas that is dispensed directly into motor vehicles in Oregon without first being blended with fossil liquefied natural gas, the initial opt-in party is the Oregon producer or importer of the biogas liquefied natural gas.

(5) **Biogas compressed natural gas added to fossil compressed natural gas**. For blends of these fuels, the opt-in parties for each of the component fuel types of the blended fuel remains the same as provide in sections (1) through (4).

(6) **Biogas liquefied natural gas added to fossil liquefied natural gas.** For blends of these fuels, the regulated and opt-in parties for each of the component fuel types of the blended

fuel remains the same as provide in sections (1) through (4).

(7) **Liquefied petroleum gas.** For liquefied petroleum gas, the opt-in party is the owner of the fueling equipment at the facility where the liquefied petroleum gas is dispensed for use into motor vehicles.

(8) **Regulated and opt-in party options and responsibilities for transfers of compressed natural gas, biogas, liquefied natural gas and liquefied petroleum gas.** The transferor and the recipient have the following options and responsibilities under this section whenever the initial regulated or opt-in party transfers ownership of the fuel.

(a) The transferor remains the regulated or opt-in party unless the transferor and the recipient agree that the recipient is the regulated or opt-in party under (b), who:

(A) Must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel;

(B) Is responsible for surplus and shortfall calculations under OAR 340-253-1020; and

(C) May generate surpluses under OAR 340-253-1000(4).

(b) The transferor and recipient may agree in writing for the recipient to become the regulated or opt-in party for the fuel, by the time fuel ownership is transferred.

(A) The product transfer document must clearly indicate that the recipient is now the regulated or opt-in party who must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel;

(B) The recipient:

(i) Is responsible for surplus and shortfall calculations under OAR 340-253-1020; and

(ii) May generate surpluses under OAR 340-253-1000(4).

(C) The transferor is no longer required to comply with the recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel, except for maintaining the product transfer documentation under OAR 340-253-0600.

340-253-0330

Opt-in Parties for Electricity

(1) **Opt-in party priority and deadlines.** Sections (2) through (4) determine the opt-in party who may generate surpluses under OAR 340-253-1000(4) for electricity used as a

transportation fuel.

(2) **Electricity bundled services supplier.** The electricity bundled services supplier must opt in by submitting a complete application to register with DEQ under OAR 340-253-0500 by September 1 of the year prior to the calendar year in which the surpluses will be generated if the electricity bundled services supplier elects to generate surpluses. Upon submitting a complete application, the electricity bundled services supplier becomes the opt-in party until it opts out under OAR 340-253-0500.

(3) **Electric Utility.** The electric utility may opt in by submitting a complete application to register with DEQ under OAR 340-253-0500 by November 1 of the year prior to the calendar year in which the surpluses will be generated, if the electricity bundled services supplier under section (2) does not opt-in. Upon submitting a complete application, the electric utility becomes the opt-in party for the following calendar year.

(4) **Owner or operator of electric-charging equipment.** The owner or operator of electric-charging equipment, including residential charging equipment, may opt in by submitting a complete application to register with DEQ under OAR 340-253-0500 by December 1 of the year prior to the calendar year in which the surpluses will be generated, if the electricity bundled services supplier under section (2) and the electric utility under section (3) do not opt-in. Upon submitting a complete application, the owner or operator of electric-charging equipment becomes the opt-in party for the following calendar year.

340-253-0340

Opt-in Parties for Hydrogen Fuel or Hydrogen Blends

(1) **Initial opt-in party.** The initial opt-in party for a volume of finished hydrogen fuel is the Oregon producer or Oregon importer of the finished hydrogen fuel.

(2) **Opt-in party options and responsibilities for transfers.** The transferor and the recipient have the following options and responsibilities whenever the initial opt-in party transfers ownership of the finished hydrogen fuel:

(a) The transferor remains the opt-in party unless the transferor and the recipient agree that the recipient is the opt-in party under (b), who:

(A) Must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel;

(B) Is responsible for surplus and shortfall calculations under OAR 340-253-1020; and

(C) May generate surpluses under OAR 340-253-1000(4).

(b) The transferor and recipient may agree in writing for the recipient to be the opt-in party for the fuel, by the time fuel ownership is transferred.

(A) The product transfer document must clearly indicate that the recipient is now the opt-in party who must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel.

(B) The recipient:

(i) Must comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel;

(ii) Is responsible for surplus and shortfall calculations under OAR 340-253-1020; and

(iii) May generate surpluses under OAR 340-253-1000(4).

(C) The transferor is no longer required to comply with the registration, recordkeeping and reporting requirements under OAR 340-253-0100 for the fuel, except for maintaining the product transfer documentation under OAR 340-253-0600.

340-253-0400

Fuel Carbon Intensity Values

(1) **Statewide carbon intensity values.**

(a) A regulated or opt-in party must use the statewide average carbon intensity value in Table 1 or 2 under OAR 340-253-3010 or -3020, as applicable, for the following fuels:

(A) Gasoline;

(B) Diesel fuel;

(C) Compressed fossil natural gas derived from natural gas not imported to North America in liquefied form;

(D) Liquefied petroleum gas; and

(E) Electricity, unless an electricity provider meets the conditions under subsection (1)(b) and proposes a different carbon intensity value.

(b) The opt-in party for electricity may propose a carbon intensity value different from the statewide average carbon intensity value if the electricity provider:

(A) Only provides electricity for transportation; and

(B) Is exempt from the definition of public utility under ORS 757.005 (1)(b)(G), and is not regulated by the Oregon Public Utility Commission.

(c) Every three years, DEQ must review the statewide average carbon intensity values in Table 1 or 2 under OAR 340-253-3010 or -3020 and must:

(A) Consider the crude oil and other energy sources, production processes and flaring rates and other considerations that might affect the lifecycle carbon intensity of fuel used in Oregon; and

(B) Propose the EQC revise and update statewide average carbon intensity values in Table 1 or 2 under OAR 340-253-3010 or -3020 if DEQ determines that values should be changed by more than 5 gCO2e per MJ or 10 percent.

(2) **Carbon intensity values for established pathways.** Except as provided in section (3), regulated and opt-in parties must use the carbon intensity values for ethanol, biodiesel, biomass-based diesel, liquefied natural gas, biogas compressed natural gas, biogas liquefied natural gas, hydrogen, liquefied petroleum gas and any fossil compressed natural gas produced from natural gas that arrives in North America in liquefied form that best matches each fuel's carbon intensity, as listed in Table 1 or 2 under OAR 340-253-3010 or -3020, as applicable.

(3) **Individual carbon intensity values.**

(a) **Directed by DEQ.** A regulated or opt-in party must obtain an individual carbon intensity value for a fuel, if DEQ:

(A) Determines the fuel's carbon intensity is not adequately represented by any of the carbon intensity values for established pathways in Table 1 or 2 under OAR 340-253-3010 or -3020; and

(B) Directs the regulated or opt-in party to obtain an individual carbon intensity value under OAR 340-253-0450.

(b) **Election of the party.** A regulated or opt-in party may propose an individual carbon intensity value for a fuel if:

(A) The fuel's carbon intensity, when compared to the carbon intensity value for the most similar fuel type in Table 1 or 2 under OAR 340-253-3010 or -3020, as applicable, changes by at least 5.0 gCO2e per MJ or 10 percent;

(B) The party has the capacity and intent to provide more than one million gge per year of the fuel in Oregon unless all providers of that fuel type supply less than one million gge per year in total; and

(C) The party applies for and obtains DEQ approval under OAR 340-253-0450.

(c) **New fuel or feedstock.** A regulated or opt-in party must obtain approval for an individual carbon intensity value under OAR 340-253-0450 for any fuel not included in Table 1 or 2 under OAR 340-253-3010 or -3020 and for any fuel made from a feedstock not represented in a carbon intensity value in Table 1 or 2 under OAR 340-253-3010 or -3020. The party must submit a modification to the original registration under OAR 340-253-0500(5) within 30 days,

(d) **Process change notification**. The regulated or opt-in party must notify DEQ and obtain approval for an individual carbon intensity value under OAR 340-253-0450 for any changes to the fuel production process, if the fuel's carbon intensity value changes by more than 5.0 gCO2e per MJ or 10 percent. The party must submit a modification to the original registration under OAR 340-253-0500(5) within 30 days.

(4) **OR-GREET.** The regulated or opt-in party must calculate all carbon intensity values using the approved version of OR-GREET, or a DEQ-approved comparable model for any fuel that cannot be modeled with OR-GREET. Any variations from the approved version of OR-GREET must be documented as described under OAR 340-253-0450(1) and submitted to DEQ for approval.

(5) **Calculation requirements**. When a regulated or opt-in party calculates a carbon intensity

value of:

(a) Fuels made from biomass feedstock, the party may assume that the combustion and growing components of the fuel's lifecycle greenhouse gas emissions have net zero lifecycle carbon dioxide emissions.

(b) Fuels made from petroleum feedstock, including waste petroleum feedstock, the party may not assume that the combustion of the fuel has net zero carbon dioxide emissions.

(c) Fuels made from waste feedstock, the party may assume that the lifecycle greenhouse gas emissions analysis of the carbon intensity value begins when the original product becomes waste.

340-253-0450

Approval for Individual Carbon Intensity Values

(1) **Individual carbon intensity value approval**. The regulated or opt-in party may not use an individual carbon intensity value without written DEQ approval under this rule. Individual carbon intensity values are not available for the fuels listed under OAR 340-253-0400(1)(a).

(a) **OR-GREET input modifications.** The regulated or opt-in party may propose a modification to inputs into the OR-GREET model that more accurately reflect the specific carbon intensity of the fuel.

(b) **OR-GREET model modifications.** The regulated or opt-in party may propose modifications to the OR-GREET model. The proposal for an individual carbon intensity value must include:

(A) Inputs used to generate the carbon intensity values under OAR 340-253-0400; and

(B) All modified parameters used to generate the new fuel carbon intensity value.

(c) **Non-OR-GREET modifications**. The regulated or opt-in party may propose modifications based on any lifecycle assessment model other than OR-GREET. The proposal for an individual carbon intensity value must include:

(A) Inputs used to generate the carbon intensity values under OAR 340-253-0400; and

(B) All parameters used to generate the new fuel carbon intensity value.

(2) **Reliability.** The regulated or opt-in party must supply documentation necessary for DEQ to determine that the method used to calculate the individual carbon intensity value under section (1) is reliable and at least comparable to the approved version of OR-GREET.

(3) **Modification submittal.** The regulated or opt-in party must submit all documentation for the proposed modifications under this rule including all:

(a) Supporting data;

(b) Calculations;

(c) Flow diagrams;

(d) Equipment description;

(e) Maps; and

(f) Any other information DEQ may need to verify the fuel type and the method for calculating the proposed individual carbon intensity value.

(4) **Review process**. DEQ must determine whether the proposal is complete within 15 workdays after receipt of any modification submitted under section (3):

(a) If DEQ determines the proposal is incomplete, DEQ must notify the regulated or opt-in party and identify the deficiencies. DEQ has 15 workdays to determine if the supplemental submittal is complete, or to notify the party and identify the continued deficiencies.

(b) If DEQ determines the proposal is complete, DEQ must:

(A) Publish the application on the Oregon Clean Fuels Program website; and

(B) Approve or deny an individual carbon intensity value under section (5) or (6).

(5) **DEQ approval**. A regulated or opt-in party may use an individual carbon intensity value upon receiving written approval from DEQ. DEQ will propose to incorporate all associated parameters and fuel-related information of a DEQ-approved individual carbon intensity value into Table 1 or 2 under OAR 340-253-3010 or -3020, as applicable, in a future rulemaking.

(6) **DEQ denial**. If DEQ determines the proposal for an individual carbon intensity value is not complete or adequately documented to establish its reliability, DEQ must deny the modification proposal, notify the party which carbon intensity value to use and identify the basis for the denial.

340-253-0500

Registration

(1) **Registration information**. To register, a regulated or opt-in party must submit the following to DEQ:

(a) Company identification, including a physical and mailing address, phone number, e-mail address and a contact name.

(b) The fuel type(s) that will be sold, supplied or offered for sale in Oregon.

(c) The producer of the fuel, including its physical address and a contact name, for each fuel type.

(d) The regulated or opt-in party's proposed carbon intensity value for each fuel type. The proposed carbon intensity value must be:

(A) A statewide carbon intensity value for any fuel listed under OAR 340-253-0400(1);

(B) An individual carbon intensity value listed in Table 1 or 2 under OAR 340-253-3010 or -3020; or

(C) A proposal to obtain a new individual carbon intensity value under OAR 340-253-0450.

(e) Other information requested by DEQ related to registration.

(2) **Completeness of submittal.** DEQ must review the information submitted under section (1) to determine if the submission is complete.

(a) If DEQ determines the submission is incomplete, DEQ must notify the party of the information needed to complete the submission. The party must provide the requested information within 30 calendar days from the date on the request.

(b) If DEQ determines the submission is complete, DEQ must notify the party in writing of the completeness determination.

(c) If DEQ does not notify the party in writing of the completeness determination within 30 calendar days of receipt of the registration application, the application is automatically deemed complete.

(3) **Determination of carbon intensity values.** DEQ must review the proposed carbon intensity values to determine if they are accurate. DEQ must review proposed carbon intensity values as follows:

(a) For a proposed carbon intensity value listed in Table 1 or 2 under OAR 340-253-3010 or -3020, DEQ must review whether the fuel type accurately matches the fuel and fuel production process of the proposed carbon intensity value listed.

(b) For a proposed individual carbon intensity value, DEQ must approve the carbon intensity value or notify the party which carbon intensity value to use under OAR 340-253-0450.

(4) **Registration approval**. DEQ must notify the party in writing of its registration approval. The notification must include confirmation of the carbon intensity value for each fuel type to be used in calculating surpluses and shortfalls under OAR 340-253-1020.

(5) **Modifications to registration**.

(a) The party must submit an amended registration to DEQ within 30 days of any change occurring to information described in section (1), including any change that would result in a different carbon intensity value.

(b) DEQ may require a party to submit an amended registration based on new information that DEQ obtains from any source.

(6) **Opting out**. To opt-out, an opt-in party must notify DEQ in writing. Regulated parties may not opt-out.

340-253-0600

Records

(1) **Records.** Each regulated and opt-in party must retain the following records for at least five years:

(a) Copies of all data and reports submitted to DEQ;

(b) Records of each fuel transaction made including:

(A) Volume of fuel;

(i) In gallons for liquid fuels including gasoline, diesel fuel, ethanol, biomass-based diesel, liquefied natural gas and liquefied petroleum gas;

(ii) In standard cubic feet for compressed natural gas;

(iii) In kilowatt-hours for electricity; and

(iv) In kilograms for hydrogen fuel.

(B) Names of the transferor and recipient;

(C) Whether the compliance obligation was transferred from the transferor to the recipient or retained;

(D) Carbon intensity of the fuel;

(E) Producer of the fuel;

(F) Invoice date;

(G) Unique transaction identification such as a bill of lading number;

(H) Product transfer documents;

(I) Exempt status documentation under OAR 340-253-0250, if fuel is excluded from surplus and shortfall calculations under OAR 340-253-1010; and

(J) For fuel that is exported outside Oregon, where the party is the exporter of record.

(c) Records used to document how a fuel is transported or conveyed to Oregon, if not produced in Oregon;

(d) Records used to calculate the carbon intensity of the fuel;

(e) Records used to calculate surpluses and shortfalls; and

(f) Other records used to determine compliance with the Oregon Clean Fuels Program.

(2) **Review**. All data, records and calculations used by a regulated or opt-in party to comply with the Oregon Clean Fuels Program are subject to verification by DEQ. The party must provide records retained under section (1) within 60 calendar days after the date DEQ requests a review of the records, unless otherwise specified.

340-253-0630

Quarterly Reports. Quarterly reports must include the following information, in a format provided or approved by DEQ:

(1) For each fuel type sold, supplied or offered for sale in Oregon:

(a) The total volume; and

(b) Carbon intensity.

(2) Surpluses and shortfalls as calculated under OAR 340-253-1020, including the;

(a) Amount of surpluses and shortfalls generated during the quarter; and

(b) Quarterly and year-to-date net balance calculations under OAR 340-253-1030 for gasoline and gasoline substitutes and diesel and diesel substitutes.

(3) The volumes of any exempt fuels or fuels transferred to exempt users under OAR 340-253-0250; and

(4) Volumes exported outside Oregon.

340-253-0650

Annual Reports. Annual reports must include the following information, in a format provided or approved by DEQ:

(1) Company name of the regulated or opt-in party;

(2) Signature of a responsible official representing the regulated or opt-in party and certifying that the report is accurate to the best of the official's knowledge;

(3) For each fuel type sold, supplied or offered for sale during the calendar year:

(a) The total volume; and

(b) Carbon intensity.

(4) Surpluses or shortfalls as calculated under OAR 340-253-1020, including the;

(a) Amount of surpluses and shortfalls carried over from the previous year; and

(b) Amount of surpluses and shortfalls generated during the year.

(5) Net balance calculations under OAR 340-253-1030 for gasoline and gasoline substitutes and diesel and diesel substitutes;

(6) The volumes of any exempt fuels or fuels transferred to exempt users under OAR 340-253-0250; and

(7) Volumes exported outside Oregon.

340-253-1000

Surplus and Shortfall Basics

(1) **Carbon intensity values.**

(a) Except as provided in subsection (b), when calculating carbon intensity values, the regulated or opt-in party must use the DEQ carbon intensity value approved under OAR 340-253-0500.

(b) If the regulated or opt-in party has submitted a complete registration under OAR 340-253-0500 and DEQ has not approved the proposed carbon intensity value or has not determined that a different carbon intensity value more accurately reflects the fuel type, the party must use the carbon intensity value proposed in its registration.

(2) **Fuel quantities.** When calculating and reporting fuel quantities, the regulated or opt-in party must:

(a) Use energy units in MJ. To convert other energy units to MJ, the party must multiply the unit by the corresponding energy density under Table 3 under OAR 340-253-3030, and use the BTU-to-MJ conversion factor of 1,055 J per BTU.

(b) Express quantities to the nearest whole unit applicable for that quantity such as gallons, standard cubic feet, kilowatt-hours or pounds.

(3) **Metric tons of CO2 equivalent.** When reporting surpluses and shortfalls, the regulated or opt-in party must express quantities to the nearest whole metric ton of carbon dioxide equivalent.

(4) **Surplus generation.** A party generates a clean fuel surplus when:

(a) The carbon intensity of a fuel identified under OAR 340-253-1010 is lower than the corresponding baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes;

(b) The party has a DEQ-approved carbon intensity value; and

(c) The party demonstrates that the fuel is:

(A) Biodiesel, ethanol, or any other liquid fuel other than liquefied natural gas delivered to a public or private access fueling facility in Oregon;

(B) Electricity used in Oregon to charge a motor vehicle; or

(C) Compressed or liquefied natural gas, hydrogen fuel or liquefied petroleum gas dispensed in Oregon for use in a motor vehicle.

(5) **Shortfall generation.** A party generates a clean fuel shortfall when:

(a) The carbon intensity of a fuel identified under OAR 340-253-1010 is higher than the corresponding baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes; and

(b) The fuel is imported to Oregon or produced by an Oregon producer for use in Oregon for use in a motor vehicle.

(6) **Nature of surpluses**. Clean fuel surpluses are a regulatory instrument and do not constitute personal property, instruments, securities or any other form of property. Surpluses are not credits and may not be used to meet any compliance obligations other than as specified in this division.

340-253-1010

Fuels to include in surplus and shortfall calculation

(1) **Fuels included.** A regulated or opt-in party must calculate surpluses and shortfalls for all regulated and opt-in fuels under OAR 340-253-0200 that are not otherwise exempt under OAR 340-253-0250, excluding fuels that are exported outside Oregon.

(2) **Fuels excluded**. Except as provided in section (3), the regulated or opt-in party may not include fuels excluded under OAR 340-253-0250 in surplus and shortfall calculations.

(3) **Fuels sold to exempt users**. The regulated or opt-in party may include or exclude fuel sold to an exempt user under OAR 340-253-0250 from the surpluses and shortfalls calculations.

(a) If the party includes the fuel, the party must include all fuel volumes listed on an invoice or all fuels included in a single or simultaneous delivery of fuel, regardless of how many invoices are used.

(b) If the party excludes the fuel, the party must document and report all excluded fuels under OAR 340-253-0600 through OAR 340-253-0650.

340-253-1020

Calculating Surpluses or Shortfalls

(1) The regulated or opt-in party must calculate surpluses and shortfalls for each fuel type included under 340-253-1010 using the surplus and shortfall basics under OAR 340-253-1020 to calculate the following:

(a) Energy in MJs by multiplying the amount of fuel by the energy density of the fuel in Table 3 under OAR 340-253-3030;

(b) Adjusted energy in MJs by multiplying the energy in MJs from (1)(a) by the energy economy ratio of the fuel using Table 4 or 5 under OAR 340-253-3040 or -3050 for gasoline and gasoline substitutes or diesel fuel and diesel substitutes;

(c) Carbon intensity difference by subtracting the fuel's carbon intensity value from the corresponding baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes;

(d) Grams of carbon dioxide equivalent by multiplying the adjusted energy in MJs in (1)(b) by the carbon intensity difference in (1)(c); and

(e) Metric tons of carbon dioxide equivalent by dividing the grams of carbon dioxide equivalent in (1)(c) by 1,000,000.

(2) If the fuel has a carbon intensity:

(a) Higher than the corresponding baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes, the absolute value of the metric tons of carbon dioxide equivalent under subsection (1)(e) is a shortfall.

(b) Lower than the corresponding baseline carbon intensity value for gasoline and gasoline substitutes or diesel fuel and diesel substitutes, the absolute value of the metric tons of carbon dioxide equivalent under subsection (1)(e) is a surplus.

340-253-1030

Net Balance Calculation. A regulated or opt-in party must calculate the net balance at the end of the reporting period using the following formula: Net balance = $\text{Surpluses}_{\text{Generated}} + \text{Surpluses}_{\text{Forward}} - \text{Shortfalls}_{\text{Generated}} - \text{Shortfalls}_{\text{Forward}}$ where:

(1) $\text{Surpluses}_{\text{Generated}}$ is the total surpluses generated using calculations under OAR 340-253-1020;

(2) $\text{Surpluses}_{\text{Forward}}$ is the surpluses carried forward from the previous reporting period;

(3) $\text{Shortfalls}_{\text{Generated}}$ is the total shortfalls generated using calculations under OAR 340-253-1020; and

(4) $\text{Shortfalls}_{\text{Forward}}$ is the shortfall carried forward from the previous reporting period.

340-253-3000

Tables used for the Oregon Clean Fuels Program

340-253-3010
Table 1 - Oregon Carbon Intensity Lookup Table for Gasoline and Gasoline Substitutes

Table 1

Oregon Carbon Intensity Lookup Table for Gasoline and Gasoline Substitutes

Fuel	Feedstock/Fuel Production Process	Carbon Intensity Values (gCO2e per MJ)			
		Direct Emissions	Land Use Change or Other Indirect Effect	Energy Economy Ratio Applied	Final
Gasoline	Based on a weighted average of gasoline supplied to Oregon	92.34	-	1	92.34
Ethanol from Corn	GREET default adjusted for transport to Oregon	64.80	-	1	64.80
	Wet Mill, Natural Gas	64.52	-	1	64.52
	Wet Mill, Coal	90.99	-	1	90.99
	Dry Mill, Wet DGS, Natural Gas	57.00	-	1	57.00
Ethanol from Sugarcane	GREET defaults adjusted for transport to Oregon	26.44	-	1	26.44
Cellulosic Ethanol	Farmed trees	15.54	-	1	15.54
	Wheat straw	20.90	-	1	20.90
	Forest residue	20.49	-	1	20.49
	Mill waste	12.31	-	1	12.31
Compressed Natural Gas	North American natural gas delivered via pipeline; compressed in Oregon	71.41	-	1	71.41
	Landfill gas cleaned to pipeline quality	11.26	-	1	11.26
Liquefied Natural Gas	North American natural gas delivered via pipeline; liquefied in Oregon w/ 80% efficiency	83.13	-	1	83.13
	Overseas liquefied natural gas delivered to Oregon; re-gasified then re-liquefied w/ 80% efficiency	93.37	-	1	93.37
	Overseas liquefied natural gas delivered to Oregon; no re-gasification or re-liquefaction	77.50	-	1	77.50
Electricity	Oregon average electricity mix 2015	154.98	-	4.1	37.81
	Oregon average electricity mix 2016	154.98	-	4.0	38.75
	Oregon average electricity mix 2017	154.98	-	3.9	39.74
	Oregon average electricity mix 2018	154.98	-	3.8	40.78
	Oregon average electricity mix 2019	154.98	-	3.7	41.89
	Oregon average electricity mix 2020	154.98	-	3.6	43.05
	Oregon average electricity mix 2021	154.98	-	3.5	44.28
	Oregon average electricity mix 2022	154.98	-	3.4	45.58
	Oregon average electricity mix 2023	154.98	-	3.3	46.96
	Oregon average electricity mix 2024	154.98	-	3.2	48.43

	Oregon average electricity mix 2025	154.98	-	3.1	49.99
Liquefied Petroleum Gas	Liquefied Petroleum Gas, Crude and NG Mix	83.05	-	1	83.05

340-253-3020
Table 2 - Oregon Carbon Intensity Lookup Table for Diesel Fuel and Diesel Substitutes

Table 2

Oregon Carbon Intensity Lookup Table for Diesel Fuel and Diesel Substitutes

Fuel	Feedstock/Fuel Production Process	Carbon Intensity Values (gCO2e per MJ)			
		Direct Emissions	Indirect Land Use Change or Other Indirect Effect	Energy Economy Ratio Applied	Final
Ultra Low Sulfur Diesel	Based on a weighted average of diesel fuel supplied to Oregon	91.53	-	1	91.53
Renewable Diesel	Soybeans to renewable diesel	21.70	-	1	21.70
Biodiesel	Soybean GREET default adjusted for transport to Oregon	20.00	-	1	20.00
	Canola	27.31	-	1	27.31
	Used cooking oil to fatty acid methyl esters – FAME	10.3	-	1	10.3
	Tallow	16.85	-	1	16.85
Compressed Natural Gas	North American natural gas delivered via pipeline; compressed in Oregon	71.41	-	0.94	75.97
	Landfill gas cleaned to pipeline quality	11.26		0.94	11.98
Liquefied Natural Gas	North American natural gas delivered via pipeline; liquefied in Oregon w/ 80% efficiency	83.13	-	0.94	88.44
	Overseas liquefied natural gas delivered to Oregon; re-gasified then re-liquefied w/ 80% efficiency	93.37	-	0.94	99.33
	Overseas liquefied natural gas delivered to Oregon; no re-gasification or re-liquefaction	77.50	-	0.94	82.45
Electricity	Oregon average electricity mix	154.98	-	2.70	57.4
Liquefied Petroleum Gas	Liquefied Petroleum Gas, Crude and NG Mix	83.05	-	1	83.05

340-253-3030
Table 3 - Oregon Energy Densities of Fuels

Table 3

Oregon Energy Densities of Fuels	
Fuel (units)	**MJ/unit**
Gasoline (gallon)	116.09 (MJ/gallon)
Diesel fuel (gallon)	129.49 (MJ/gallon)
Compressed natural gas (standard cubic feet)	0.98 (MJ/standard cubic feet)
Electricity (kilowatt hour)	3.60 (MJ/kilowatt hour)
Denatured Ethanol (gallon)	80.53 (MJ/gallon)
Neat Biomass-based Diesel (gallon)	119.55 (MJ/gallon)
Liquefied natural gas (gallons)	100.00 (MJ/gallon)
Hydrogen (kilograms)	123.00 (MJ/kilogram)
Liquefied petroleum gas (gallons)	96.5 (MJ/gallon)

340-253-3040
Table 4 - Oregon Energy Economy Ratios for Fuel used in Light-Duty Applications

Table 4

Oregon Energy Economy Ratios for Fuel Used in Light-Duty Applications

Year	Fuel/Vehicle Combination Energy Economy Ratio			
	Gasoline or any ethanol blend	**Compressed natural gas / liquefied petroleum gas/ Internal combustion engine vehicle**	**Hydrogen or fuel cell vehicle**	**Electricity / battery electric vehicle, or plug-in hybrid electric vehicle**
2015	1.0	1.0 (needs to be adjusted: not reformulated gasoline)	3.0 (needs to be adjusted: not reformulated gasoline)	4.1
2016	1.0	To be announced[1]	3.0	4.0
2017	1.0	To be announced[1]	2.9	3.9
2018	1.0	To be announced[1]	2.8	3.8
2019	1.0	To be announced[1]	2.8	3.7
2020	1.0	To be announced[1]	2.7	3.6
2021	1.0	To be announced[1]	2.6	3.5
2022	1.0	To be announced[1]	2.5	3.4
2023	1.0	To be announced[1]	2.5	3.3
2024	1.0	To be announced[1]	2.4	3.2
2025	1.0	To be announced[1]	2.3	3.1

[1] A future Clean Fuels Program review will include analysis of the energy economy ratios for light-duty applications to determine the values for 2015 through 2025.

340-253-3050
Table 5 - Oregon Energy Economy Ratios for Fuel Used in Heavy-Duty Applications

Table 5

Oregon Energy Economy Ratios for Fuel Used in Heavy-Duty Applications

Fuel/Vehicle Combination Energy Economy Ratio			
Diesel fuel or Biomass-based diesel blends	**CNG or LNG**	**Hydrogen or fuel cell vehicle**	**Electricity / battery electric vehicle, or plug-in hybrid electric vehicle**
1.0	0.94	1.9	2.7

Summary of public comment and agency responses

Title of Rulemaking: Oregon Clean Fuels Program
Prepared by: Cory-Ann Wind
Date: November 2, 2012

Comment period

DEQ opened the public comment period July 20, 2012, and closed it at 5 p.m. on Aug. 31, 2012. DEQ held a public hearing hosted by the Environmental Quality Commission Aug. 24, 2012, at 9 a.m. at the DEQ headquarters office, 811 SW 6th Avenue, Portland, Oregon. DEQ regional offices in Eugene, Medford, Bend and Pendleton were also open to citizens to participate in the hearing via conference phone. 15 individuals in Portland and one in Medford testified. 102 people submitted comments; 16 oral and 87 written.

Organization of comments and responses

Summaries of individual comments and DEQ's responses are provided below. Comments are summarized in categories. Those who provided each comment are referenced by number. A list of commenters and reference numbers follows the summary of comments and responses.

Summary of comments and agency responses			
Comment #	**Comment**	**DEQ's response**	**Reference #**
1	Adopt standard and move forward with the Clean Fuels Program. Support removing sunset.	Thank you for your comment.	5, 6, 7, 12, 14, 17, 18, 19, 21, 22, 26, 27, 32, 35, 40, 42, 48, 49, 50, 51, 52, 54, 55, 56, 61, 63, 64, 66, 72, 79, 80, 84, 87, 89, 92, 94, 97, 102
2	Support Clean Fuels Program as a key element to achieving a clean, low-carbon energy future. Improve environmental performance of the transportation system. Program to provide strong incentive for sustainable fuel companies to set up operations in Oregon.	Thank you for your comment.	1, 20, 23, 28, 31, 58, 62, 67
3	Adopt Clean Fuels Program. Concerned about the air pollution	Thank you for your comment.	2, 8, 10, 47, 53, 60, 77,

	and greenhouse gas emissions associated with burning fossil fuels.		86, 98
4	Opposes Clean Fuels Program. Suspend further action. Do not adopt the Program.	In response to comments, DEQ proposes to remove the deferred Phase 2 requirements from this rulemaking. As originally intended, DEQ will use the information collected in this administrative phase of program, along with continued discussions with stakeholders and legislators, to inform our recommendations for the next phase of the program.	3, 11, 13, 15, 25, 43, 65, 69, 71, 95, 96, 99, 100
5	The program will put Oregon at a competitive disadvantage to other states.	In response to comments, DEQ proposes to implement only the Phase 1 requirements at this time. As a result, businesses in Oregon will not be at a competitive disadvantage to those in other states. If Phase 2 is adopted, DEQ will to evaluate and refine the program design to ensure that this does not occur.	4, 69, 71
6	The Oregon program is modeled after an unconstitutional California program.	Several stakeholder groups are challenging California's program in court and Oregon is following those proceedings. The issues under litigation in California do not apply to Phase 1 of Oregon's program. When a final ruling is made on the California lawsuit, we will analyze the outcome to see what, if any, changes are needed to the Oregon program.	3, 4, 11, 25, 69, 71, 88, 95, 99, 100
7	The new CAFE standards negate the need for this program.	Cleaner car technology (more miles per gallon) is only part of the solution to reducing greenhouse gas emissions from transportation sources. Providing cleaner fuels (fewer emissions per gallon) and driving less (fewer miles travelled) must also be part of the solution.	4
8	This program is effectively a cap and trade program.	The Clean Fuels Program does not set a cap on emissions. It establishes a performance standard that is an average amount of carbon emitted per unit of energy. Regulated parties must meet the standards and can choose how to comply with that standard by supplying lower carbon fuels or purchasing credits.	4
9	There is concern about the effects of	During this first phase of the program,	3, 71, 100

	higher blends of biofuels.	there is no requirement to change from the current supply of fuels so there should not be any added concern from the blends that are currently available. If adopted at a later date, the second phase of the program would not change any of the state or federal requirements on the amount of biofuels that can be blended with gasoline or diesel.	
10	The lower carbon fuels needed for this program do not exist in commercial quantities. This will lead to higher fuel costs.	House Bill 2186 specifically required safeguards to protect against increased fuels costs due to the program. During Phase 1, the proposed rule will not require any new fuels. Even so, many lower carbon fuels exist today at commercial quantities and at lower costs than petroleum fuel. Natural gas, propane, electricity, biodiesel made from soy beans, canola and recycled cooking oil and ethanol made from corn and sugar cane are all current options. If Phase 2 is adopted later, it will be gradually phased in to ensure time for additional low carbon fuels to be available in necessary quantities.	3, 4, 25, 69, 71, 95, 96, 100
11	The program almost immediately relies on the availability of cellulosic ethanol.	The economic analysis conducted determined that Oregon fuel distributors will be able to meet the standards for at least the first five years if Oregon receives its proportional share of renewable fuels already required by the federal Renewable Fuels Standard. Expanded use of cellulosic ethanol is one of many potential compliance options that fuel distributors may use when and if Phase 2 of the program is adopted. During this first phase of the program, there is no requirement to change from the current supply of fuels.	4, 11
12	The economic analysis incorrectly assumes that there are no Oregon cellulosic ethanol facilities to offset the negative economic impacts of the program.	Cellulosic feedstocks can be agricultural wastes, forest residue, recovered construction materials and dedicated energy crops; all of which can be grown or gathered in Oregon. Currently, there is a cellulosic ethanol facility being constructed in Boardman that will	4

		produce ethanol from farmed hybrid poplar trees and wheat straw.	
13	Special blending formulations, requiring special equipment, logistics and compliance costs, will be necessary and passed on to the consumer. Fuel distributors that provide fuel to exempt parties may need additional capacity in order to provide different blends to multiple customers.	The Clean Fuels Program provides great flexibility in approaches regulated parties may use to comply with the standards. Because of this, DEQ expects that fuel distributors will select the least-cost option for meeting the standards when and if Phase 2 applies. During this first phase of the program, there is no requirement to change from the current supply of fuels.	4, 15, 25, 65, 71, 100
14	The release mechanisms for suspending the program due to price increase or supply shortage is inadequate.	This comment is not applicable to the Phase 1 requirements proposed in this rulemaking. House Bill 2186 directed EQC to provide safeguards in the form of exemptions and deferrals to prevent fuel supply or price issues that could put Oregon at a competitive disadvantage. DEQ has proposed a mechanism the agency believes will be effective if adequately funded. DEQ will evaluate, refine and test the deferral mechanisms during the implementation of Phase 1.	4, 11, 25, 65, 69, 71, 99, 100
15	Include propane, liquefied petroleum gas, as an opt-in fuel in the program.	DEQ agrees to add propane into the program as an opt-in fuel and has made the appropriate changes throughout the rules.	9, 74
16	The federal Renewable Fuel Standard negates the need for this program.	The federal renewable fuel standard does not necessarily guarantee lower carbon fuels. The standard also does not apply to all lower carbon fuels such as electricity, propane or natural gas. The renewable fuel standard is a national production mandate, but it does not create demand for renewable fuel to be consumed in Oregon. Since Oregon is committed to reaching its greenhouse gas reduction goals, the Clean Fuels Program is needed to ensure that greenhouse gas reduction from transportation sector fuels occurs in Oregon.	11, 71
17	We support the market-based, technology-neutral policy to cut petroleum dependence, reduce carbon emissions and create a	Thank you for your comment.	16, 24, 29, 30, 39, 59, 93, 97

	market for new clean fuels.		
18	Deferring the actual reductions of lifecycle carbon emissions delays the economic and health benefits of the program and extends the volatility of the petroleum market.	DEQ agrees that delaying Phase 2 delays the benefits of the program. DEQ is committed to working with the elected officials, stakeholders and the EQC to develop and implement the next phase of the program as directed by the Legislature. Delayed benefits will be considered alongside costs and other implementation issues as part of DEQ's recommendation for Phase 2.	18, 38
19	Amend language for the party generating credits with liquefied natural gas.	OAR 340-253-0320(3) and (4) have been changed to "the owner of the liquefied natural gas when it is transferred to the facility at which the liquefied natural gas is dispensed to motor vehicles."	19
20	Incorporate indirect land use change into program. Defer inclusions of indirect land use change into program.	Acting on the recommendation of its low carbon fuel standards advisory committee, DEQ chose not to include factors for indirect effects at this time. While acknowledging its existence, DEQ is choosing to wait until the scientific in this area becomes clearer. DEQ will evaluate this issue in its recommendation for Phase 2.	33, 71, 88, 100
21	Expand the credit market beyond the regulated and opt-in parties.	The prohibition against non-regulated and non-opt-in parties participating is intended to ensure that outside speculation does not alter the credit market. The low carbon fuel standards advisory committee discussion of this issue can be found on page 89 of DEQ's final report. Since this recommendation is not needed until Phase 2, DEQ will continue to evaluate options for expanding the credit market.	33
22	Develop an electronic trading platform to facilitate a real-time market for clean fuels credits.	Since this recommendation is not needed until Phase 2, DEQ will continue to evaluate options for an electronic trading platform.	33
23	Incorporate a flexible compliance mechanism to provide certainty to a regulated party if they are unable to meet the standard.	Since this is a Phase 2 issue, DEQ will evaluate options for creating a flexible compliance mechanism in the next phase of the program.	33
24	Support this bipartisan initiative. As people involved in the low carbon	Thank you for your comment.	34, 36, 37, 44, 45, 46,

	fuel industry, we depend on the market certainty that the program can provide. Adopt program and support removal of the sunset.		68, 73, 83, 90, 91, 103
25	Supporting "good" not just punishing "bad". Not overly prescriptive, leaves freedom to innovate. Catalyst to other Oregon industries. Reporting costs are not a major concern.	Thank you for your comment.	38
26	Decisions about low carbon fuels should be made at the federal level.	Thank you for your comment. At this time, a low carbon fuel standard is not being considered at the federal level. It is possible that development of innovative approaches to address the carbon intensity of fuel at the state level will eventually lead to a federal program.	41
27	Include all applicable tax credits and incentives as well as federal RIN values when establishing the average price of fuels.	Since this is a Phase 2 issue, refinement of these provisions can continue to be developed pending a future rulemaking. DEQ will consider these factors when assessing the price and availability of low carbon fuels that would be needed when and if Phase 2 of the program is adopted.	57
28	A description of credit transactions is not included.	Since this is a Phase 2 issue, DEQ can continue to refine these provisions pending a future rulemaking. Phase 1 of the program does not include the generation, banking or transfer of credits. DEQ will evaluate the need for further description of credit transactions in developing its recommendation for Phase 2.	71
29	The fiscal analysis should include fee on regulated parties.	While the potential for a fee on regulated parties was identified in the public notice for the Clean Fuels Program, it was not included in the fiscal and economic impact because it is only a legislative concept at this time. If the Legislature approves fee authority, DEQ will conduct a separate rulemaking to establish a fee schedule and will work with stakeholders to assess its fiscal and economic impact.	71, 100
30	The fiscal and economic impact statement should include implementation of the full (both	The fiscal and economic impact analysis includes both parts of the program; because the requirements of Phase 2 were	71, 100

	Phase 1 and 2) program.	deferred in the proposal, the cost to comply with Phase 2 was determined to be zero. The revised proposal only includes Phase 1, so the cost of Phase 2 remains zero. If DEQ initiates rulemaking to adopt Phase 2, the fiscal and economic impact will be analyzed to incorporate the cost of complying with the Phase 2 requirements.	
31	The program should recognize that different fuels have different sources and different impacts and should consider a multimedia evaluation.	With regards to greenhouse gas emissions, the lifecycle analysis used in this program accounts for these differences. However, the non-GHG impacts are not currently addressed in the program and will be considered in a future program review if Phase 2 of the program is adopted.	72, 100
32	Recommend energy density and carbon intensity for propane.	DEQ has updated OAR 340-253-3010, -3020 and -3030 (the tables for carbon intensity and energy density) for propane.	75
33	Registration requirements in multiple locations are confusing.	OAR 340-253-0100(2), (4) and OAR 340-253-0500 have all been modified to be consistent.	76
34	The amount of information required for registration is unwarranted.	The language in OAR 340-253-0500(1) has been modified to be more focused.	76, 100
35	Include process to update fuel registration.	OAR 340-253-0500(5) includes a process to modify a registration within 30 days of changing any information contained in the original registration.	76
36	Quarterly reporting in Phase 1 is unnecessary.	During the initial phase of the program, one of the objectives of the quarterly report is to gain experience with calculating surpluses and shortfalls relative to the baseline carbon intensity values. This exercise is largely the same as that of calculating credits and deficits if the next phase of the program is implemented. Implementing just Phase 1 at this time will allow both regulated parties and DEQ time to refine recordkeeping and reporting tools to minimize the cost of complying with the next phase of the program. In partial response to the comment, however, DEQ proposes to delay the initial quarterly report from 2013 until 2014.	76, 100

37	Change definition of importer to "the person who owns the fuel when it enters into Oregon."	If the definition of importer were changed as suggested, there is the potential that truckers, railroads, barges and other transporters could become regulated. In an attempt to minimize the number of small businesses being regulated (in response to comments received during the fiscal advisory committee process), the clarification language of "in the stationary storage tank into which the product was first transferred after it was imported" was inserted.	76
38	There should be separate treatment of rack sales and bulk sales.	One of the objectives of the initial phase of this program is to collect enough information to inform the development of the next phase. For this phase, DEQ has determined that inclusion of all sales, both rack and bulk, are necessary to recommend whether to include both rack and bulk sales into the requirements for implementation of the next phase of the program.	76
39	Records for export volumes should be required only for volumes for which the party is the exporter of record.	DEQ amended OAR 340-253-0600(1)(J) to add the phrase "where the party is the exporter of record."	76, 100
40	The product transfer documents should identify the fuel and CI value and who the fuel was received from.	DEQ modified OAR 340-253-0600(1)(b) to include this information.	76
41	Request 60 days to respond to a records request instead of 15.	DEQ changed OAR 340-253-0600(2) 15 to 60 days.	76
42	Numbering in OAR 340-253-0310(5) is incorrect.	OAR 340-253-0310 has been renumbered.	76
43	Provide an opportunity for out-of-state producers and marketers to voluntarily opt-in to the program.	DEQ is very interested in incorporating this provision into the Oregon program. We will work with California and stakeholders to develop provisions that can be included in a future rulemaking.	78, 88
44	Agree with definition and requirements of "small importer".	Thank you for your comment.	78
45	Develop web-based registration form.	DEQ intends to modify California's electronic registration form for use in Oregon.	78
46	Please clarify what needs to be included in quarterly versus annual	OAR 340-253-0650 outlines the annual reporting requirements while OAR 340-	78

	reports.	253-0630 outlines the quarterly reporting requirements. For 2013, DEQ expects the annual report to cover the July 1 – December 31 period. For 2014 and beyond, DEQ expects the regulated party to submit information for each quarter including the calculation of surpluses and shortfalls and the net balance calculation as compared to the baseline carbon intensity values for that quarter and year-to-date.	
47	Request on-line listing of registered buyers and sellers.	DEQ intends to provide an on-line list of all parties registered with the program, for both regulated and opt-in parties.	78
48	Please clarify the documentation required for product transfers.	DEQ understands that the bill of lading for a specific volume of fuel transfers from the seller to the buyer upon transfer of the fuel and that the seller no longer has possession of that document once the fuel is transferred. The proposed rules require that there be another legal document that can serve the same purpose for the seller so that it is possible to pair up a seller's and a buyer's documents for the same volume of fuel in order to verify the transfer.	78
49	Additional information is needed to identify individual volumes of fuels transferred.	DEQ has amended OAR 340-253-0600 to include additional requirements.	78
50	Amend requirements for rounding.	DEQ has amended OAR 340-253-1000 to remove specific rounding requirements.	78
51	Credits should not have an expiration date.	This comment is consistent with DEQ's final report of the low carbon fuel standards advisory committee. DEQ concluded that allowing credit banking with no expiration date will encourage early reductions, allow for compliance flexibility and improve the stability of the credit market. However, because credits may not be generated during Phase 1 of the program, the revised proposal does not include provisions for credit generation, banking or transfer. These provisions will be added when and if the next phase of the program is adopted.	78

52	Baseline year should be 2010.	The proposed rules retain the 2010 baseline year for purposes of calculating surpluses and shortfalls during Phase 1. DEQ will explore options for an appropriate program baseline as we continue design work for the next phase of the program.	80
53	Include expertise in fuel pricing and/or supply to implement deferrals.	During Phase 1, DEQ intends to work with the Oregon Department of Energy to test and develop implementation plans for the deferrals. DEQ also plans to recommend hiring or contracting with fuel experts to implement the deferrals when and if the next phase of the program is adopted.	80
54	Do not include all the states in the PADD 5 to compare fuel costs.	DEQ agrees that not all PADD 5 states should be included for the best comparison to Oregon's fuel prices when and if Phase 2 of the program is adopted. The Actual PADD 5 includes Oregon, Washington, Arizona, Nevada, California, Alaska and Hawaii. However, House Bill 2186 defined PADD 5 for purposes of fuel price comparisons as just Oregon, Washington, Arizona and Nevada. The Statutory PADD 5 excludes California since it has a low carbon fuel standard, as well as Alaska and Hawaii since their fuel supplies and costs are significantly different than Oregon's. For gasoline, Oregon's prices would be compared to the other members of the Statutory PADD 5, including Washington, Arizona and Nevada. For diesel, information is not available for the Statutory PADD 5, so DEQ may need to compare Oregon's prices to the average prices for the Actual PADD 5. However, it is DEQ's intent to work with fuel providers to gather diesel price information specific to the Statutory PADD 5 if possible.	80
55	We support the use of exemptions to consider safety, performance and supply issues.	Thank you for your comment.	80

56	We support provision to include new fuels in the future.	Thank you for your comment.	80
57	Extend out-of-state clean fuel supply penalty to the entire northwest.	The program does not have a clean fuel source no-penalty zone or any other similar concept. If the next phase of the program is adopted, all transportation fuel produced or imported to Oregon will need to meet the average carbon intensity standards. Fuel suppliers will compete equally, based on the lifecycle greenhouse gas emissions per unit of energy for their fuels, regardless of where the fuels were produced.	80
58	Extend exempt status of short-line railroads to be a permanent exemption.	DEQ agrees that the short-line railroads face the same fuel supply and distribution issues that justified the exemption for Class 1 railroads. Therefore, DEQ has revised the proposal to exempt the fuel used in short-line railroads from the Clean Fuels Program.	81
59	Opt-in parties should not have the compliance obligation.	Opting in to the program is entirely voluntary. DEQ assumes that an opt-in party is in a position to generate surpluses (credits). The only compliance obligation for an opt-in party is to keep records to document the generation of surpluses (credits) and submit reports. These minimal requirements are an integral part of the credit market to ensure the validity of credits being transferred.	82
60	Credits for electricity should flow to those making the investment.	OAR 340-253-0330 is intended to provide certainty to those involved in providing electricity for use as a transportation fuel. The proposed hierarchy was a way to offer the value of the credits to those most likely to invest, and not preclude any individuals' participation. DEQ recognizes the importance of harmonizing the Clean Fuel Program's rules with those of the Oregon Public Utility Commission and we will continue to work with the PUC and stakeholders to eliminate any unnecessary barriers to participation in the program.	82

61	Rules lack specificity regarding enforcement.	DEQ did not propose any enforcement rules specific to the Clean Fuels Program at this time. Existing rules in OAR 340 Division 12 specify penalties for violations of requirements to register, keep records and report and are adequate for Phase 1 of the program. DEQ intends to rely primarily on technical assistance during the initial phase of the program unless violations are egregious. DEQ will include specific enforcement rules and guidance for Phase 2 when and if DEQ proposes rules for that phase of the program.	82
62	Fundamental weaknesses of the low carbon standard: quantitative regulations are inherently inefficient and ineffective; the off-ramps offer uncertainty and are too complex; no realistic prospect of influencing technological developments, production or pricing of fuels in Oregon; the economic analysis conducted is too simplistic.	DEQ disagrees and has determined, based on its work with its low carbon fuel standards advisory committee, that an Oregon Clean Fuels Program is both achievable and cost-effective. However, the commenter's concerns will be further evaluated as part of DEQ's exploration of the feasibility of Phase 2.	85, 100
63	Support two-phased approach.	Thank you for your comment.	88
64	Use most recent version of GREET available or CA-GREET.	DEQ intends to maintain OR-GREET so that it is current with improvements in carbon intensity modeling science. If a regulated party wishes to propose a carbon intensity based on a model other than the currently approved version of OR-GREET, the party must document the differences between the two versions of GREET so DEQ can assess the accuracy and reliability of the calculations.	88, 100
65	Amend the energy density value for ethanol to represent denatured ethanol.	DEQ has changed Table 3 under OAR 340-253-3030.	88
66	Improper to focus on small businesses based on number of employees.	ORS183.310(10) defines small business for the purposes of conducting its Statement of Need and Fiscal and Economic Impact. Broader discussions about how the proposed regulations could impact businesses outside of this definition can be found in other parts of	100

		the document, including how volume or the number of fuel types affect the resources that are needed to comply. DEQ has also proposed to define a Small Oregon Importer based on the volume of fuel imported.	
67	In investigating an emergency supply shortage, the previous year's credit generation should not be relevant.	Because deferrals are not needed during Phase 1, the revised proposal does not include the deferral rules originally proposed. However, DEQ believes that banked credits are relevant to determining whether or not a deferral should be issued due to an unexpected disruption of low carbon fuel supplies. DEQ's intent is to work with the parties involved in the supply shortage to estimate the volume, carbon intensity and potential impact of the shortage. If the affected parties have an adequate supply of banked credits or alternate suppliers of low carbon fuels, a deferral may not be necessary.	100
68	Oregon shouldn't be included in the statutory PADD 5 average. If information is unavailable, the actual PADD 5 should not be the default.	For gasoline, Oregon's fuel prices will be compared to the other members of the Statutory PADD 5, including Washington, Arizona and Nevada. However, since state-by-state diesel price information is not published by the US Energy Information Administration, it may be necessary to use the Actual PADD 5 for the diesel price comparison. In further evaluating options for Phase 2 of the program, DEQ will work with fuel providers to determine if it is possible to generate average diesel prices for the Statutory PADD 5, given data confidentiality considerations.	100
69	There should be a single standard, not separate standards for gasoline and diesel.	DEQ disagrees. When and if Phase 2 is adopted, separate low carbon fuel standards will be needed for gasoline and diesel fuel to promote carbon reduction in each category. The low carbon fuel standards advisory committee discussion of this issue can be found on page 72 of DEQ's final report. To increase flexibility in the program, credits	100

		generated can be used to comply with either standard.	
70	Should not have to demonstrate that the program is causing the price increase to trigger the deferral process.	DEQ disagrees. When and if Phase 2 is adopted, a price deferral should be granted only if the Clean Fuels Program causes an increase in fuel prices. Historically, the ratio of Oregon's fuel price to those of neighboring states has varied for a variety of reasons, and this variation will continue in the future whether or not Oregon fully implements the Clean Fuels Program. Because a price deferral would reduce the effectiveness of the program at reducing greenhouse gas emissions, it should only be granted if the price difference is caused by the program.	
71	The rules about the designation of regulated parties are too convoluted.	Clarity about who is regulated under the program and how the compliance obligation transfers between an initial regulated party and a recipient of fuel is a critical element of the program. In most cases, this is straightforward and follows the normal business practices for fuel suppliers. However, the rules need to allow for all possible scenarios to provide clarity to both the transferor and recipient of fuels, even though some of the scenarios described will not occur often. DEQ will provide technical assistance to help regulated parties understand the applicable rules.	100
72	Why are the baseline carbon intensities different than California's?	The baseline carbon intensity estimates for Oregon's Clean Fuels Program are based on Oregon's unique transportation fuel mix, not California's. The low carbon fuel standards advisory committee discussion of this issue can be found on pages 70 - 71 in DEQ's final report.	100
73	There are no provisions for individual carbon intensities for conventional fuels as there are for alternative fuels.	In the proposed rules, all conventional fuels must use the statewide average carbon intensities found in Tables 1 and 2. DEQ plans to update the values in these tables at least every 3 years to reflect changes in crude oil, refining techniques and other factors that affect	100

		the carbon intensities of gasoline and diesel distributed in Oregon. The advisory committee discussed several options for treating the carbon intensities of conventional fuels, and DEQ's proposed approach has been informed by the committee deliberations. A summary of this discussion can be found on pages 77 - 82 of the final committee report. DEQ is open to discuss further refinement of these provisions as part of the evaluation of the next phase of the program.	
74	Provide a simple reporting/recordkeeping alternative to the California-like reporting tool.	DEQ plans to develop a reporting tool that works for both small and large-sized parties. Our goal is for the tool to be simple to use while capturing the necessary information.	100
75	Carbon intensity information should only be required to be recorded when the compliance obligation is transferred.	DEQ has modified OAR 340-253-0600(1)(b) reflect this change.	100
76	DEQ should not be able to determine a specific pathway for a fuel.	OAR 340-253-0400 and -0450 outline a process whereby a registrant proposes a carbon intensity value that DEQ must approve. Only if DEQ disagrees with the initial proposal does the agency suggest a more appropriate value. The registrant will be able to work with DEQ to reach agreement about the carbon intensity for the pathway.	100
77	The treatment of crude oil is unclear.	All petroleum fuels receive the same carbon intensity based on a statewide average of fuels entering the state. DEQ will update this average periodically. The low carbon fuel standards advisory committee discussion of the issue can be found on page 80 in the final DEQ report. DEQ is open to discussing the refinement of provisions for treating changes in crude oil carbon intensity as part of DEQ's further evaluation of the next phase of the program.	100
78	The processes to update carbon intensities are without basis or unjustified.	DEQ must ensure the proper documentation of actual greenhouse gas reductions by using accurate and current	100

		information when calculating carbon intensity values. The low carbon fuel standards advisory committee discussion of this issue can be found on pages 79 – 82 in DEQ's final report.	
79	The difference in energy densities and energy efficiency ratios in Oregon and California need to be clarified.	Regarding energy densities, the differences between Oregon and California are due to differences in the fuel formulations required in the two states. Regarding energy efficiency ratios for electric vehicles, the difference is primarily due to the use of a declining ratio in Oregon to account for increasing fuel economy in conventional vehicles from now until the end of the program as opposed to a set value used in California. The low carbon fuel standards advisory committee discussion of the issue can be found on pages 139 - 145 of DEQ's final report.	100
80	Include additional pathways for renewable natural gas into the pipeline, renewable electricity into the grid, and renewable LPG-substitute such as di-methyl ether.	Upon receiving this comment, DEQ asked the commenter for additional information to justify the addition of these fuel pathways along with supporting documentation as to what the carbon intensities should be. Because the commenter did not respond, DEQ was not able to propose adding these pathways in this rulemaking. However, requests to include new pathways for these or any other new fuels used in Oregon can be made at any time through the new fuels pathway process in the proposed rules.	101
81	Support exemption for research, development and demonstration facilities.	Thank you for your comment. The purpose of this exemption is to avoid any regulatory barriers to innovation that may lead to cleaner fuels for Oregon.	102
82	Modify definition of "Oregon production facility" to refer to finished fuel rather than blendstock.	DEQ has modified the definition of "Oregon production facility" to refer to blendstocks and finished fuel. This clarifies that an Oregon producer of a blendstock is only required to provide documentation of the carbon intensity of the blendstock it produces, not that of the finished fuel. As the commenter correctly	102

		points out, the supplier of the finished fuel is then obligated to document the multiple blendstocks, and their carbon intensities to be able to calculate surpluses and shortfalls.	
83	Concern that rural parts of Oregon like Ontario will face higher fuel costs since the Boise terminals will not likely provide the fuels needed to comply with the program and therefore force fuel suppliers to go farther and pay a premium.	DEQ recognizes that some regional fluctuations in the price of fuels may occur due to the way fuels are distributed in Oregon. Since this is a Phase 2 issue, DEQ intends to work with the regulated parties throughout the state to collect the data needed to further refine the deferral mechanisms in Phase 2 program.	13

Reference #	Date submitted	Organization or affiliation	Contact person	City	State
1	8/30/2012	1000 Friends of Oregon	Jason Miner		
2	8/30/2012	Andy Harris, MD		Portland	OR
3	8/29/2012	Associated General Contractors	Mike Salsgiver		
4	8/30/2012	Associated Oregon Industries	John Ledger	Salem	OR
5	8/22/2012	Basey Klopp			
6	8/24/2012	Beaver Biodiesel, LLC	Daniel Shafer	Portland	OR
7	8/24/2012	Beaver Biodiesel, LLC	Daniel Shafer	Portland	OR
8	8/30/2012	Beyond Toxics	Lisa Arkin	Eugene	OR
9	8/24/2012	Blue Star Gas	Jeff Stewart		
10	8/30/2012	Bonnie Nedrow, ND		Ashland	OR
11	8/30/2012	BP America Inc.	Michael Abendhoff	Blaine	WA
12	8/23/2012	Brian Brandt		Portland	OR
13	8/24/2012	Campbell & Poole Distributing	Ken Poole	Ontario	OR
14	8/22/2012	Caroline Zaworski			
15	8/24/2012	Carson Oil Company	Lance Woodbury		
16	8/31/2012	Ceres	Carol Lee Rawn		
17	8/29/2012	Christopher Pond		Glide	OR
18	8/31/2012	City of Portland	Susan Anderson	Portland	OR
19	8/27/2012	Clean Energy	Todd Campbell	Seal Beach	CA

20	8/30/2012	Climate Solutions	Ann Gravatt		
21	8/24/2012	Climate Solutions	Ann Gravatt		
22	8/30/2012	Clipper Creek Inc.	Barry Woods	Auburn	CA
23	8/30/2012	Coalition for a Livable Future	Ron Carley		
24	8/31/2012	Conservation Law Foundation	N. Jonathan Peress		
25	8/31/2012	Consumer Energy Alliance	Michael Whatley	Houston	TX
26	8/27/2012	Craig Markham		Dundee	OR
27	8/23/2012	Darcy Cronin		Portland	OR
28	8/30/2012	Douglas County Global Warming Coalition	Stuart Liebowitz		
29	8/31/2012	Energy Independence Now	Remy Garderet		
30	8/31/2012	Environment Northeast	Jeremy McDiarmid		
31	8/30/2012	Environment Oregon	Sarah Higginbotham		
32	8/24/2012	Environment Oregon	Megan Jones		
33	8/30/2021	Environmental Entrepreneurs	Mary Solecki	San Francisco	CA
34	8/31/2012	Environmental Entrepreneurs	Chris Dennett, Alex Wall, Trevor Winnie		
35	8/24/2012	Environmental Entrepreneurs	Mary Solecki	San Francisco	CA
36	8/31/2012	General Biodiesel Seattle, LLC	Jeff Haas		
37	8/28/2012	General Biodiesel Seattle, LLC	Jeff Haas	Seattle	WA
38	8/31/2012	Good Company	Joshua Skov	Eugene	OR
39	8/31/2012	Green for All	Kimberly Freeman Brown		
40	8/28/2012	GreenWood Resources	Don Rice	Portland	OR
41	8/30/2012	Growth Energy	Tom Buis	Washington	DC
42	8/24/2012	Hans Van Der Meer	EV4Oregon		
43	8/24/2012	IBEW Local 48	Joseph Esmonde		
44	8/31/2012	Imperium Renewables, Inc.	John Plaza	Seattle	WA
45	8/30/2012	Imperium Renewables,	John Plaza	Seattle	WA

		Inc.			
46	8/31/2012	Inland Empire Oilseeds	Joel Edmonds		
47	8/30/2012	Jenny Pompilio, MD, MPH		Portland	OR
48	8/24/2012	Jim Edelson			
49	8/22/2012	Jim Hajek			
50	8/22/2012	Krista Reynolds		Portland	OR
51	8/22/2012	Marjorie Kundiger			
52	8/22/2012	Mary Lehman		Florence	OR
53	8/30/2012	Maye Thompson, RN PhD		Portland	OR
54	8/17/2012	Metro	Martha Bennett	Portland	OR
55	8/22/2012	Nancy Merrick			
56	8/22/2012	Nathan Boddie, MD, MS		Bend	OR
57	8/24/2012	National Biodiesel Board	Shelby Neal	Jefferson City	MO
58	8/30/2012	National Wildlife Federation	Nicholas Callero		
59	8/31/2012	Natural Resources Defense Council	Simon Mui		
60	8/30/2012	Northwest District Association Air Quality Committee	Sharon Genasci	Portland	OR
61	8/22/2012	Oregon Business Association	Ryan Deckert	Tigard	OR
62	8/30/2012	Oregon Environmental Council	Andrea Durbin	Portland	OR
63	8/30/2012	Oregon Environmental Council	Chris Hagerbaumer	Portland	OR
64	8/24/2012	Oregon Environmental Council	Mark Kendall	Portland	OR
65	8/22/2012	Oregon Farm Bureau	Katie Fast	Salem	OR
66	8/22/2012	Oregon Global Warming Commission	Angus Duncan	Salem	OR
67	8/30/2012	Oregon League of Conservation Voters	Doug Moore		
68	8/31/2012	Oregon Oils, Inc.	David and Matt Burns		
69	8/24/2012	Oregon Petroleum Association	Paul Romain		
70	8/30/2012	Oregon Public Health Association	Josie Henderson	Portland	OR
71	8/30/2012	Oregon Trucking	Debra Dunn	Portland	OR

		Associations, Inc.			
72	8/30/2012	Oregon Wild	Doug Heiken	Eugene	OR
73	8/31/2012	Pacific Ethanol	Neil Koehler		
74	8/2/2012	Pacific Propane Gas Association	Lana Butterfield	Wilsonville	OR
75	8/31/2012	Pacific Propane Gas Association	Lana Butterfield	Wilsonville	OR
76	8/31/2012	Phillips 66	H. Daniel Sinks	Long Beach	CA
77	8/30/2012	Physicians for Social Responsibility, Oregon Chapter	Susan Katz	Portland	OR
78	8/28/2012	POET Ethanol Products, LLC	Heather Gullic	Wichita	KS
79	8/23/2012	Port of Morrow	Gary Neal	Boardman	OR
80	8/31/2012	Port of Portland	David Breen	Portland	OR
81	8/31/2012	Portland & Western Railroad	James Irvin	Salem	OR
82	8/31/2012	Portland General Electric	Brendan McCarthy		
83	8/31/2012	PowerStock	Bill Levy		
84	8/24/2012	PowerStock	Harrison Pettit		
85	8/29/2012	QuantEcon, Inc.	Randall Pozdena	Manzanita	OR
86	8/30/2012	Rachel's Friends Breast Cancer Coalition	Alice Shapiro	Florence	OR
87	8/22/2012	Raymond Dukes			
88	8/31/2012	Renewable Fuels Association	Bob Dinneen		
89	8/22/2012	Roni Jensen			
90	8/31/2012	SeQuential Biofuels	Ian Hill		
91	8/31/2012	SeQuential-Pacific Biodiesel	Tyson Keever, Kevin Kuper, Gavin Carpeter		
92	8/24/2012	SeQuential-Pacific Biodiesel	Gavin Carpenter		
93	8/31/2012	Sierra Club	Kathryn Phillips		
94	8/31/2012	Sierra Club Oregon Chapter	Ivan Maluski	Portland	OR
95	8/30/2012	Smooth Water Construction Company	Lenn and Denise Ball	Arlington	OR

96	8/24/2012	Tyree Oil	Ron Tyree		
97	8/30/2012	Union of Concerned Scientists	Jeremy Martin	Cambridge	MA
98	8/30/2012	Upstream Public Health	Mel Rader	Portland	OR
99	8/24/2012	Western States Petroleum Association	Frank Holmes	Sacramento	CA
100	8/30/2012	Western States Petroleum Association	Catherine H. Reheis-Boyd	Sacramento	CA
101	8/7/2012	Whole Energy	Atul Deshmane		WA
102	8/27/2012	ZeaChem Inc.	Jim Imbler	Lakewood	CO
103	8/31/2012	ZeaChem, Inc.	Jim Imbler	Lakewood	CO

Oregon Department of Environmental Quality
Chapter 340 Rulemaking

Relationship to Federal Requirements

Rule Caption:
Oregon Clean Fuels Program for fuel suppliers and producers of transportation fuels

Answers to the following questions identify how the proposed rulemaking relates to federal requirements and the justification for differing from, or adding to, federal requirements. This statement is required by OAR 340-011-0029(1).

1. Is the proposed rulemaking different from, or in addition to, applicable federal requirements? If so, what are the differences or additions?

There is no applicable federal requirement equivalent to the proposed rulemaking. The closest federal requirements, in comparing the goal of reducing greenhouse gas emissions from transportation fuels, would be the federal Renewable Fuel Standards. The Renewable Fuel Standards mandate the production of specific volumes of renewable fuels in transportation fuel, and require portions of the renewable fuels to have various levels of reduced lifecycle greenhouse gas emissions. In contrast, the Oregon Clean Fuels Program would require fuel producers and importers to reduce the lifecycle greenhouse gas emissions from transportation fuel by a specified amount, whether by blending renewable fuels, substituting other low carbon fuels, or using credits from low carbon fuel producers. In addition, the federal Renewable Fuel Standards do not specify where in the United States the renewable fuel volumes are to be consumed – meaning that Oregon is never assured of receiving low carbon fuels under the federal requirement.

2. If the proposal differs from, or is in addition to, applicable federal requirements, explain the reasons for the difference or addition (including as appropriate, the public health, environmental, scientific, economic, technological, administrative or other reasons).

Reducing the lifecycle greenhouse gas emissions from transportation fuel, together with other measures to reduce vehicle tailpipe greenhouse gas emissions and to reduce the number of miles driven in Oregon, is necessary to meet Oregon's greenhouse gas reduction goals as specified in ORS 468A.205. In a 2011 report[1], the Oregon Departments of Transportation, Environmental Quality and Energy, estimated that reduced tailpipe emissions and low carbon fuels could supply 90 percent of the greenhouse gas reductions needed from light duty vehicles by 2035, with the remainder to be made up by reduced miles driven.

[1] *Agencies' Technical Report Responding to Jobs and Transportation Act (2009) Section 37, Part (7) and Chapter 85 Oregon Laws (2010), Section 5*, Oregon Department of Transportation, Oregon Department of Environmental Quality and Oregon Department of Energy, March 1, 2011

Because the Oregon Clean Fuels Program is a performance standard, as opposed to a production mandate like the federal Renewable Fuel Standards, it is designed to encourage innovation. Fuel producers and importers would have an incentive to develop fuels with lower lifecycle emissions and cost. By creating demand for low-carbon fuels, the Oregon Clean Fuels Program would provide the assurance that lower-carbon fuels would be supplied to and consumed in Oregon, along with the commensurate greenhouse gas reductions.

The Oregon Clean Fuels Program is also a key element of Oregon's ten-year energy action plan. The goals of that plan are to:

- Reduce Oregon's dependence on carbon-intensive fuels and foreign oil
- Develop home-grown renewable energy resources
- Mitigate greenhouse gas emissions
- Improve energy efficiency and create rewarding local jobs and
- Boost Oregon's and the nation's economy through investment and innovation

By creating demand for low-carbon fuels and allowing all fuels and all in-state and out-of-state fuel suppliers to compete on an equal lifecycle carbon basis, the Clean Fuels Program supports these goals and will be important to the success of this plan.

3. If the proposal differs from, or is in addition to, applicable federal requirements, did DEQ consider alternatives to the difference or addition? If so, describe the alternatives and the reason(s) they were not pursued.

DEQ considered not moving forward with the Clean Fuels Program and relying instead on the federal Renewable Fuels Standards to reduce greenhouse gas emissions from transportation. This option was rejected because the federal Renewable Fuels Standard would not generate enough emission reductions to meet Oregon's goals.

DEQ also considered not moving forward with the Clean Fuels program and relying instead on Oregon's Low Emission Vehicle Program along with measures to reduce vehicle miles traveled. This option was rejected because lower emitting fuels along with improved vehicle technology and reduced travel are all needed to meet Oregon's greenhouse gas reduction goals.

DEQ considered other options to achieve reductions in lifecycle greenhouse gas emissions from transportation fuel, such as a cap and trade program or a carbon tax. These options were rejected because House Bill 2186, the authorizing statute for this program, only provided authority for the Environmental Quality Commission to "adopt by rule low carbon fuel standards for gasoline, diesel and fuels used as substitutes for gasoline or diesel."

Finally, DEQ considered many options for the design of the Oregon Clean Fuels Program as detailed in the Low Carbon Fuel Standards Advisory Committee Process and Program Design Final Report, Jan. 25, 2011. The report summarizes the options considered and the rationale for the selected options for a number of program design features, including:

- Fuels covered

- Regulated parties
- Exemptions
- Baseline standards for gasoline and diesel
- Compliance schedule
- Emission calculation methodology
- Indirect land use change
- Vehicle drive train efficiency
- Establishing carbon intensity values for fuels
- Use and banking of credits and deficits
- Program deferrals based on fuel supply and price
- Record-keeping and reporting
- Enforcement and
- Program review

Attachment G
Dec. 6-7, 2012, EQC meeting
Page 1 of 2

Oregon Department of Environmental Quality
Chapter 340 Rulemaking

Land Use Evaluation Statement

Rule Caption:
Oregon Clean Fuels Program for Fuel Suppliers and Producers of Transportation Fuels

1. Explain the purpose of the proposed rules.

Climate change poses a serious threat to Oregon's economy, environment and public health. Transportation sources account for approximately one third of all greenhouse gas emissions in Oregon that lead to climate change. The 2009 Oregon Legislature passed House Bill 2186 that authorized the Oregon Environmental Quality Commission to adopt rules that would reduce lifecycle emissions of greenhouse gases from Oregon's transportation fuels by 10 percent over a 10-year period. The proposed rules provide the regulatory framework to implement House Bill 2186, and are now referred to as the Oregon Clean Fuels Program.

The Oregon Clean Fuels Program would be implemented in two phases – Phase 1 would be a reporting phase beginning in 2013, and Phase 2 would be a later greenhouse gas emissions reduction phase. Phase 1 would require Oregon fuel producers and importers to register, keep records and report the volumes and carbon intensities of the fuels they provide in Oregon. Phase 2 would require regulated parties to reduce the average carbon intensity of gasoline and diesel fuel they provide in Oregon each year to meet the clean fuel standard for that year. Regulated parties could select the strategy that works best for them to meet the requirement, such as providing more biofuels, natural gas or electricity, or by purchasing clean fuel credits from suppliers of lower-carbon fuels.

Phase 1 is intended to provide DEQ and regulated parties time to fully develop record-keeping and reporting protocols and systems. It would also allow DEQ to gather data about Oregon's transportation fuels that will help inform DEQ and decision makers about the feasibility of moving ahead with the next phase of the program. If DEQ recommends moving forward to propose Phase 2 of the program, DEQ would initiate a new rulemaking process, including new advisory committees to gather new input on the design of the Phase 2 rules and it's fiscal and economic impact. Phase 2 can only be implemented if:

- The Oregon Legislature adopts a bill to remove the statutory 2015 sunset that currently applies to the Oregon Clean Fuels Program; and
- The Oregon Environmental Quality Commission adopts rules to remove a regulatory

deferral of Phase 2 of the Oregon Clean Fuels Program.

2. **Do the proposed rules affect existing rules, programs or activities that are considered land use programs in the DEQ State Agency Coordination Program?**

   Yes___ No__X_

   a. **If yes, identify existing program/rule/activity:**
      Not applicable.

   b. **If yes, do the existing statewide goal compliance and local plan compatibility procedures adequately cover the proposed rules?**
      Not applicable.

   c. **If no, state if the proposed rules are considered programs affecting land use. State the criteria and reasons for the determination.**

      The proposed rules for the Oregon Clean Fuels Program are not expected to have significant effects on resources, objectives or areas identified in the statewide planning goals, nor present or future land uses identified in acknowledged comprehensive plans.

      However, while the proposed rules do not directly affect land use, they further the objective of Goal 6 to protect air quality by reducing the emissions of greenhouse gases. They also further the objective of Goal 13 to conserve energy by requiring greater use of lower carbon, or less energy-intense, fuels.

3. **If the proposed rules have been determined a land use program under question two above, but are not subject to existing land use compliance and compatibility procedures, explain the new procedures DEQ will use to ensure compliance and compatibility**.

   Not applicable.

Final Report

HB 2186 Update Report to the 2013 Legislature

Oregon Low Carbon Fuel Standards

Advisory Committee Process and Program Design

January 25, 2011

State of Oregon Department of Environmental Quality

Last Updated: 1/25/2011
By: Sue Langston
11-AQ-004

This report prepared by:

Oregon Department of Environmental Quality
811 SW 6th Avenue
Portland, OR 97204
1-800-452-4011
www.oregon.gov/deq

Contact:
David Collier
(503) 229-5177

Principal Authors:
Sue Langston
David Collier
Cory Ann Wind
Dave Nordberg
Carrie Ann Capp
Wendy Simons

GREET Modeling:
Svetlana Lazarev
Wes Risher

Principal contributors:
Vijay Satyal, Oregon Department of Energy
Rick Wallace, Oregon Department of Energy

TABLE OF CONTENTS

I. Executive Summary 8

II. Oregon Low Carbon Fuel Program: At A Glance 10

III. House Bill 2186 Roadmap 37

IV. Background 40

1. Overview of the Oregon Low Carbon Fuel Standards ... 40
2. Oregon's Fuels ... 41
3. Low Carbon Fuel Standards in Other Areas and Other Related Programs ... 44
   A. Low Carbon Fuel Standards ... 44
   B. Other Related Programs ... 45

V. Oregon Low Carbon Fuel Standards Development Process 47

1. Advisory Committee Process ... 47
   A. Introduction ... 47
   B. Rulemaking process ... 47
   C. Advisory Committee Process ... 47
   D. Policy Issues for the Advisory Committee to Address ... 49
   E. DEQ Contractors ... 50
2. Oregon Interagency Collaboration Process ... 50
3. Stakeholder meetings ... 51
4. Coordination with Other Low Carbon Fuel Standards Work ... 51
   A. Washington State ... 51
   B. California ... 52
   C. Northeast and Mid-Atlantic States ... 52
   D. British Columbia ... 52

VI. Low Carbon Fuel Standards Program Design 53

1. Covered Fuels ... 53
   A. Regulated Fuels ... 54
   B. Opt-in Fuels ... 54
2. Regulated and Opt-in Parties ... 56
   A. Gasoline, Diesel, Biomass-based Diesel and Ethanol ... 57
   B. Compressed Natural Gas (CNG) from Fossil Sources ... 59
   C. Liquefied Natural Gas (LNG) from Fossil Sources ... 60
   D. Biogas (CNG or LNG derived from Biogas) ... 62
   E. Hydrogen ... 63
   F. Electricity ... 63
3. Exemptions ... 66
   A. Exemptions for Fuel Used in Specific Applications ... 66
   C. Exemptions for Specific Alternative Fuels ... 67
   D. Reporting Exempt Fuels ... 68
4. Setting the Baseline Standards ... 69
5. Low Carbon Fuel Standards Compliance Schedule ... 72

Fuel Carbon Intensity Lookup Table 76
6. Updating or Adding to the Carbon Intensity Lookup Table 78
A. Updating Existing Statewide Average Carbon Intensities in Lookup Table 79
B. Adding a New Carbon Intensity to the Lookup Table (New Fuel Pathways Process) 79
C. High Carbon Intensity Crudes 82
7. Credits and Deficits 83
A. Introduction 83
B. Overview of How to Calculate Credits and Deficits 85
C. Program Elements 87
8. Buying and Selling Credits 91
9. Fuel Supply Deferrals 93
A. Process for issuing Fuel Supply Deferrals 94
B. Compliance Adjustment Options for Fuel Supply Deferrals 97
10. Consumer Cost Safety Net 101
11. Implementation Issues 108
A. Use of Biodiesel and Renewable Diesel 108
B. Storage and Distribution of Low Carbon Fuels 108
C. Recordkeeping and Reporting 109
D. Enforcement 112
E. Standards, Specifications, Testing Requirements to Ensure Quality of Fuels 113
F. Safety of Alternative Fuels 113
12. Review of Rule 117
13. Flexible Implementation Approaches to Minimize Compliance Cost 119
14. Effect of the Sunset 120
A. Implementation and Enforcement 121
B. In-State Biofuels Production 121
C. Low Carbon Fuel Credits 121
D. Electric Vehicle Infrastructure 121
VII. Calculating Carbon Intensities for Oregon Transportation Fuels 122
1. Direct Lifecycle Analysis 123
A. Overview 123
B. Calculation Methodology for Carbon Intensity of Oregon's Fuels 124
C. Lifecycle Analysis for Fuel Made from Waste 128
D. Lifecycle Analysis for Fuels Made from Biomass versus Fuels Made from Petroleum Products 129
E. Models Used on Lifecycle Analysis 129
2. Indirect Land Use Change and Other Indirect Effects 135
A. Indirect Land Use Change 135
B. Other Indirect Effects 138
3. Energy Economy Ratios (EERS) and Drive Train Efficiencies 139
VIII. Compliance Scenarios and Economic Analysis 145
1. Introduction 145

2. Biomass Assessment 146
3. Fuels Assessment Discussion Paper 147
4. Calculate Carbon Intensities 149
5. Compliance Scenarios 149
6. Economic Analysis 152
A. How were the Economic Impacts Analyzed? 153
B. Economic Analysis Results 153
C. Cost Effectiveness 155
IX. Potential Impacts to Public Health and the Environment 157
1. Criteria Pollutants 157
2. Air Toxics 159
3. Effect of Burning more Ethanol 162
4. Effect from Burning more Biodiesel 162
5. Electricity Produced in Oregon 163
6. Other Environmental Impacts 163
7. Net Reduction in Greenhouse Gas Emissions 164
X. Annotated Version of House Bill 2186, Sections 6-9 165
XI. Advisory Committee Member List and Operating Principles 168
1. Low Carbon Fuel Advisory Committee Member List 168
2. Advisory Committee Operating Principles 168
A. Purpose 169
B. Low Carbon Fuel Advisory Committee Charge 169
C. Low Carbon Fuel Advisory Process and Operating Principles 170
D. Public Involvement 171
E. Process Support 171
F. Communications and Media Coverage: 171

Appendices

Appendix A: Summary of Advisory Committee Input
Appendix B: Lifecycle Analysis
Appendix C: Infrastructure Cost Assumptions Memorandum
Appendix D: Economic Analysis
Appendix E: Comparable Economic Studies in Other States Memorandum
Appendix F: Compliance Scenario Documentation
Appendix G: Indirect Land Use Change Comparative Analysis
Appendix H: Fuels Assessment Discussion Paper
Appendix I: Biomass Assessment
Appendix J: Credit and Deficit Calculations
Appendix K: Review of Biodiesel and Renewable Diesel Use Considerations

FIGURES

Figure 1: Oregon's Petroleum Imports 42
Figure 2: Supply Chain of Gasoline 56
Figure 3: LNG Pathways, Carbon Intensity, and Opt-in/Regulated Parties 61
Figure 4: Low Carbon Fuel Standards Compliance Schedule for Gasoline and Gasoline Substitutes 73
Figure 5: Low Carbon Fuel Standards Compliance Schedule for Diesel and Diesel Substitutes 74
Figure 6: Adding a Carbon Intensity to the Lookup Table 81
Figure 7: Generation of Low Carbon Fuel Deficits 84
Figure 8: Generation of Low Carbon Fuel Credits 85
Figure 9: Temporary Fuel Supply Deferrals 100
Figure 10: Forecasted Fuel Supply Deferrals 100
Figure 11: 12-Month Rolling Weighted Average Retail Gasoline Prices: Oregon and Statutory PADD-5: April 2000 to July 2009 104
Figure 12: Percent Difference: Statutory PADD-5 and Oregon 12-month Rolling Weighted Average Retail Price of Gasoline: April 2000 to July 2009 105
Figure 13: 12-Month Rolling Weighted Average Retail No. 2 Diesel Prices: Oregon and PADD-5. *April 2000 to July 2009* 106
Figure 14: Percent Difference Between the 12-month Weighted Average Diesel Price in PADD-5 and OR. *April 2000 to June 2009* 107
Figure 15: Process Flow Diagram for Ethanol Production from Corn 124
Figure 16: CNG Pathways and Carbon Intensity 125
Figure 17: LNG Pathways, Carbon Intensity, and Opt-in/Regulated Parties 126
Figure 18: Example Lifecycle Analysis for Fuel Made from Waste 128
Figure 19: GREET Fuel Production Pathways 130
Figure 20: Oregon Petroleum Pathways 131
Figure 21: Ethanol Pathways 133
Figure 22: Comparison of Indirect Land Use Change Results 136
Figure 23: Vehicle Distance Traveled 140
Figure 24: Economic Analysis Process Flowchart 146
Figure 26: Household Fuel Spending vs. Business as Usual 155
Figure 25: Impact on Oregon's Employment 154

TABLES

Table 1: Summary of Low Carbon Fuel Standards Proposals and Program Design 10
Table 2: House Bill 2186 Roadmap 37
Table 3: Oregon Distillate Consumption 43
Table 4: Summary of Regulated and Opt-in Parties 64
Table 5: Low Carbon Fuel Standards Compliance Schedule for Gasoline and Gasoline Substitutes 73
Table 6: Low Carbon Fuel Standards Compliance Schedule for Diesel and Diesel Substitutes 74
Table 7: Carbon Intensity Lookup Table for Gasoline and Gasoline Substitutes 77
Table 8: Carbon Intensity Lookup Table for Diesel and Diesel Substitutes 78
Table 9: Scope of Review for the Low Carbon Fuel Standard 117
Table 10: Comparison of Direct and Indirect Carbon Intensity Values 137
Table 11: EER Values for Fuels Used in Light-Duty Applications 142
Table 12: EER Values for Fuels Used in Heavy-Duty Applications 142
Table 13: California Air Resources Board Methodology for Calculating Energy Economy Ratios 143
Table 14: Low Carbon Fuel Advisory Committee Member List 168

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 pursed 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.

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.

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.

Low carbon fuel standards will produce significant economic benefits for Oregon, creating new jobs and personal income that stays and circulates within this state.

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.

DEQ's objective is to design a low carbon fuel standards program that is consistent with HB2186, effective in reducing greenhouse gas emissions, flexible for regulated parties, realistic, achievable, and reflects the best approach for Oregon.

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

1) Covered Fuels and Regulated/Opt-in Fuels	
1a) Covered Fuels *(See page 53 For details)*	
DEQ Proposal	• Diesel • Hydrogen • CNG and LNG from fossil sources • Gasoline • Ethanol • CNG and LNG from biogas • Electricity • Biomass-based diesel • Any other fuel used for transportation purposes not specifically excluded or exempt from the low carbon fuel standards (This is a placeholder for future fuels that might be developed) Fuels used for transportation includes off-road fuel. Not covered: Propane
Alternatives Considered	Advisory committee members requested that propane be included as opt-in to the low carbon fuel standard. *Arguments in favor — 1) Propane could assist regulated parties in meeting the low carbon fuel standards.*
Rationale	House Bill 2186 specifically authorizes the exemption of propane from the low carbon fuel standards.
1b) Regulated and Opt-in Fuels *(See page 54 for details)*	
DEQ Proposal	**Regulated (compulsory participants) under low carbon fuel standards:** • Gasoline • Biomass-based diesel • Any other liquid or non-liquid fuel not otherwise exempt from low carbon fuel standards or specified as an opt-in fuel • Diesel • Biomass-based diesel blends • Fossil LNG that is not made from natural gas supplied through a North American pipeline • Ethanol • Ethanol blends **Opt-In under low carbon fuel standards** (can choose to opt-in to all requirements to generate credits for sale)**:** • Compressed or liquefied hydrogen • Hydrogen fuel blend • Fossil LNG produced from natural gas supplied through a North American pipeline • Biogas LNG • Electricity

Alternatives Considered	• Biogas CNG • Fossil CNG
	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	Alternative 1: 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.* 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	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)*	
DEQ Proposal	**Opt in fuel. Opt-in party:** Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon. **Transfer of credits with sale of fuel:** Transfer only occurs if seller and buyer agree.

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	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.
2c) Liquefied Natural Gas (LNG) from fossil sources *(See page 60 for details)*	
DEQ Proposal	**Opt-in:** Any LNG produced from natural gas supplied through a North American pipeline. **Regulated:** all other LNG **Opt-in or Regulated party:** Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon
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	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.
2d) Biogas (CNG or LNG) *(See page 62 for details)*	
DEQ Proposal	**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. **Transfer of credits with sale of fuel:** Transfer only occurs if seller and buyer agree.
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	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 *Rationale*	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	Alternative 1: Exempting 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.* Alternative 2: Oregon's renewable fuel standard exemptions. *Arguments in favor — 1) Consistency.* Alternative 3: Exemption for 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 LCFS.* Alternative 4: Short line rail should not be exempt. *Arguments in favor — 1) The switch to cleaner fuels requires a one-time education effort, and a one-time educational effort should not a barrier to participation in the low carbon fuel standards.* Alternative 5: *No industry exemptions. Arguments in favor — 1) exemptions perpetuate the myth that biofuels are problematic.*
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)*	
DEQ Proposal	• **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.
Rationale	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

	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 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.

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 could 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 which 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	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 with the statute to use statewide averages of carbon intensity for some fuels. 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. 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.

6b) Co-product credits *(See page 123 for details)*	
DEQ Proposal	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.
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 double counting.*
Rationale	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.
6c) Lifecycle analysis for fuel made from waste *(See page 128 for details)*	
DEQ Proposal	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.
Rationale	This is consistent with how DEQ's Solid Waste program views waste versus a feedstock.
6d) Lifecycle analysis for fuels made from biomass versus fuels made from petroleum products *(See page 129 for details)*	
DEQ Proposal	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.
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.*
Rationale	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.
6e) Models used on lifecycle analysis *(See page 129 for details)*	
DEQ Proposal	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.
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	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 TIAX 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*
Rationale	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)*	
DEQ Proposal & Rationale	• 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 *(See page 87 for details)*	
DEQ Proposal	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.
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 *(See page 88 for details)*	
DEQ Proposal	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.
Rationale	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.
8c) How would fuel sold to exempt users be excluded from credit and deficit calculations? *(See page 89 for details)*	
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.

	• Exclude none of that 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)*	
DEQ Proposal	Yes. Credits can accrue during exemption or deferral periods.
Alternatives Considered	Alternative 1: Credits cannot accrue during deferral periods.
Rationale	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. Allowing credits to accrue during times of exemptions or deferrals provides more regulatory certainty for investors in low carbon fuels.
8e) Buying and Selling Credits *(See page 91 for details)*	
DEQ Proposal	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. DEQ will maintain a list of regulated and opt-in parties, and for fuel producers, the total credit generation capacity of each production plant. 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. DEQ will not take enforcement action against the credit buyer, provided they had verified: 1. That the credit seller was on DEQ's regulated/opt-in party list, 2. The carbon intensity of the fuel from that producer matches the carbon intensity for that fuel producer on DEQ's website; and 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. Credits would not be verified by DEQ prior to sale.
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) 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.*
Rationale	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 are 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.
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 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.*
Rationale	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.
10b) Compliance Adjustments for Forecasted Fuel Supply Deferral *(See page 99 for details)*	
DEQ Proposal	When issuing a forecasted deferral, DEQ will have two deferral types to choose from: **Forecasted Fuel Supply Deferral Type 1:** Administratively defer the standard for one week to a year (no rulemaking, administrative only, no lasting change to compliance curve or horizon year). **Forecasted Fuel Supply Deferral Type 2:** 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.

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	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)*

DEQ Proposal	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[i] 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. 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.
Rationale	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)*	
DEQ Proposal	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. 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)

	Revision to physical fuel route report (as needed) • Revisions to physical fuel route report when conditions change. Annual report • 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. Regulated or opt-in parties submitting reports might request information be exempt from disclosure under ORS 192.410-505.
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: 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.*
Rationale	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.
14) Review of Rule *(See page 117 for details)*	
DEQ Proposal	• **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

	key program elements and submit a report to the Environmental Quality Commission. 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	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.*
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 2: House Bill 2186 Roadmap

House Bill 2186 reference	Program element required by statute	Relevant Report Section	Page Number
Section 6 (2)(b)(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	VI. 5. Low Carbon Fuel Standards Compliance Schedule	**Page 72**
Section 6 (2)(b)(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	VI. 5. Low Carbon Fuel Standards Compliance Schedule VII. Calculating Carbon Intensities for Oregon Transportation Fuels	**Page 72** **Page 122**
Section 6 (2)(b)(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;	VI. 1. Covered Fuels	**Page 53**
Section 6 (2)(b)(D)	Standards for the issuance of deferrals, established with adequate lead time, as necessary to ensure adequate fuel supplies	VI. 9. Fuel Supply Deferrals	**Page 93**
Section 6 (2)(b)(E)	Exemptions for liquefied petroleum gas and other alternative fuels that are used in volumes below thresholds established by the Environmental Quality Commission;	VI. 3. Exemptions	**Page 66**
Section 6 (2)(b)(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	VI. 11. E. Standards, Specifications, Testing Requirements to Ensure Quality of Fuels	**Page 113**

House Bill 2186 reference	Program element required by statute	Relevant Report Section	Page Number
Section 6 (2)(b)(G)	Adjustments to the amounts of greenhouse gas emissions per unit of fuel energy assigned to fuels for combustion and drive train efficiency	VII. 3. Energy Economy Ratios (EERs) and Drive Train Efficiencies	**Page 139**
Section 6 (2)(c)	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	IV. 3. Low Carbon Fuel Standards in Other Areas and Other Related Programs	**Page 44**
Section 6 (2)(d)	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	VI. 10. Consumer Cost Safety Net	**Page 101**
Section 6 (3)(a)	Safety	VI. 11. F. Safety	**Page 113**
Section 6 (3)(a)	Feasibility	VIII. Compliance Scenarios and Economic Analysis	**Page 145**
Section 6 (3)(a)	Net reduction of greenhouse gas emissions	IX. 7. Net Reduction in Greenhouse Gas Emissions	**Page 164**
Section 6 (3)(a)	Cost-effectiveness	VIII. 6. Economic Analysis C. Cost Effectiveness	**Page 152**
Section 6 (3)(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	IX. Potential Impacts to Public Health and the Environment	**Page 155**

House Bill 2186 reference	Program element required by statute	Relevant Report Section	Page Number
Section 6 (3)(c)	Flexible implementation approaches to minimize compliance costs	VI. 13. Flexible Implementation Approaches to Minimize Compliance Cost	**Page 119**
Section 6 (3)(d)	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	Appendix D: Economic Analysis Appendix E: Comparable Economic Studies in Other States	**Appendix D** **Appendix E**
Section 6 (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	VI. 3. Exemptions	**Page 66**

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 gasses which in turn cause the temperature of the atmosphere to rise – global warming. The amount of greenhouse gasses created by combustion varies depending on the fuel being combusted. Therefore, the degree of global warming caused by the greenhouse gasses 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.

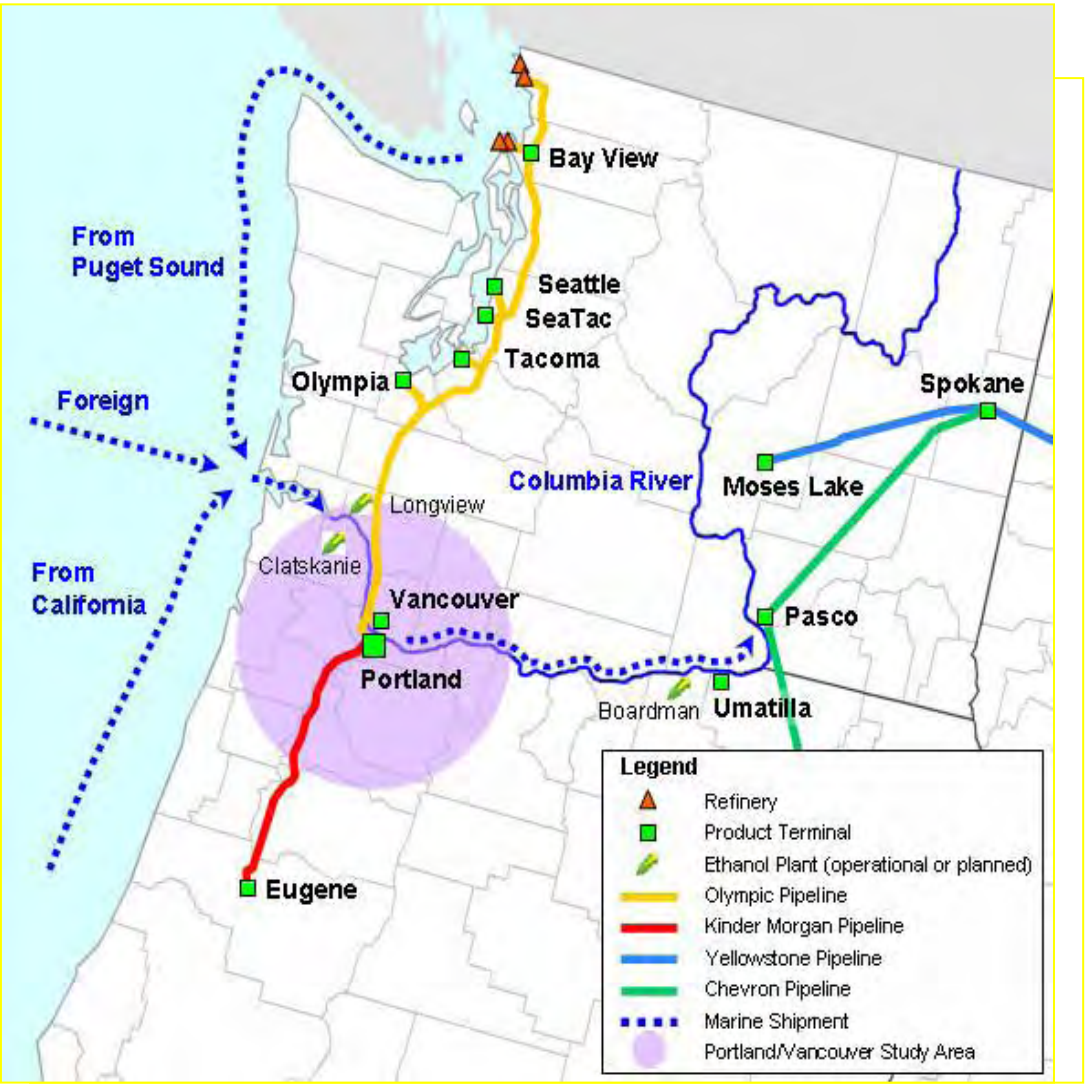
2. Oregon's Fuels

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



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

Oregon Distillate Consumption (773 Million Gallons Distillate Total 2007 (EIA))	
Residential	22,453,000 gallons
Commercial	18,965,000 gallons
Industrial	18,191,000 gallons
Farm	26,846,000 gallons
Electric Power	1,400,000 gallons
Railroad	80,362,000 gallons
Vessel Bunkering	20,003,000 gallons
On-Highway	560,598,000 gallons
Military	1,977,000 gallons
Off-Highway	22,367,000 gallons

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"[2]) 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"[3])

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.

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

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

consensus. 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 Bill2186 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.

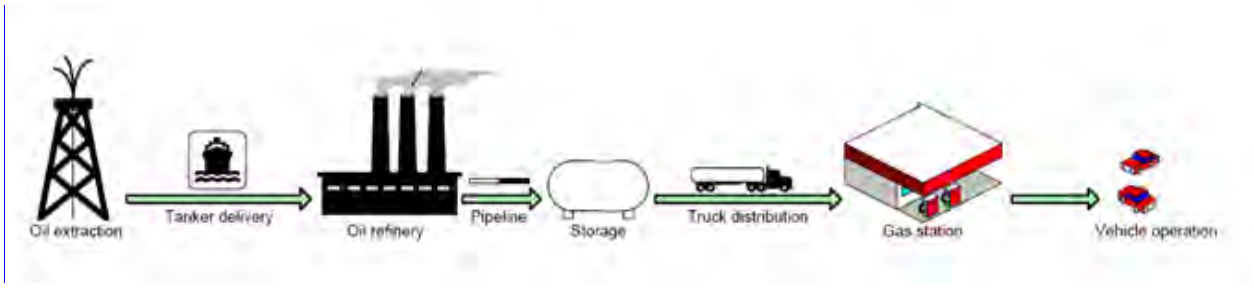
Advisory committee input on this issue can be found in Appendix A.

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



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.

<u>Alternatives considered</u>

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 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.

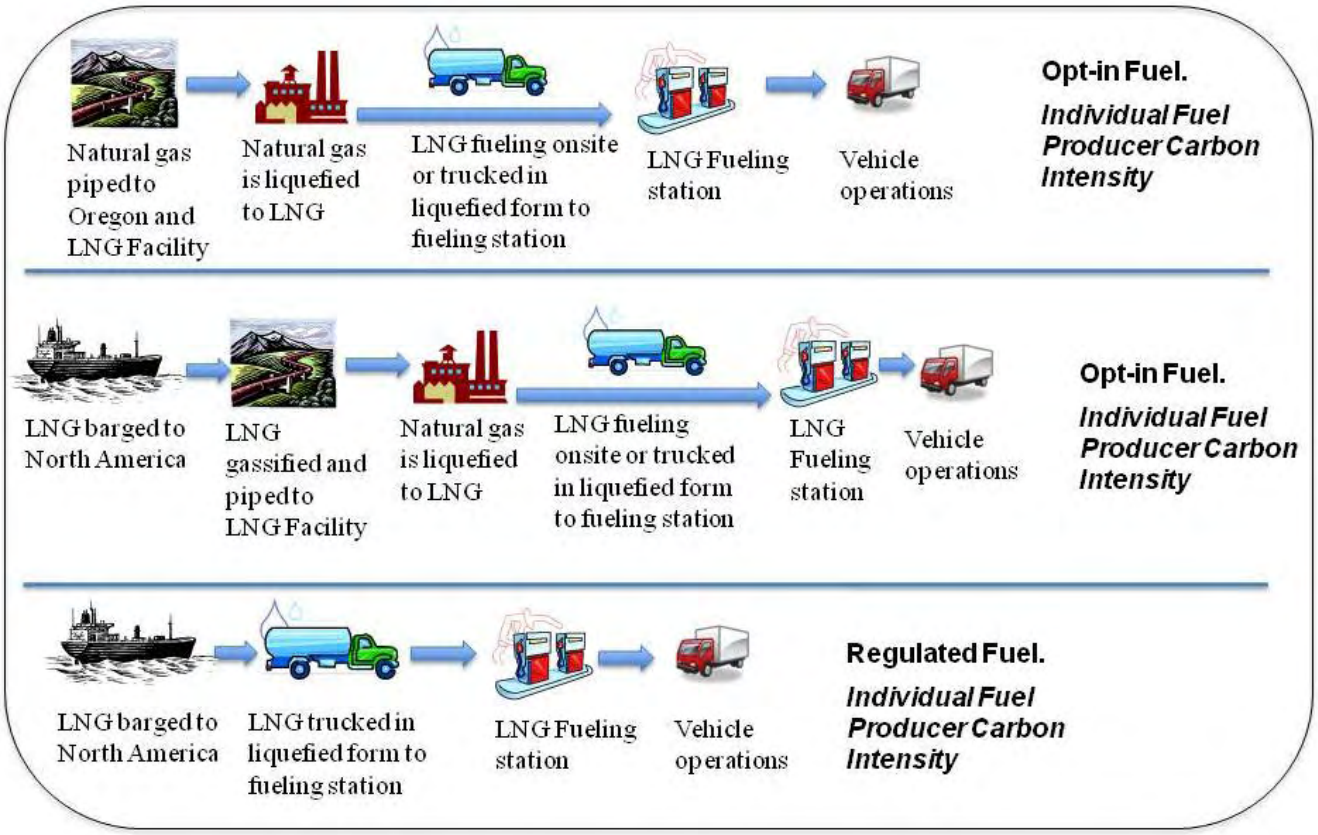
Regulated: Any LNG that is not derived from natural gas supplied from a natural gas pipeline. This includes LNG that is brought to Oregon in liquefied form and delivered in liquefied form to a fueling facility. See **Figure 3** on page 61.

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

Fuel	Regulated or Opt-In?	Regulated Party	Point of regulation	Transfer of compliance obligation or credits

Fuel	Regulated or Opt-In?	Regulated Party	Point of regulation	Transfer of compliance obligation or credits
Gasoline, Diesel, Biomass-based diesel, and Ethanol	Regulated	Producer, Oregon Large Importer, or Oregon Small Importer of the fuel	Point at which fuel is produced in Oregon or imported into Oregon	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.
Compressed Natural Gas (fossil sources)	Opt-in	Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon	Point at which the fuel is dispensed for transportation use	Transfer only occurs if both transferor and recipient agree.
Liquefied Natural Gas (fossil sources)	Opt-in: any LNG produced from natural gas supplied through a pipeline Regulated: all other LNG	Utility company, energy service provider, or other entity that owns the fuel dispensing equipment in Oregon	Point at which the fuel is dispensed for transportation use	Transfer only occurs if both transferor and recipient agree.
Biogas CNG, Biogas LNG	Opt-in	Producer or Oregon importer	Point at which the fuel is produced in Oregon or imported into Oregon	Transfer only occurs if both transferor and recipient agree.
Hydrogen	Opt-in	Person who owns the fuel at the time the finished fuel is made or imported into Oregon	Point at which finished fuel is first manufactured or imported into Oregon	Transfer only occurs if both transferor and recipient agree.
Electricity	Opt-in	Opt-in priority: 1. Bundled services provider 2. Electricity provider, 3. Owner and operator of electric charging equipment (including homeowners).	Point at which electricity is dispensed for transportation use.	None.

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 gallons equivalent. 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.[ii] 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.*

<u>Alternatives considered</u>

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.*

[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 4: Use Oregon Renewable Fuel Standard exemptions. *Arguments in favor — 1) Consistency.*

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.*

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 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.

House Bill 2186

SECTION 6. (2) (b) (b) The commission may adopt the following related to the standards, including but not limited to:

(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;

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

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

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

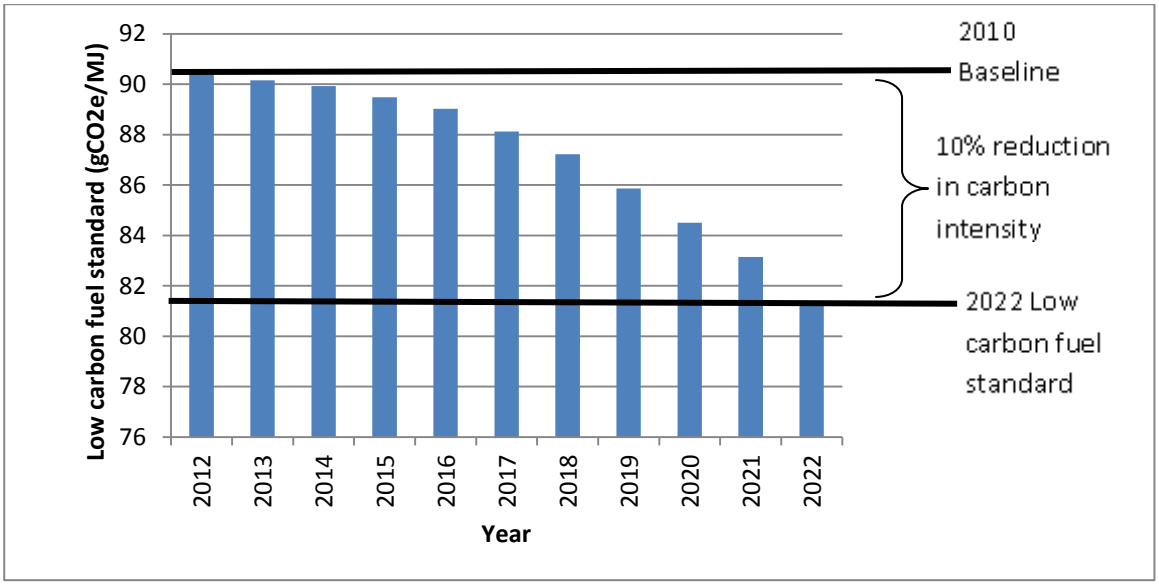
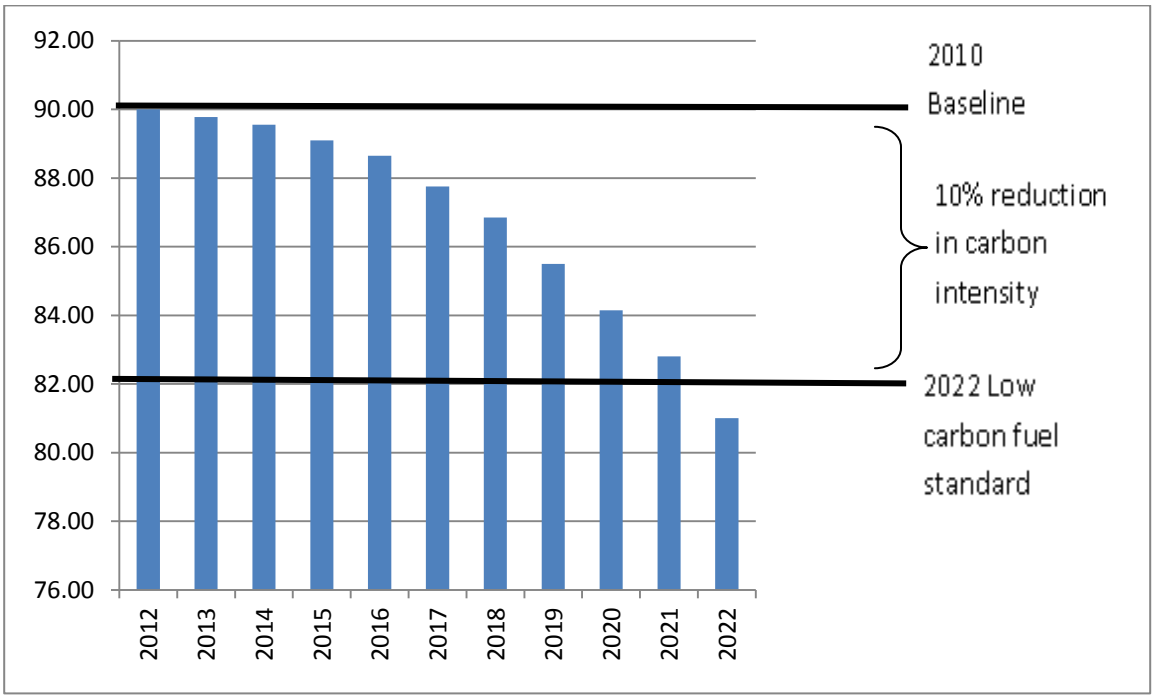


Table 6: Low Carbon Fuel Standards Compliance Schedule for Diesel and Diesel Substitutes

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

Figure 5: Low Carbon Fuel Standards Compliance Schedule for Diesel and Diesel Substitutes



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.

<u>Alternatives considered</u>

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 7: Carbon Intensity Lookup Table for Gasoline and Gasoline Substitutes

Fuel	Pathway Description	Carbon Intensity Values (gCO2e/MJ[1])			
		Direct Emissions	Land Use Change or Other Indirect Effect[2]	EER[3] Applied	Final
Gasoline	Based on a weighted average of gasoline supplied to Oregon	92.34	TBA	1	92.34
Ethanol from Corn	Ethanol produced in the Midwest from MW grown corn. MW Average production[4], GREET Default.	64.82	TBA	1	64.82
	NW production, MW Corn. Dry Mill, NG[5], Wet DGS[6]	53.79	TBA	1	53.79
Ethanol from Sugarcane	GREET defaults except transportation	26.44	TBA	1	26.44
Cellulosic Ethanol	NW Farmed Trees	15.54	TBA	1	15.54
	Wheat Straw	20.90	TBA	1	20.90
	Forest Residue GREET Defaults for gasification	20.49	TBA	1	20.49
	Mill Waste	12.31	TBA	1	12.31
Compressed Natural Gas (CNG)	North American natural gas delivered via pipeline; compressed in OR	70.22	TBA	1	70.22
Electricity	Oregon average electricity mix 2012	154.98	TBA	4.1	37.80
	Oregon average electricity mix 2013	154.98	TBA	4.0	38.74
	Oregon average electricity mix 2014	154.98	TBA	3.9	39.73
	Oregon average electricity mix 2015	154.98	TBA	3.8	40.78
	Oregon average electricity mix 2016	154.98	TBA	3.7	41.88
	Oregon average electricity mix 2017	154.98	TBA	3.6	43.00
	Oregon average electricity mix 2018	154.98	TBA	3.5	44.28
	Oregon average electricity mix 2019	154.98	TBA	3.4	45.58
	Oregon average electricity mix 2020	154.98	TBA	3.3	46.96
	Oregon average electricity mix 2021	154.98	TBA	3.2	48.43
	Oregon average electricity mix 2022	154.98	TBA	3.1	49.99

[i] gCO2e/MJ means grams of carbon dioxide equivalent per mega joule

[2] 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.

[3] EER means Energy Economy Ratio

[4] Midwest average refers to the source of electricity used to refine the fuel

[5] NG refers to the energy source used to refine the fuel

[6] 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

Fuel	Pathway Description	Carbon Intensity Values (gCO2e/MJ[1])			
		Direct Emissions	Land Use Change or Other Indirect Effect[2]	EER[3] Applied	Final
Ultra Low Sulfur Diesel	Based on a weighted average of diesel supplied to Oregon	91.53	TBA	1	91.53
Renewable Diesel	Northwest Production, Midwest soy oil	21.66	TBA	1	21.66
Biodiesel	Midwest Soybeans. GREET default Midwest Average[4] production, biodiesel shipped by rail to Oregon	19.99	TBA	1	19.99
	Northwest Canola	27.31	TBA	1	27.31
	Yellow Grease Average.	10.28	TBA	1	10.28
	Tallow Average	16.85	TBA	1	16.85
Compressed Natural Gas (CNG)	Pipeline NG compressed to CNG at the refueling stations	70.22	TBA	0.94	74.70
Electricity	Oregon average electricity mix	154.98	TBA	2.70	57.4

[i] gCO2e/MJ means grams of carbon dioxide equivalent per mega joule

[2] 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.

[3] EER means Energy Economy Ratio

[4] 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:

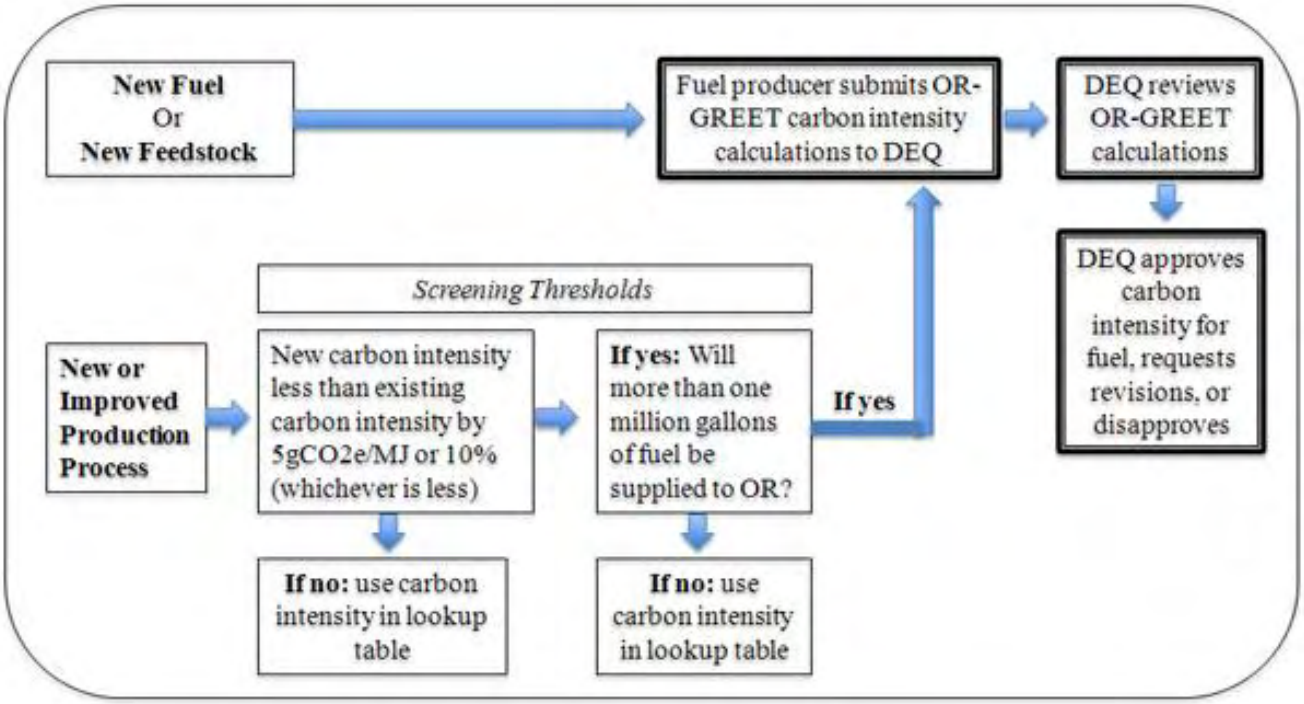
a) **Minimum Thresholds for Changes in Carbon Intensity:** The well-to-tank carbon intensity of the new process, compared to the existing process for the same fuel-feedstock combination in the lookup table, changes more than 5.0 g CO2E/MJ or 10 percent, whichever is less; **AND**

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.

Figure 6: Adding a Carbon Intensity to the Lookup Table



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***.

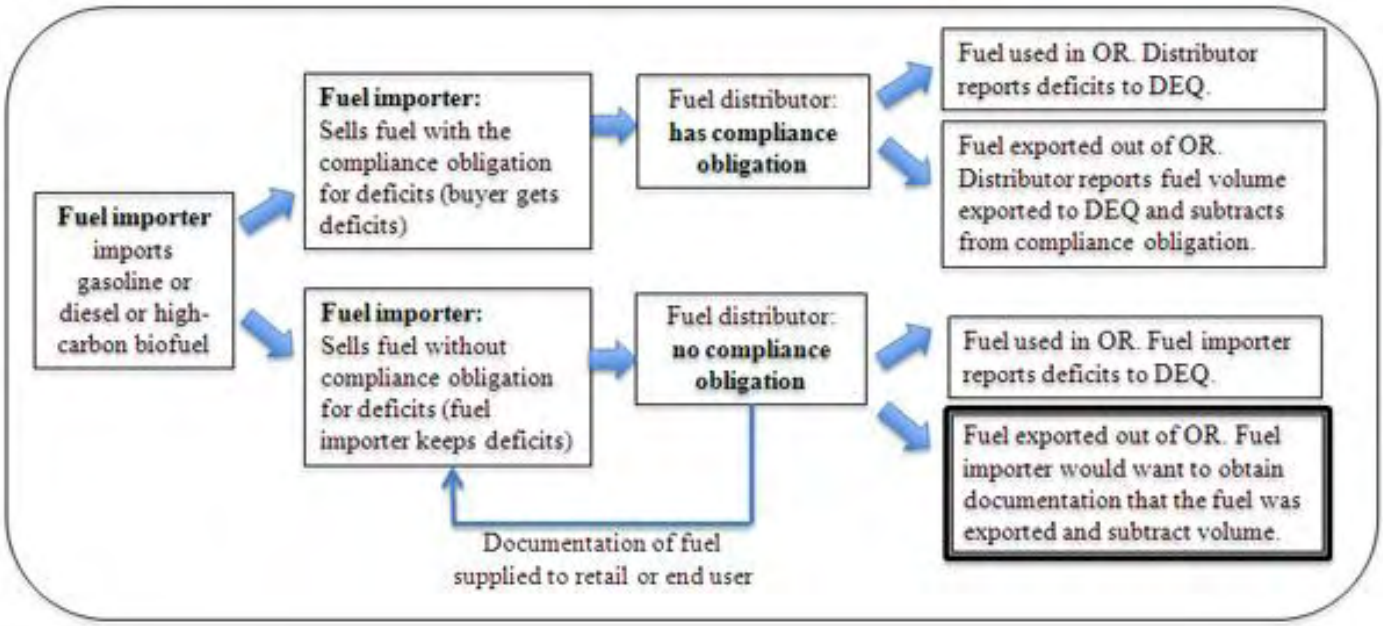
i. Generation of Deficits

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

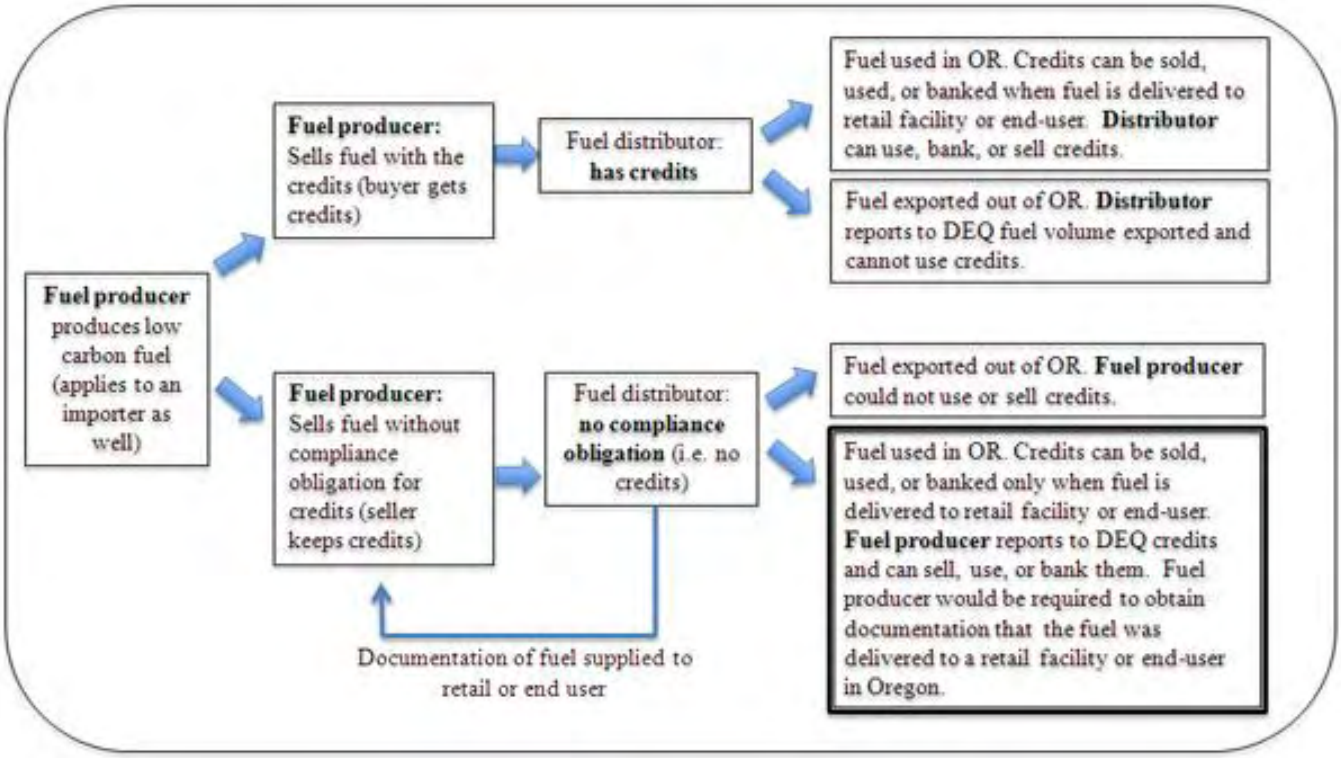
Credits can be sold, banked, or used once the fuel is used or supplied to a retail facility or end user. The opt-in or regulated party reporting a credit would need to possess documentation that the fuel was:

- 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.

Figure 8: Generation of Low Carbon Fuel Credits



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 feet[iii] (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 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 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 CO_2 equivalent, while in the next step emissions are converted into metric tons of CO_2 equivalent. CO_2 equivalent, or CO_2E, 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 climate change potential.

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.

[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:

	Carbon Intensity (gCO2e/MJ)	**Percent of Total Carbon Intensity**
Direct Carbon Intensity	64.82	80 percent
Indirect Carbon Intensity	16.00	20 percent
Total	80.82	100

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.

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;

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.

<u>Alternatives considered</u>

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 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 *Forecasted* 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

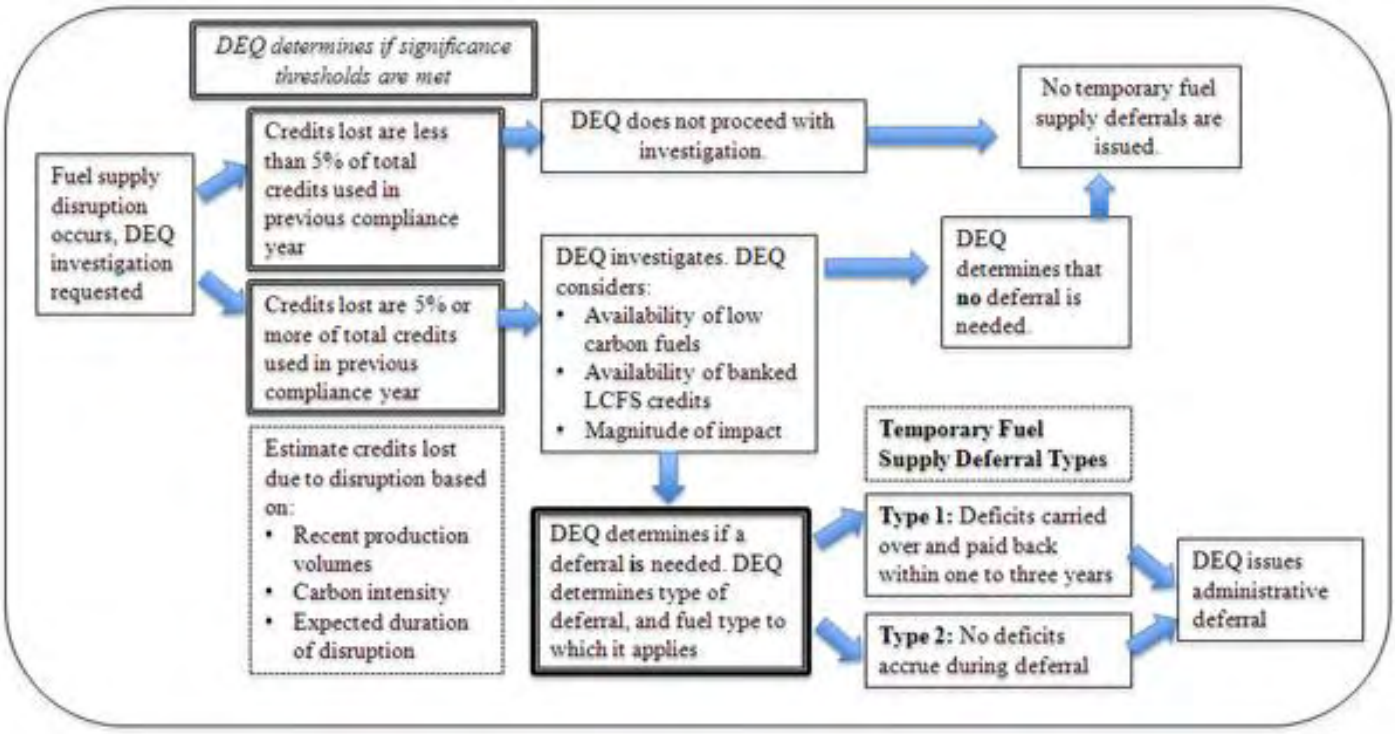
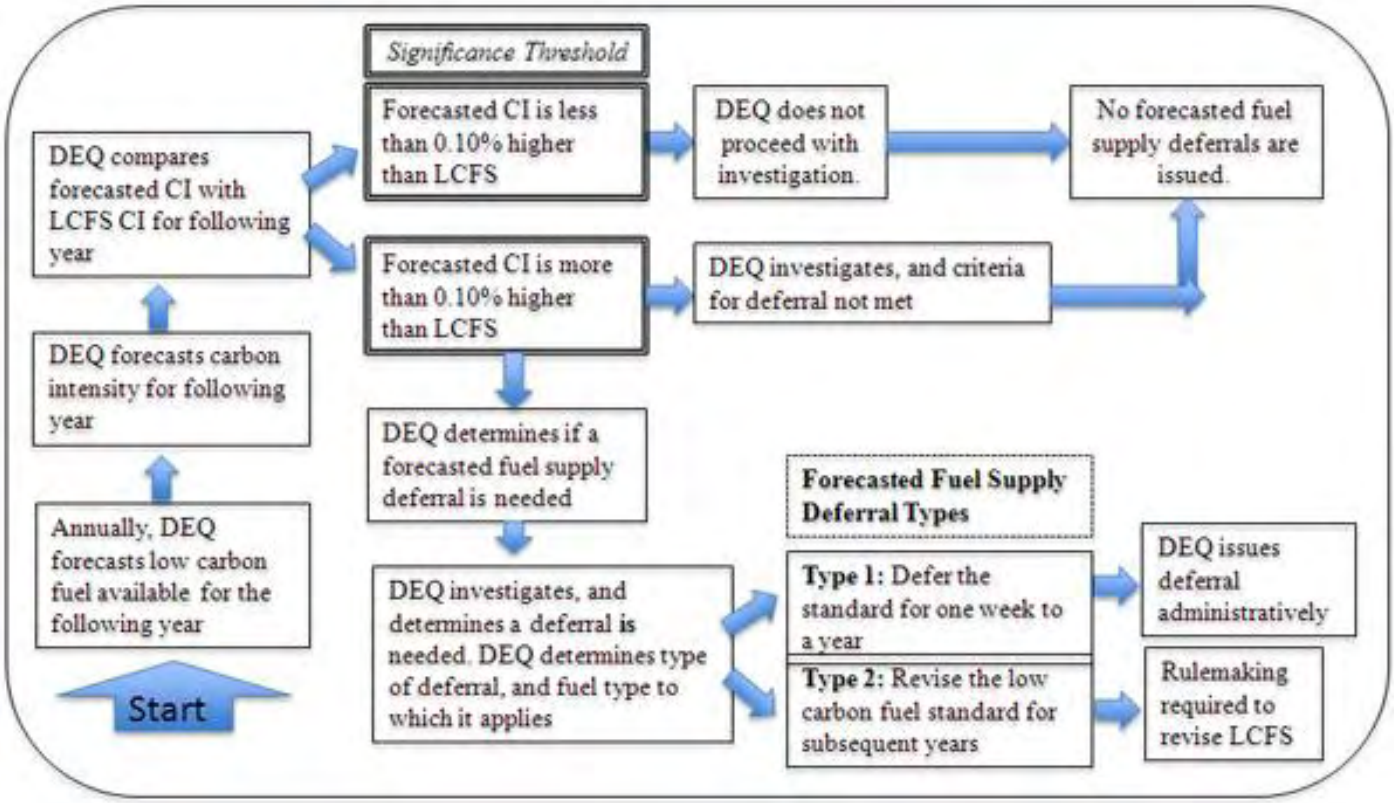


Figure 10: Forecasted Fuel Supply Deferrals



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

HB 2186

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:
(d) "PADD 5 region" means the Petroleum Administration for Defense District 5 states of Arizona, Nevada, Oregon and Washington.

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);

[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

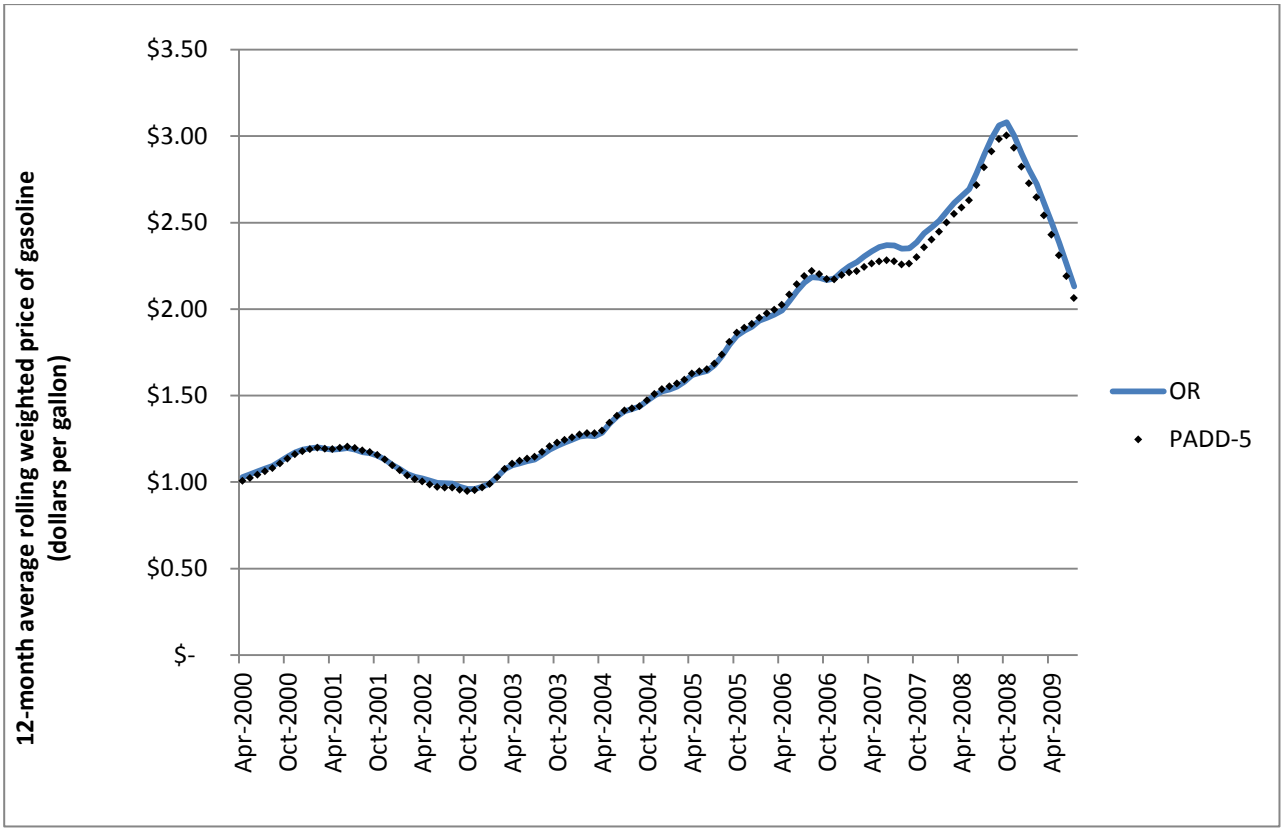
Proposed definition of "non-competitive" for gasoline and diesel. The definition of non-competitive is important because it will determine when an investigation into a price difference is

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).

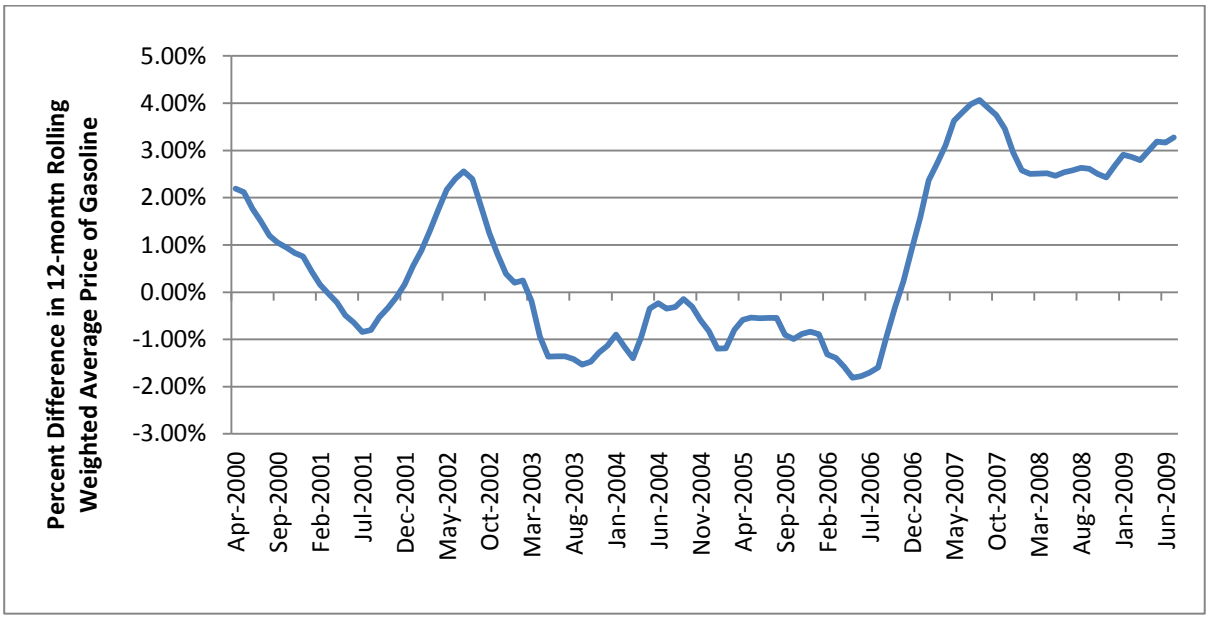
Gasoline Prices in Oregon and the statutory PADD-5: For almost a decade, Oregon's gasoline prices have varied within a very narrow range of the statutory PADD-5 prices. On page 104, Figure 11 graphs the 12-month rolling weighted average retail price of gasoline in Oregon and in the statutory PADD-5. 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



Data from Energy Information Administration websites:
Price: 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_DCU_SOR_M.htm

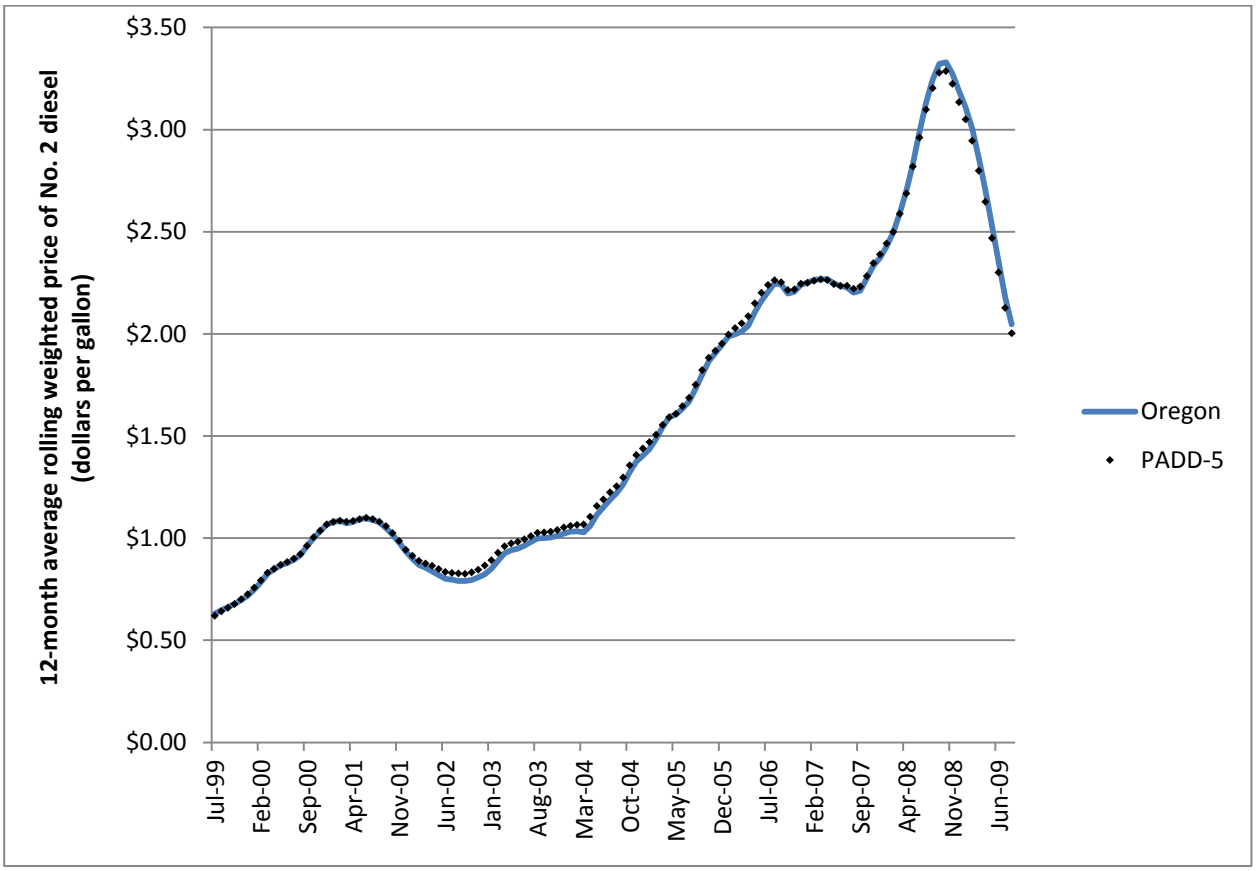
Figure 12: Percent Difference: Statutory PADD-5 and Oregon 12-month Rolling Weighted Average Retail Price of Gasoline: April 2000 to July 2009



Data from Energy Information Administration websites:
Price: 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_DCU_SOR_M.htm

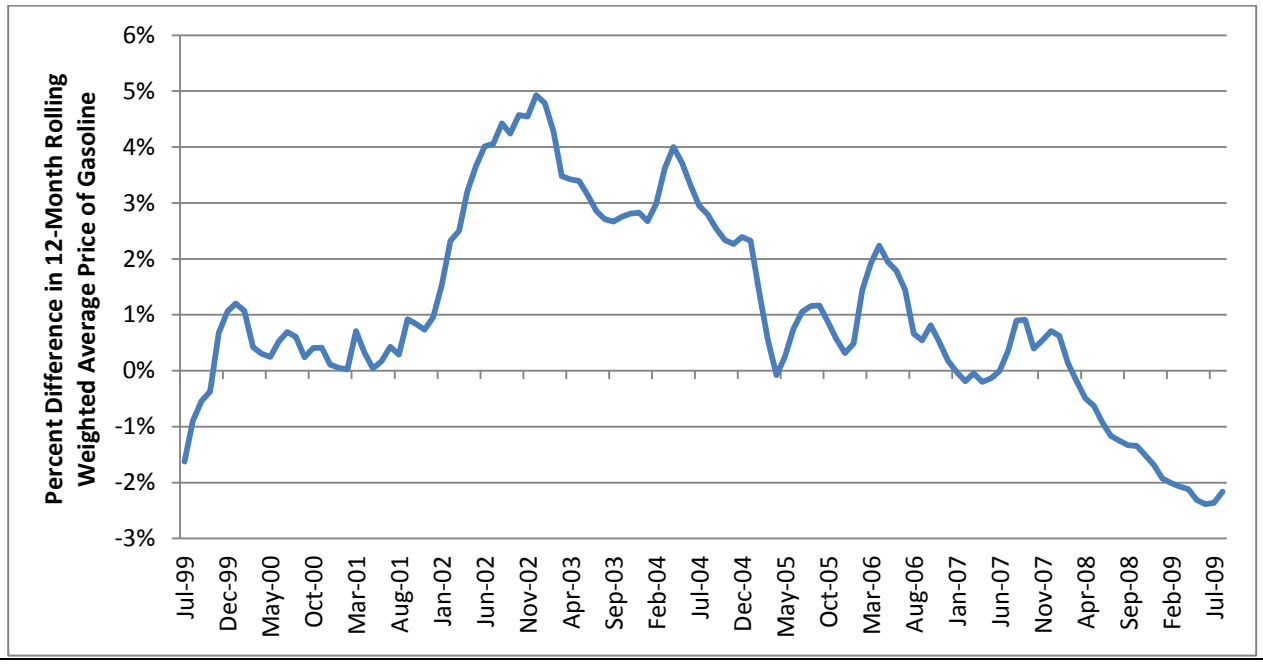
DEQ has looked at the variation in Oregon's price of diesel, compared to the actual PADD-5. Figure 13 on page 106 plots Oregon and PADD-5's diesel prices. Figure 14 on page 107 shows the percent difference between Oregon's and PADD-5 diesel prices for the past 10 years. In Figure 14 on page 107, positive 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.

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.

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"[7]) 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 (100C°). (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° 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

biogas?", [22]) 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

Program Element	Reviewed Annually	Reviewed 2014	Reviewed 2016
1. Fuel quality, and reliability issues and recommendations for addressing such issues	X (As needed)	X	X
2. Identification of implementation and compliance issues and recommendations for addressing such issues	X (As needed)	X	X
3. Fuel Price and Consumer Cost Safety Net review	X (As needed)	X	X
4. The need for rule deferrals and exemptions	X (As needed)	X	X
5. The low carbon fuel standards program's progress against targets (compliance)	X	X	X
6. The availability and use of low carbon fuels to achieve the low carbon fuel standards;	X	X	X
7. The rates of commercialization of fuels and vehicles	X	X	X
8. Advances in fuel-lifecycle analysis (GREET modeling,		X	X

Program Element	Reviewed Annually	Reviewed 2014	Reviewed 2016
indirect land use change modeling, other indirect effects quantification)			
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.		X	X
10. Energy economy ratios, particularly energy economy ratios for all heavy-duty applications and light-duty CNG.		X	X
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		X	X
12. Requirements for measuring electric vehicle use and review of which electrification activities qualify for credits.			X
13. Adjustments to the compliance schedule, if adjustments are needed beyond the existing exemptions and deferrals already available in Oregon's rule			X
13. Inclusion of fuel used in locomotive engines in the low carbon fuel standards program beginning in 2017			X
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			X

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).

House Bill 2186

Section 6(2)(b)(B): "The commission may adopt…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…and

(G) Adjustments to the amounts of greenhouse gas emissions per unit fuel energy assigned to fuels for combustion and drive train efficiency."

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

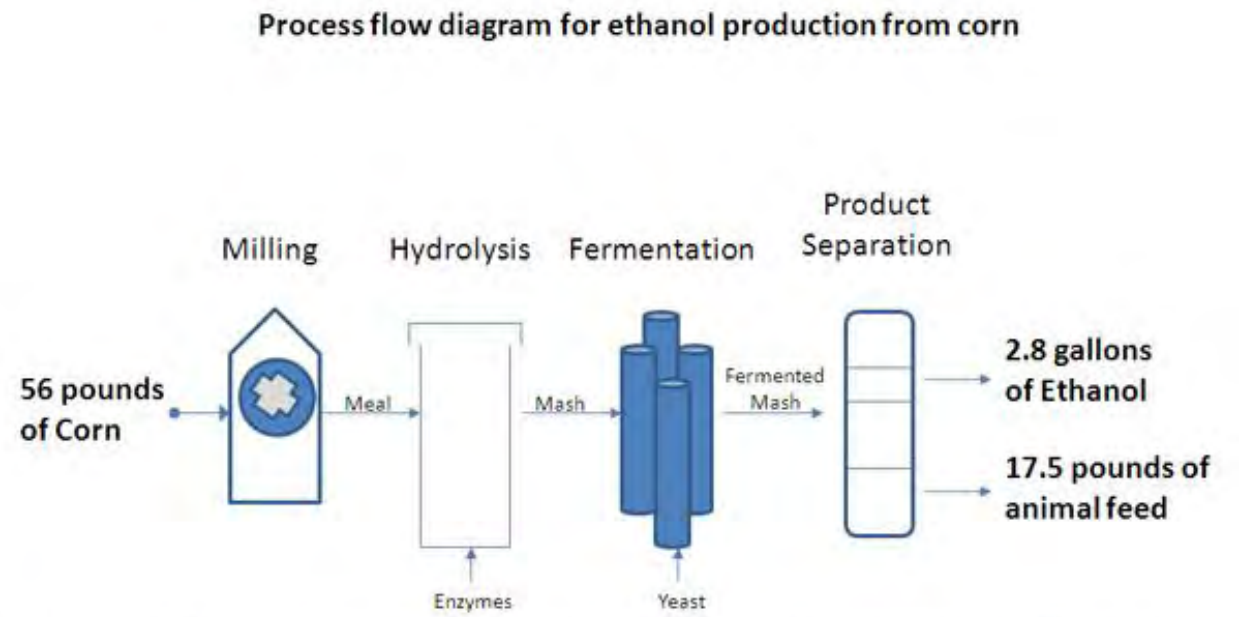
A. Overview

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.

Figure 15: Process Flow Diagram for Ethanol Production from Corn



Adapted From: *Analysis and Identification of gaps in research for the production of second-generation liquid biofuels. Schwietzke, et al. IEA Bioenergy.*
http://www.ftconferences.com/userfiles/file/Berndes%20Goran%20Gaps_in_the_Research_of_2nd_Generation_Transportation_Biofuels.pdf

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

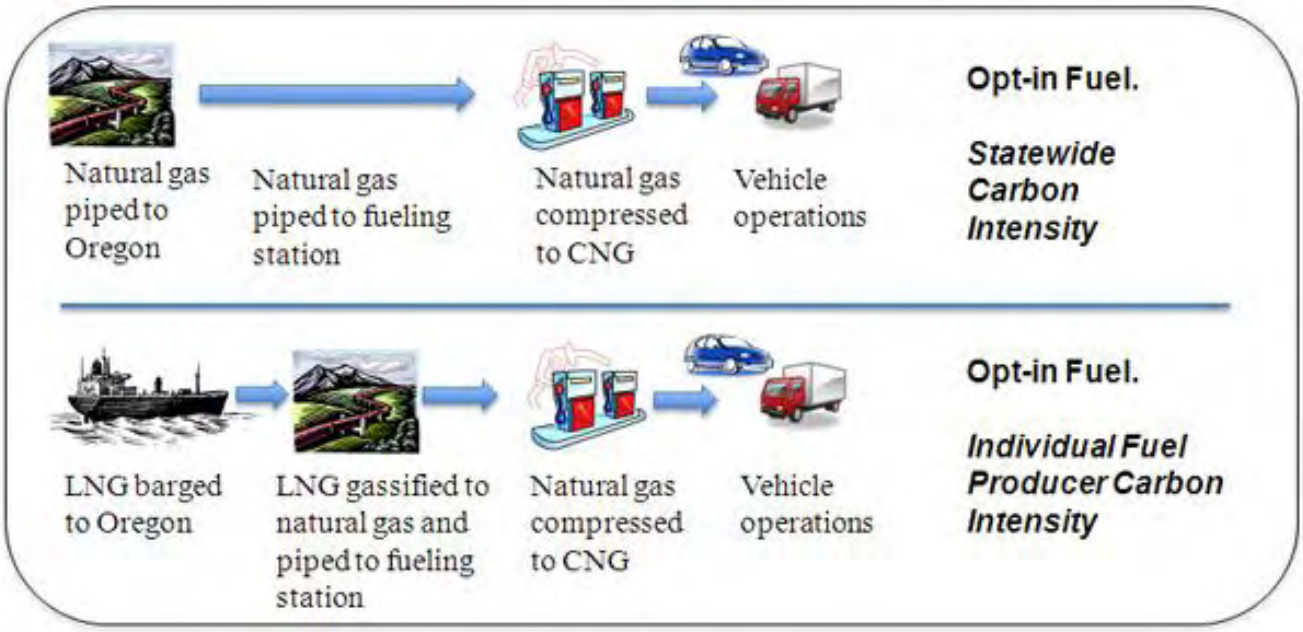
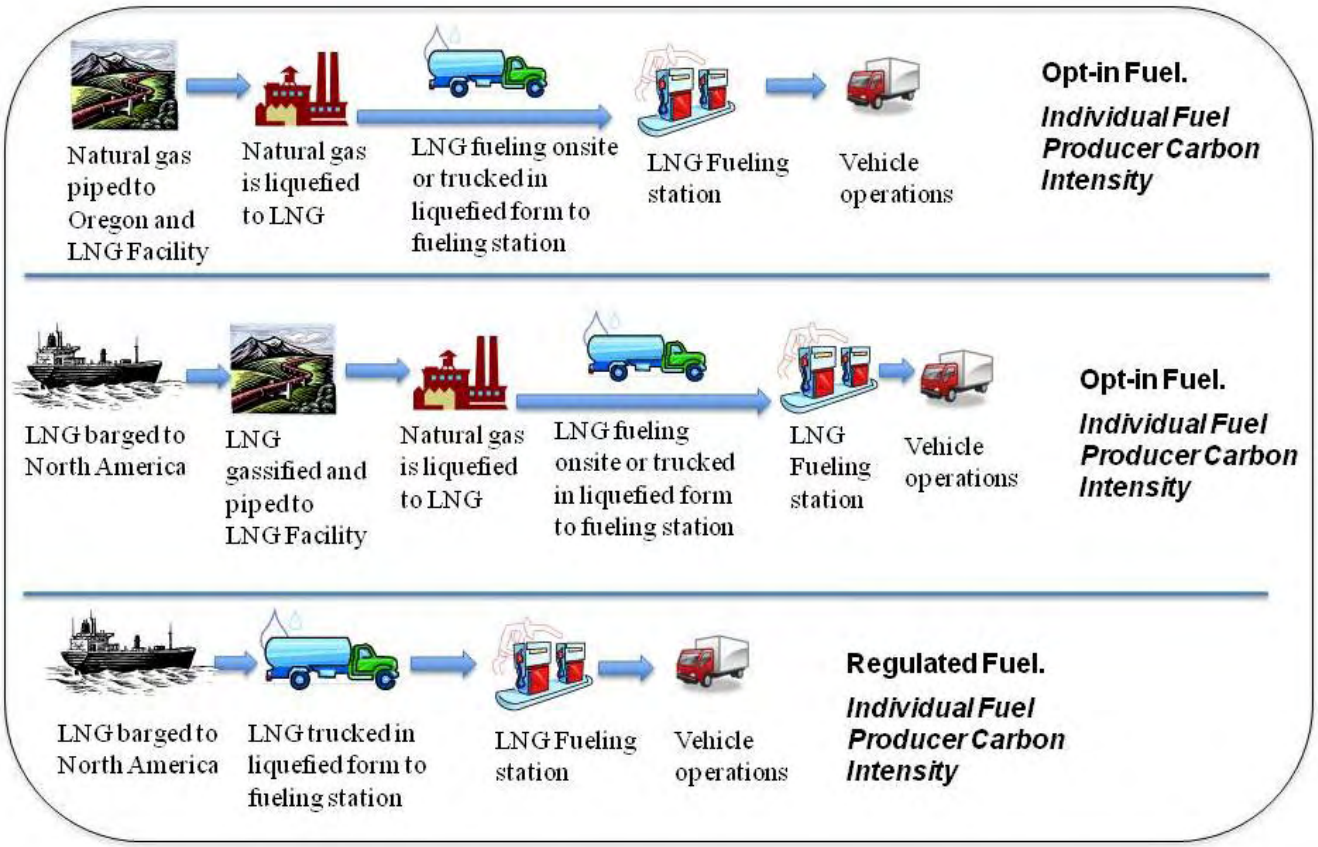


Figure 17: LNG Pathways, Carbon Intensity, and Opt-in/Regulated Parties



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.

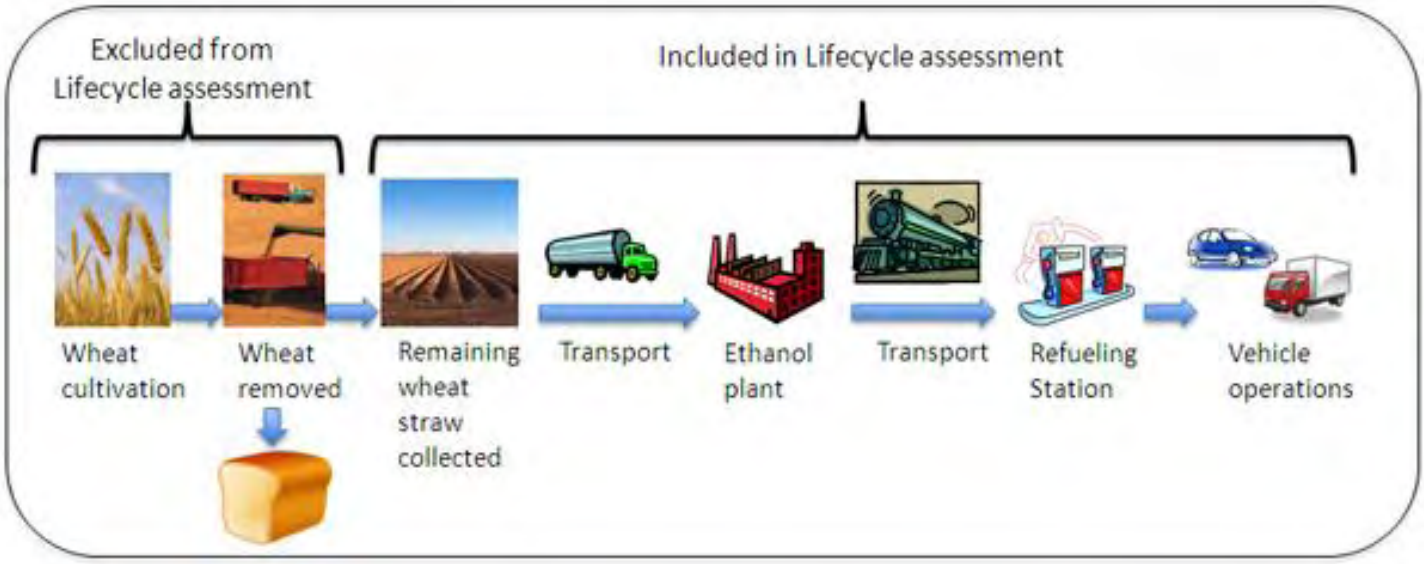
C. Lifecycle Analysis for Fuel Made from Waste

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).

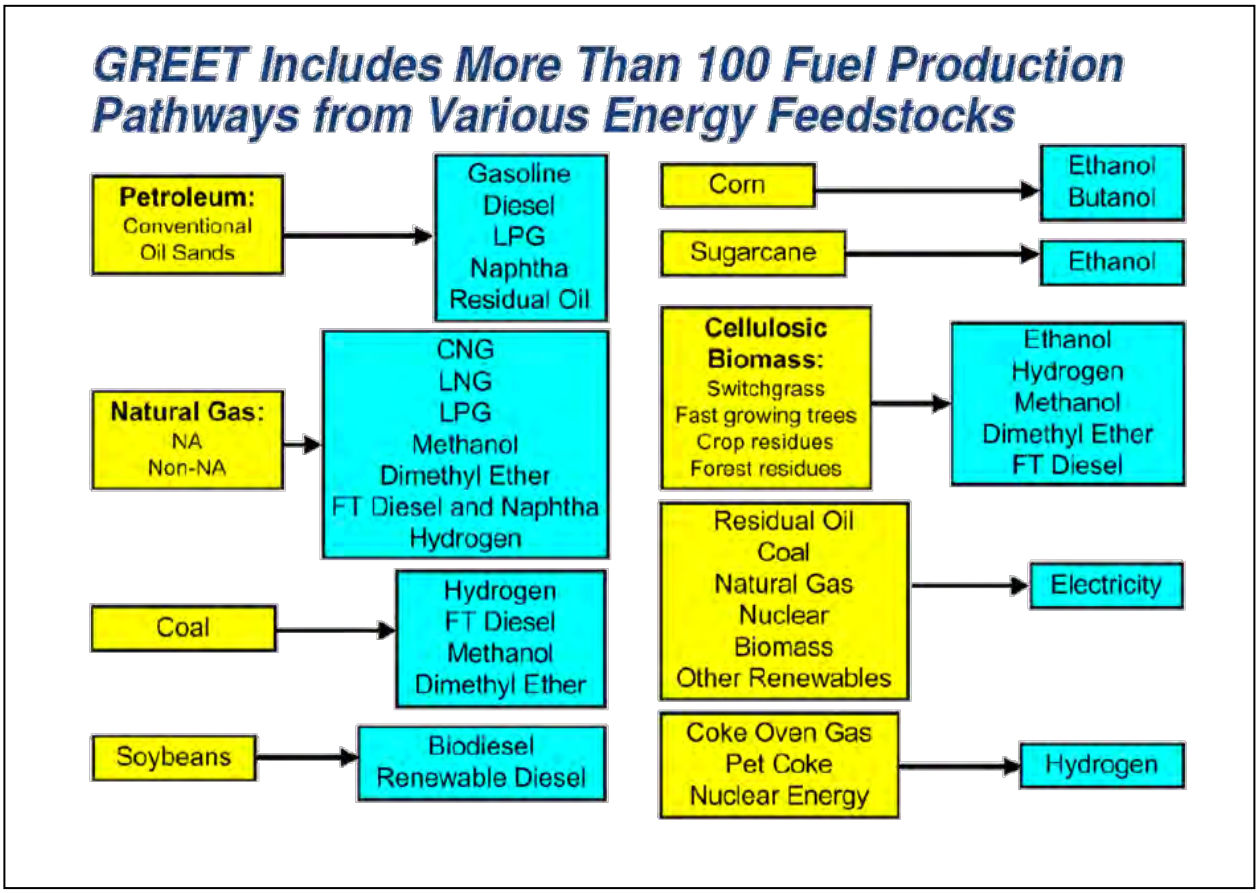
<u>Alternatives considered</u>

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.

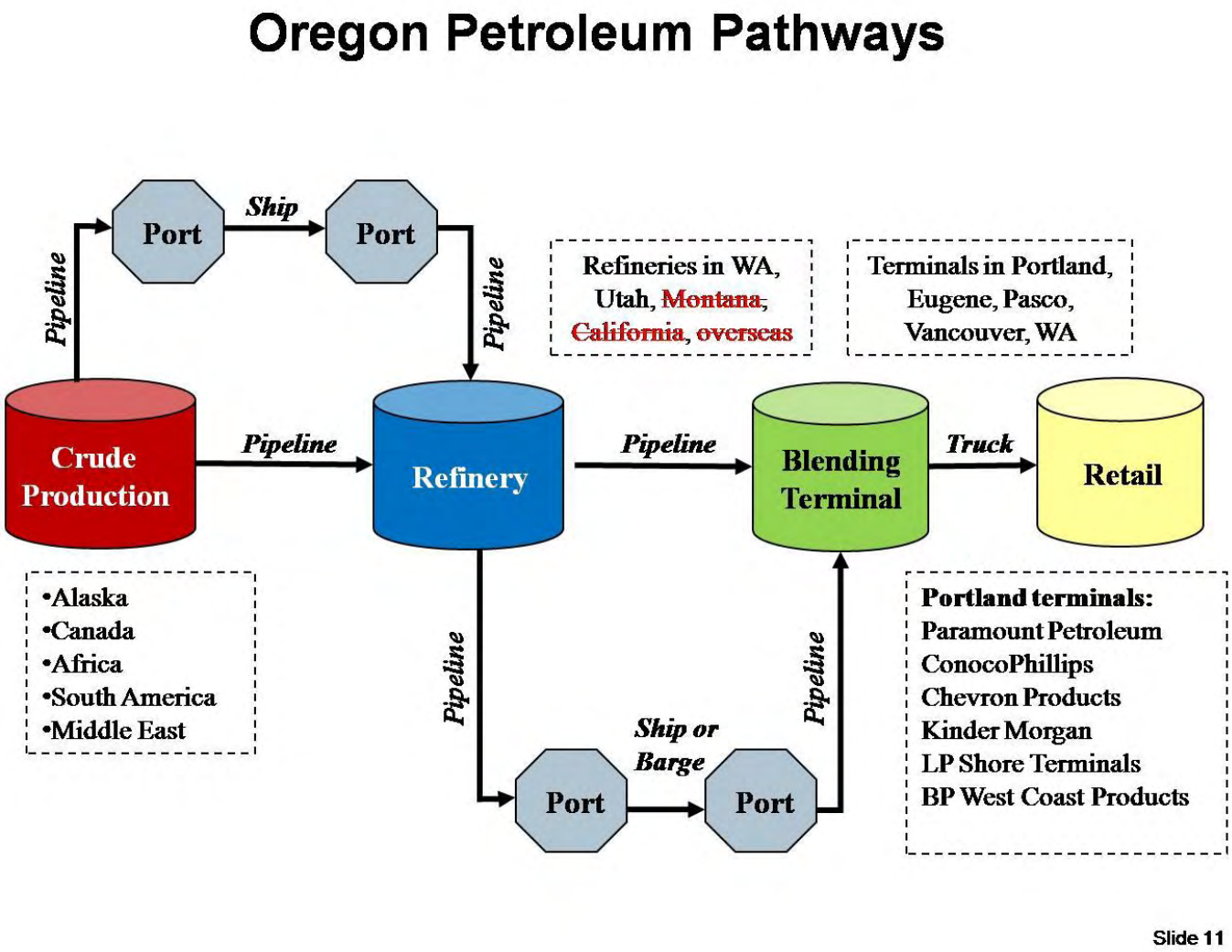
Figure 19: GREET Fuel Production Pathways



DEQ staff have customized GREET for Oregon (OR-GREET). For a description of inputs and assumptions, please see ***Appendix B: Lifecycle Analysis***.

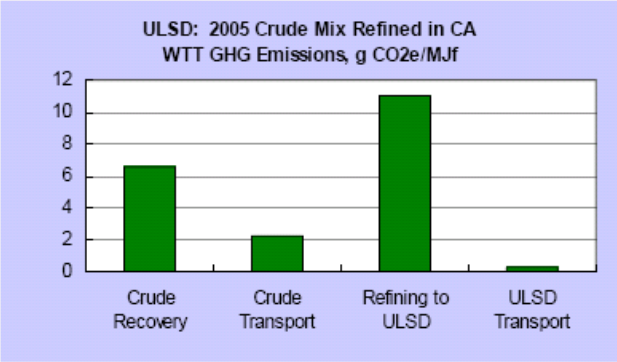
GREET calculates the carbon intensity of a fuel based on user inputs. Following are examples of Oregon petroleum pathways and key inputs for the petroleum pathways. For details on pathways, key inputs and assumptions for Oregon's fuels, please see ***Appendix B: Lifecycle Analysis***.

Figure 20: Oregon Petroleum Pathways



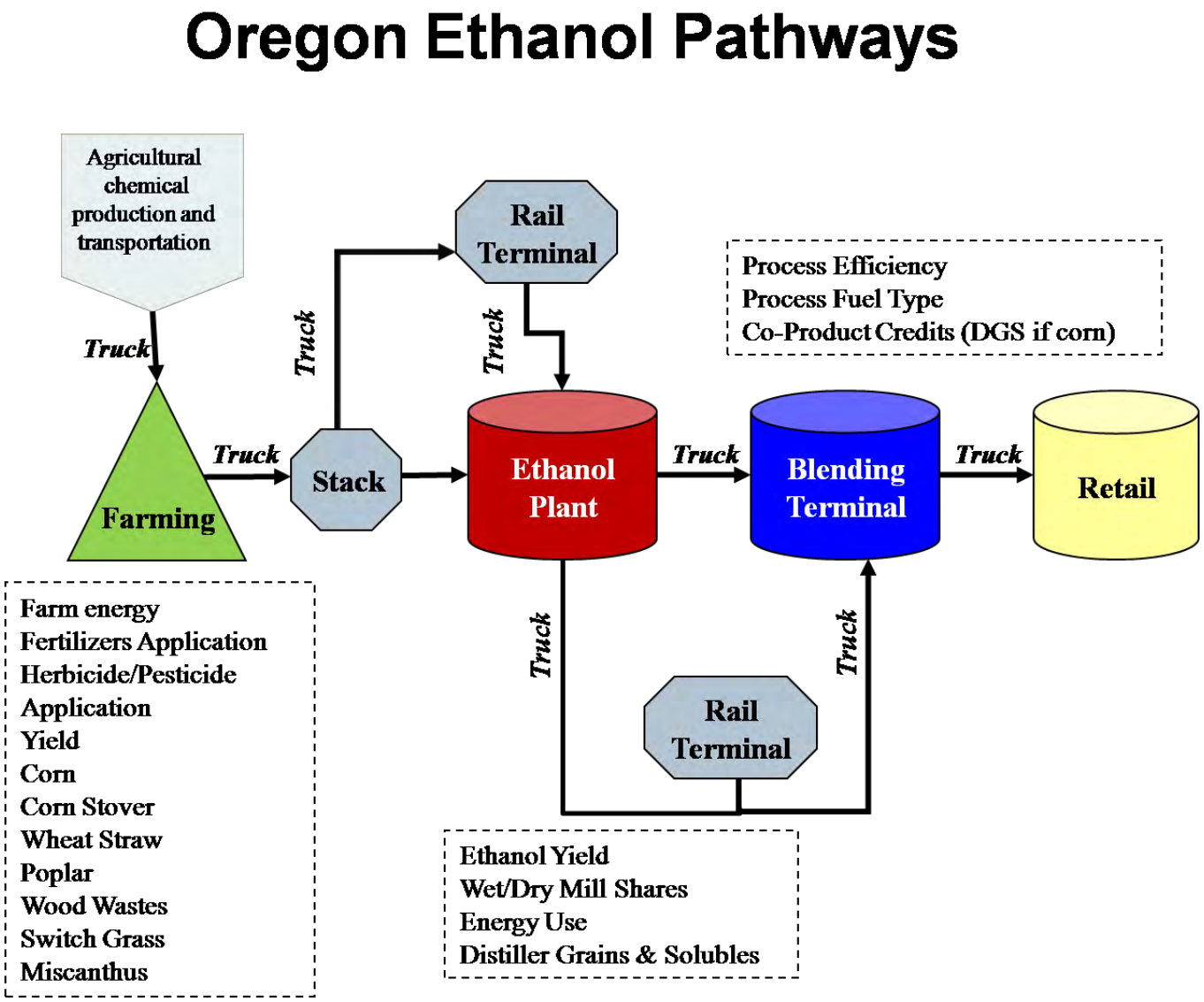
Petroleum Pathways – Key Inputs/Assumptions

- 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 (Btu/ton-mile)
    - Compressor station fuel mix
    - Prime mover mix at compressor stations
  - Losses



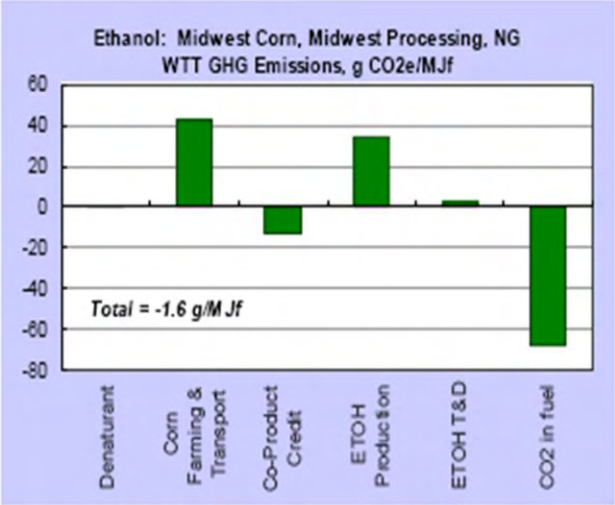
For an example of a biofuels pathway, we have included ethanol pathways and key inputs for the ethanol pathways.

Figure 21: Ethanol Pathways



Ethanol Pathways - Key Inputs/Assumptions

- Feedstock Assumptions
  - Material (corn, farmed trees, herbaceous, corn stover, forest residue)
  - Farming/collection energy use
    - Split by fuel type
    - Split by combustion device
  - Fertilizer/pesticide/herbicide
    - Amounts by type
    - Production energy consumption
    - Transport modes and distances
    - % of N in fertilizer emitted as N2O
  - Crop yields
  - Feedstock transport modes and distances
- Ethanol Production
  - Process efficiency (energy use)
    - Split by fuel type
    - Split by combustion device
  - Process yield (gal/bu)
  - Co-product credits (DGS substituted for feed corn & soybean meal)
  - Transport modes and distance



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***.

<u>Alternatives considered</u>

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.

House Bill 2186

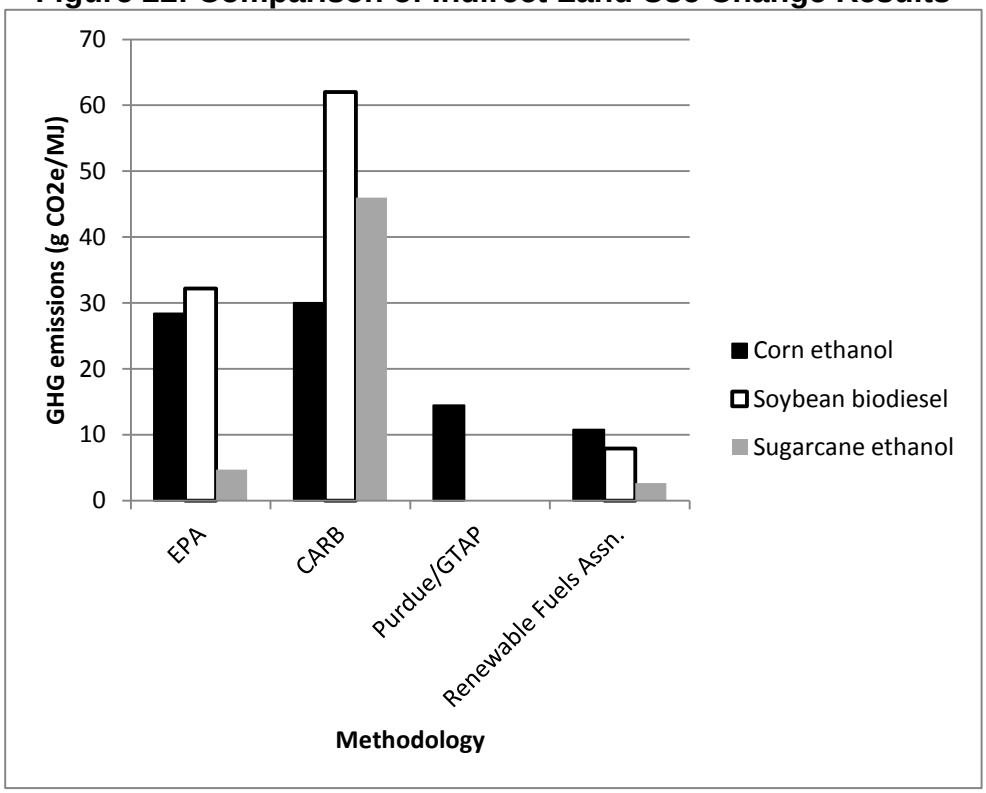
SECTION 6(2)(b)(B): "The commission may adopt…standards for greenhouse gas emissions attributable to the fuels throughout their lifecycles, including but not limited to emissions from the production, storage, transportation and combustion of the fuels and from changes in land use associated with the fuels."

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.

Figure 22: Comparison of Indirect Land Use Change Results



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 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

	Carbon Intensity			
Pathway	**Direct**	**Indirect Land Use Changes**		
	OR GREET g CO_2e/MJ	CARB g CO_2e/MJ	EPA g CO_2e/MJ	Purdue g CO_{2e}/MJ
Ethanol, MW Corn, MW Production	64.82	30.00	26.00	14.00
Ethanol, MW Corn, NW Production	56.99	30.00	26.00	14.00
Ethanol, Farmed Trees	15.54	5.00*	3.00	
Ethanol, Brazilian Sugarcane	26.44	46.00	5.00	**
Biodiesel, MW Soybeans	19.99	62.00	32.00	**
* 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).

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:
(2)(b)(G) Adjustments to the amounts of greenhouse gas emissions per unit of fuel energy assigned to fuels for combustion and drive train efficiency.

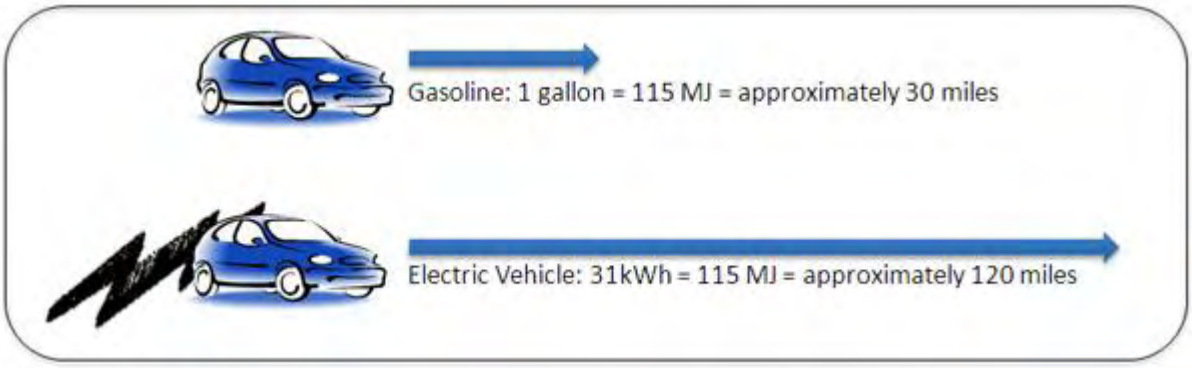
EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel (gasoline or diesel).

$$\text{EER} = \frac{\text{\# of miles driven/unit of energy consumed}}{\text{\# of miles driven per unit of energy for reference fuel}}$$

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.

Figure 23: Vehicle Distance Traveled



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

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

	Fuel/Vehicle Combination Energy Economy Ratio			
Year	**Gasoline or any ethanol blend**	**CNG / Internal combustion engine vehicle**	**Hydrogen or fuel cell vehicle**	**Electricity / battery electric vehicle, or plug-in hybrid electric vehicle**
2012	1.0	1.0 (needs to be adjusted: not reformulated gasoline)	3.0 (needs to be adjusted: not reformulated gasoline)	**4.1**
2013	1.0	1.0	3.0	4.0
2014	1.0	1.0	2.9	3.9
2015	1.0	TBA*	2.8	3.8
2016	1.0	TBA	2.8	3.7
2017	1.0	TBA	2.7	3.6
2018	1.0	TBA	2.6	3.5
2019	1.0	TBA	2.5	3.4
2020	1.0	TBA	2.5	3.3
2021	1.0	TBA	2.4	3.2
2022	1.0	TBA	**2.3**	**3.1**

*** 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

Fuel/Vehicle Combination Energy Economy Ratio			
Diesel fuel Or Biomass-based diesel blends	**CNG or LNG**	**Hydrogen or fuel cell vehicle**	**Electricity / battery electric vehicle, or plug-in hybrid electric vehicle**
1.0	0.94	1.9	**2.7**

***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

Alternative Vehicle	Methodology for calculating Energy Economy Ratios
Battery Electric Vehicles	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.
Plug-in Hybrid Electric Vehicles	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.
Combination of Light Duty Battery Electric and Plug-in Hybrid Electric Vehicles	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.
Fuel Cell Vehicles	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.

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 chose 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.

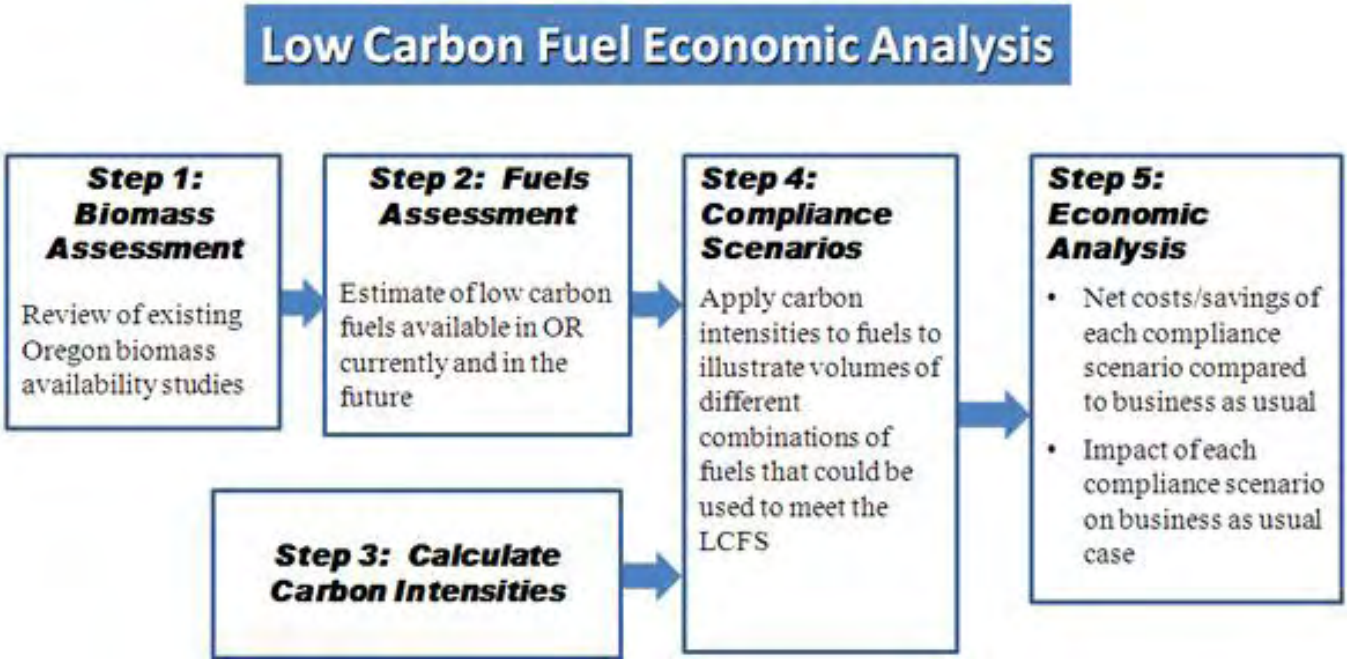
The basis of the compliance scenario approach is to identify which design factors are important enough to base decisions on and then bracket these parameters in an attempt to quantify the impact of each. This approach resulted in the advisory committee being able to compare eight different combinations 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.

Figure 24: Economic Analysis Process Flowchart



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 with standards 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***.

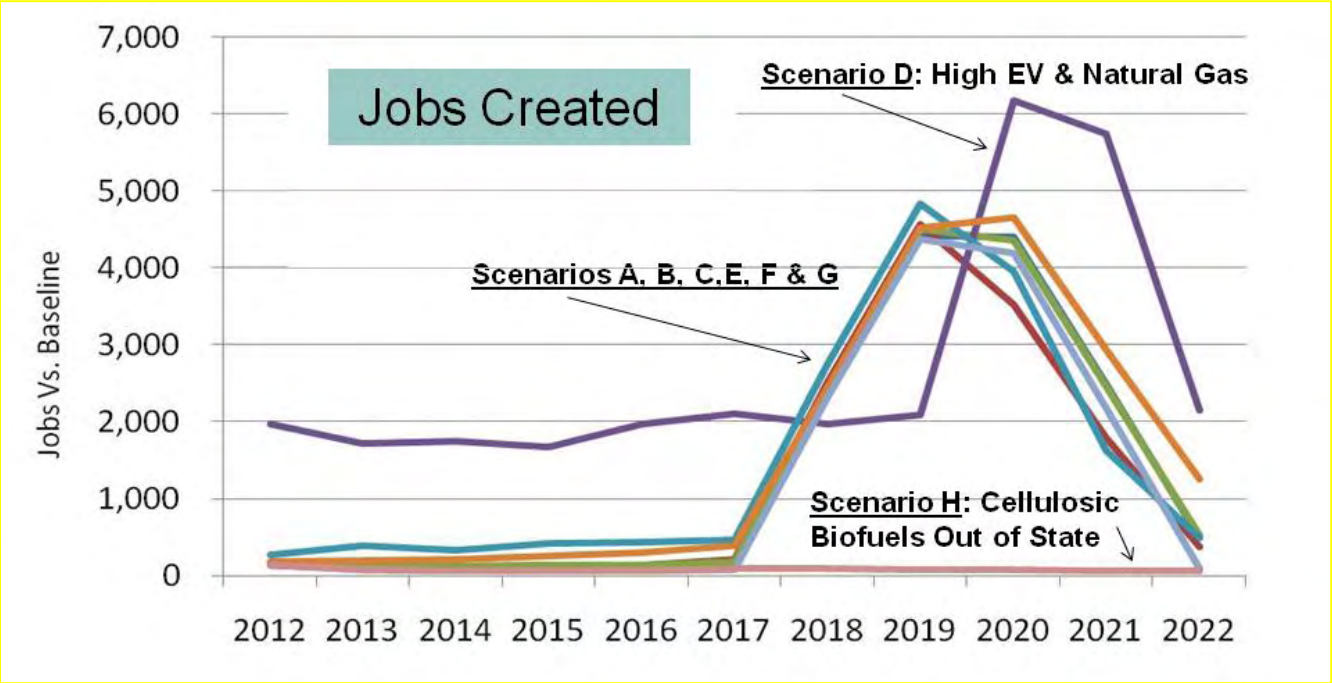
B. Economic Analysis Results

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.

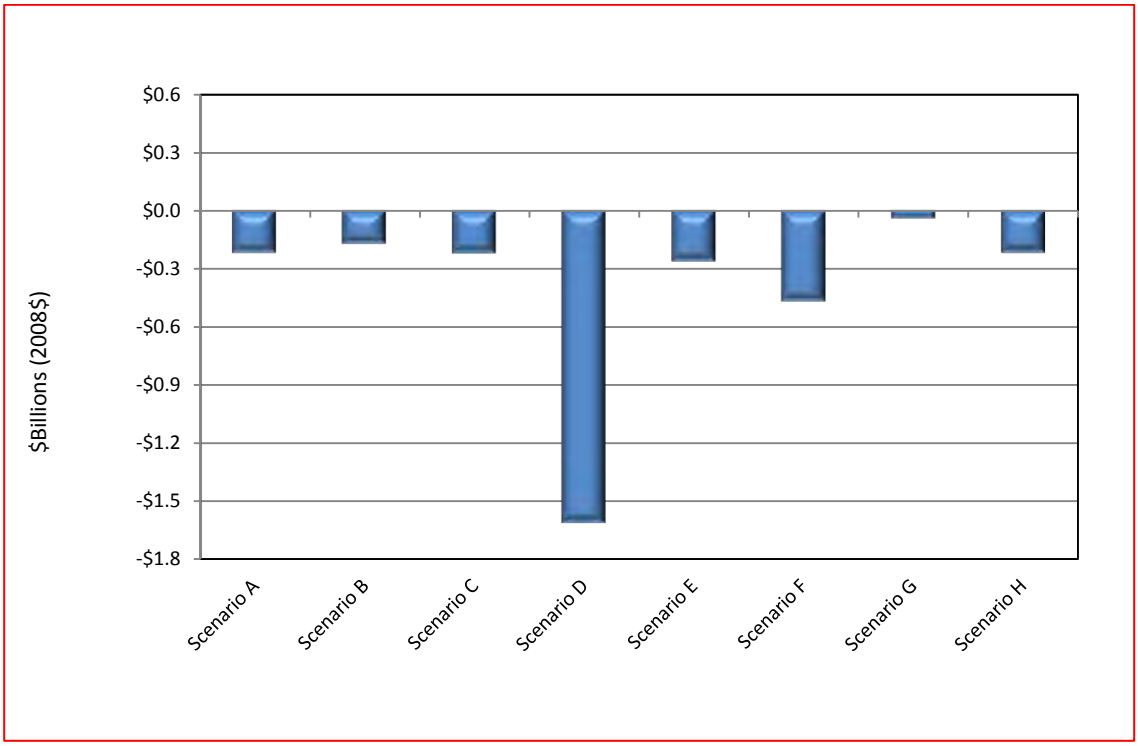
Figure 25: Impact on Oregon's Employment



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.

Figure 26: Household Fuel Spending vs. Business as Usual



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[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

[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.

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_3CHO) 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 $\mu g/m^3$ (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.

[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 particulat 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_2O) 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 $\mu g/m^3$ (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.

[ix] 3 $\mu g/m^3$ is the current Oregon Ambient Benchmark Concentration. EPA used a preliminary toxicity value of 0.08 $\mu g/m^3$ 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.

Fuel	PM	CO	SO2	NOx	VOC	Ozone
Ethanol Blends*	↓	↓	↓	↑	↓, ↑	

*(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.

Fuel	Acetaldehyde	Benzene	1,3-Butadiene	Formaldehyde	PAHs	Toluene	Xylene
Ethanol Blends	↑	↓	↓	↑	↓	↓	↓

4. Effect from Burning more Biodiesel

Biodiesel has become an increasingly attractive climate change strategy because it not only reduces direct CO_2 emissions from engines but also the diesel particulate matter which has a significant effect on climate change (600 - 900 times that of CO_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.

Fuel	PM	CO	NOx	VOC	Ozone	SO2	PAHs	Total Risk from Air Toxics
Biodiesel Blends**	-	-	-	↓	-	↓	↓	↓

**(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[x] 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.
- (d) "PADD 5 region" means the Petroleum Administration for Defense District 5 states of Arizona, Nevada, Oregon and Washington.

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:

---

[x] 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 14: Low Carbon Fuel Advisory Committee Member List

Name	Affiliation
Mark Reeve, Chair	Reeve Kearns, PC
Emily Ackland	Association of Oregon Counties
Carrie Atiyeh (alternate)	ZeaChem
Jonathan Burke	Westport Innovations Inc.
Todd Campbell (alternate)	Clean Energy
Eric Chung	PacifiCorp
Kyle L. Davis (resigned)	PacifiCorp
Marie Dodds	AAA
Brian Doherty (alternate)	Miller Nash/WSPA
Katie Fast (alternate)	Farm Bureau
Abe Fouhy	American Hydrogen Association Northwest
Jana Gastellum (alternate)	Oregon Environmental Council
Robert Grott	Northwest Environmental Business Council
Sam Hartsfield	Port of Portland
Marion Haynes	Oregon Business Association
Ian Hill	SeQuential Biofuels
Frank Holmes	Western States Petroleum Association
Brock Howell	Environment Oregon
Randy James	Portland and Western Railroad
Michael A. Johns	Lane County Department of Public Works
Christine Kelly	Oregon State Univ: Chemical, Biological & Env. Engineering
Mark Kendall	Oregon Environmental Council
Dan Kirschner	Northwest Gas Association
Tom Koehler	Pacific Ethanol
Allison Koenker (alternate)	Associated General Contractors
Geoff McPherson (resigned)	Citizen
Matt Michel	Canby Utility
David N. Patterson	Mitsubishi Motors R&D of America
Harrison Pettit	ZeaChem Inc.
Andrew Plambeck	Ecumenical Ministries of Oregon
Sam Pounds	Tidewater Barge Lines
Joshua Proudfoot	Good Company
Marcy Putman	Labor Union – IBEW
John Rakowitz	Associated General Contractors
Danelle Romain	Oregon Petroleum Association
Paul Romain	Oregon Petroleum Association
Bob Russell	Oregon Trucking Association
Jennifer Shmikler	Farm Bureau

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 is 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.

LIST OF REFERENCES

[1] "Motor Fuel & Distillate In Oregon Quantity, Sources & Distribution", presentation to the Low Carbon Fuel Standards Advisory Committee. November 3, 2009. Rick Wallace, Oregon Department of Energy. Oregon DEQ website, http://www.deq.state.or.us/aq/committees/docs/lcfs/wallacePresent.pdf.

[2] "Motor Fuel & Distillate In Oregon Quantity, Sources & Distribution", presentation to the Low Carbon Fuel Standards Advisory Committee. November 3, 2009. Rick Wallace, Oregon Department of Energy. Oregon DEQ website, http://www.deq.state.or.us/aq/committees/docs/lcfs/wallacePresent.pdf.

[3] "Alternatives to Traditional Transportation Fuels. Estimated Number of Compressed Natural Gas (CNG) Vehicles in Use by User Group and State." U.S. Dept. of Energy, Energy Information Administration. Accessed October 28, 2010, http://www.eia.doe.gov/cneaf/alternate/page/atftables/attf_v9.html.

[4] "Biofuel Renewable Fuel Standard." Oregon Dept. of Agriculture. Accessed October 28, 2010, http://oregon.gov/ODA/MSD/renewable_fuel_standard.shtml.

[5] "Total Crude Oil Exports by Destination, 2009 Annual Report." Canada National Energy Board. Accessed May 4, 2010. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/ttlcrdlxprtdstntn-eng.html.

[6] "E85 Fuel Dispensers." U.S. EPA. Accessed October 26, 2010, http://www.epa.gov/smartway/growandgo/e85dispensers.htm.

[7] "E85 Safety Concerns." U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed October 17, 2010, http://www.afdc.energy.gov/afdc/ethanol/safety.html.

[8] "Ethanol-Gasoline Fuel Blends May Cause Human Health Risks and Engine Issues." Olga V. Naidenko, PhD, Senior Scientist. Environmental Working Group. Accessed October 26, 2010, http://www.ewg.org/files/2009/ethanol-gasoline-white-paper.pdf.

[9] "Fuels: Biodiesel." Columbia-Willamette Clean Cities. Accessed October 25, 2010, http://www.cwcleancities.org/fuels_biodiesel.php.

[10] "Biodiesel Handling and Use Guide." U.S. Dept. of Energy, National Renewable Energy Laboratory. Accessed October 25, 2010, http://www.nrel.gov/vehiclesandfuels/npbf/pdfs/43672.pdf.

[11] "Fuels: Biodiesel." Columbia-Willamette Clean Cities. Accessed October 25, 2010, http://www.cwcleancities.org/fuels_biodiesel.php.

[12] "What is hydrogenation-derived renewable diesel?" U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed October 25, 2010, http://www.afdc.energy.gov/afdc/fuels/emerging_green_what_is.html.

[13] "Hydrogenation-Derived Renewable Diesel Distribution." U.S. Dept. of Energy, Alternative Fuels and AdvancedVehicles Data Center. Accessed April 5, 2010, http://www.afdc.energy.gov/afdc/fuels/emerging_green_distribution.html.

[14] "Electricity." U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed April 5, 2010, http://www.afdc.energy.gov/afdc/fuels/electricity.html.

[15] "Maintenance and Safety of Hybrid, Plug-in Hybrid, and All-Electric Vehicles." U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed April 5, 2010, http://www.afdc.energy.gov/afdc/vehicles/electric_maintenance.html.

[16] "How safe are Natural Gas Vehicles?" Technology Committee Bulletin, Clean Vehicle Education foundation. Accessed October 28, 2010, http://www.cleanvehicle.org/committee/technical/PDFs/Web-TC-TechBul2-Safety.pdf.

[17] "How safe are Natural Gas Vehicles?" Technology Committee Bulletin, Clean Vehicle Education foundation. Accessed October 28, 2010, http://www.cleanvehicle.org/committee/technical/PDFs/Web-TC-TechBul2-Safety.pdf.

[18] "How safe are Natural Gas Vehicles?" Technology Committee Bulletin, Clean Vehicle Education foundation. Accessed October 28, 2010, http://www.cleanvehicle.org/committee/technical/PDFs/Web-TC-TechBul2-Safety.pdf.

[19] "How safe are Natural Gas Vehicles?" Technology Committee Bulletin, Clean Vehicle Education foundation. Accessed October 28, 2010, http://www.cleanvehicle.org/committee/technical/PDFs/Web-TC-TechBul2-Safety.pdf.

[20] "CNG and LNG: Alternative Fuels." U.S. Department of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed April 5, 2010, http://www.afdc.energy.gov/afdc/fuels/natural_gas_cng_lng.html.

[21] "Fuels: More Alternative Fuels." Columbia-Willamette Clean Cities. Accessed April 5, 2010, http://www.cwcleancities.org/fuels_alt_fuels.php.

[22] "What is biogas?" U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed April 5, 2010, http://www.afdc.energy.gov/afdc/fuels/emerging_biogas_what_is.html.

[23] "What is a fuel cell vehicle?" U.S. Dept. of Energy, Alternative Fuels and Advanced Vehicles Data Center. Accessed October 10, 2010, http://www.afdc.energy.gov/afdc/fuels/emerging_biogas_what_is.html.http://www.afdc.energy.gov/afdc/vehicles/fuel_cell_what_is.html.

[24] "Fuel Cell Vehicles." U.S. Dept. of Energy, Alternative Fuels and Advances Vehicles Data Center. Accessed October 10, 2010, http://www.afdc.energy.gov/afdc/vehicles/fuel_cell.html.

[25] "Fuels: Hydrogen." Columbia-Willamette Clean Cities. Accessed April 5, 2010, http://www.cwcleancities.org/fuels_hydrogen.php.

[26] "Hydrogen Compared with Other Fuels." H2 BestPractices. Accessed April 5, 2010, http://www.h2bestpractices.org/h2properties/.

[27] California Environmental Protection Agency Air Resources Board. March 4, 2009. *Proposed Regulation to Implement the Low Carbon Fuel Standard*, Vol. 2. Appendix C1: C-5,C-6

[28] California Environmental Protection Agency Air Resources Board. March 4, 2009. *Proposed Regulation to Implement the Low Carbon Fuel Standard*, Vol. 2. Appendix C1: C-5,C-6

[29] California Environmental Protection Agency Air Resources Board. March 4, 2009. *Proposed Regulation to Implement the Low Carbon Fuel Standard*, Vol. 2. Appendix C1: C-5,C-6

[30] "Review of Fuel Ethanol Impacts on Local Air Quality." Bio-Ethanol for Sustainable Transport. BEST Deliverable No D9.14 May 2008. London. Accessed November 10, 2010, http://www.best-europe.org/upload/BEST_documents/info_documents/Best%20reports%20etc/D9.14%20-%20Review%20of%20Ethanol%20Fuel%20Impacts%20on%20Local%20Air%20Quality_080516.pdf.

[31] "Impact of Biodiesel Fuels on Air Quality and Human Health." U.S. Dept. of Energy National Renewable Energy Laboratory. Morris, et. al. ENVIRON International Corp. May 2003. Accessed November 9, 2010, http://www.afdc.energy.gov/afdc/pdfs/33793.pdf.

Economic Impact Analysis of the Low-Carbon Fuel Standard Rule for the State of Oregon

Prepared for:
Oregon Department of Environmental Quality

Prepared by:
Jack Faucett Associates, Inc.

Economics
Public Policy
Planning
Jack Faucett Associates
Since 1963

January 2011

11-AQ-004d
1/25/2011

Page Intentionally Left Blank to Facilitate Duplex Printing

Acknowledgements

This report was prepared by Jack Faucett Associates (JFA). The Oregon DEQ and TIAX, LLC developed the Low Carbon Fuel Standard compliance scenarios with substantial input from the Oregon Low Carbon Fuel Advisory Committee. TIAX, LLC 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 including David Collier, Cory-Ann Wind, Sue Langston and Svetlana Lazarev. The TIAX, LLC staff included Jennifer Pont and Jeff Rosenfeld. REMI Northwest model runs were conducted by Alec Miller. Michael F. Lawrence and Scott Williamson conducted the study for JFA and are responsible for this report.

The contents of this report reflect the view of the authors who are solely responsible for the facts and accuracy of the material presented. The contents do not necessarily reflect the official views of the Oregon Department of Environmental Quality.

Table of Contents

Introduction 5
National Movement to Low Carbon Fuel Standards 5
Oregon Low-Carbon Fuel Standard 8
Methodology 14
Measuring Economic Impacts 14
Scenario Development 17
Scenario Selection 19
VISION Modeling 23
Assumptions 24
Results 25
VISION to REMI 25
Assumptions and Results 26
MACRO Modeling 27
Assumptions 27
PI+ Results 27
Special Scenario Pairings 38
Conclusion 44
Appendix A: VISION Results 46
Appendix B: REMI PI+ Results 67

Introduction

National Movement to Low Carbon Fuel Standards

Strategies to reduce greenhouse gas emissions from the transportation sector generally fall into three distinct approaches. The first approach relies on VMT reduction strategies, which seek to reduce overall vehicle travel. The second approach places an emphasis on vehicle-technology strategies, which seek to make vehicles more efficient in their ability to transport people and goods. The third approach contains fuel strategies, which seek to change the content of vehicle fuels so that emissions are reduced. Low carbon fuel standards fall within the fuels-strategies approach.

Low carbon fuel standard policies (often referred to as "LCFS" policies) make up a distinct approach to responding to public concern about the emissions of greenhouse gases that cause climate change. While not all low carbon fuel standard policies are equal, they are generally characterized by a focus on the intensity of emissions from fuel consumed, rather than on the exact type of fuel consumed. This approach, which specifically does not mandate a particular fuel or fuel mix for any part of the vehicle fleet, is often referred to as a performance-based standard. Without specifying a required fuel source, an LCFS seeks to lower the intensity of emissions from transportation fuels. Unlike mandates to displace gasoline with ethanol or electricity, or to displace diesel with biodiesel, an LCFS strategy simply establishes an overall emissions standard for the fuel mix.

This approach seeks to create flexibility, and to allow those impacted by the regulation to find their own way to the most cost-effective path to compliance. There are many different fuels available to the transportation sector, from natural gas to electricity to a wide variety of biofuels feed stocks, each with its own cost and each with its own greenhouse gas reduction capacity. This variety produces many different options for achievement of a lower-carbon fuel mix.

Because of the flexibility such an approach offers to regulated industries, low carbon fuel standards have attracted interest around the country. California was the first to enact an LCFS, and analyses of similar policies are taking place in Washington, Oregon and the northeast region. Information from analyses of related policies, such as biofuels or electric-vehicle policies, is available to improve states' understanding of what outcome an LCFS might produce, and what costs such a policy might impose.

Federal RFS and RFS2 Targets

There has never been (and there is not now) a federal low-carbon fuel standard. The government has enacted two different Renewable Fuel Standards (referred to by the acronym "RFS"), however. The original RFS, passed as part of the Energy Policy Act of 2005, mandated that 7.5 billion gallons of renewable fuel be blended into the gasoline supply by the year 2012. The second RFS (referred to as "RFS2") was included in the Energy Independence and Security Act of 2007 (EISA 2007), a statute which famously also mandated increases in vehicle fuel efficiency. RFS2 superseded the original policy, and mandated that 36 billion gallons of renewable fuels be blended into the transportation fuel mix by 2022. Within this 36-billion-gallon requirement were specific sub-requirements for different types of renewable fuels.[1]

The RFS approach is distinct from an LCFS approach in that it mandates that specific fuels be consumed, rather than setting a broad target and allowing regulated parties to select their own approach to compliance.

California Low-Carbon Fuel Standard

In 2007, Governor Schwarzenegger established a low-carbon fuel standard for the state of California by executive order. This LCFS, which sets a target of 10% reduction in the carbon intensity of fuels by the year 2020, was further developed by California's Air Resources Board to contain intermediate targets for each year between 2011 and 2020.

California has not only a 10% reduction target after ten years, but also specific intermediate targets for each year:

Year	Percent Reduction in Carbon Intensity
2010 (Baseline)	0%
2011	0.25%
2012	0.5%
2013	1%
2014	1.5%
2015	2.5%
2016	3.5%

[1] "Renewable Fuel Standards (RFS)". Environmental Protection Agency Office of Transportation and Air Quality. Retrieved from http://www.epa.gov/otaq/fuels/renewablefuels/index.htm.

2017	5%
2018	6.5%
2019	8%
2020	10%

Oregon's proposed LCFS has intermediate requirements by which the fuel supply must meet progressively stricter standards over the ten-year span from 2012 through 2022. 2012 serves as the baseline (in which no improvement is mandated). Improvements are mandated starting in 2013, and as in California, the final target is to be reached in the tenth year of the ramp-up in 2022.

Also, California's LCFS is distinguished in terms of flexibility of compliance by the opportunity for regulated parties to comply by purchasing emissions credits from clean-electricity providers. Because the state has already authorized the trading of emissions credits, transportation fuel providers may utilize that approach toward achieving the mandated LCFS targets. Oregon will also allow for the purchase and trading of low carbon fuel credits as a method of LCFS target compliance.

Washington Low-Carbon Fuel Standard

In May 2009, Governor Christine Gregoire issued Executive Order (E.O.) 09-05, Washington's Leadership on Climate Change. E.O. 09-05 directs the Washington Department of Ecology (Ecology) to assess whether the California Low Carbon Fuel Standard (LCFS) or a modification thereof would best meet Washington's greenhouse gas emissions reduction targets.

Accordingly, in consultation with Washington Departments of Commerce and Transportation, and with consultant assistance, Ecology will:

- Assess various lower carbon fuel programs and options.
- Assess how those options would align with Washington's transportation fuel supplies, greenhouse gas reduction targets, and state economic conditions,
- Recommend whether or not to pursue adoption of a low carbon fuel standard for Washington, what LCFS policies would best fit Washington, and if not recommended what alternatives could help achieve state GHG targets.

Ecology has completed its compliance scenario development, emissions reduction benefits, economic impact analysis and evaluation of alternatives. Ecology is now evaluating the options.

Oregon Low-Carbon Fuel Standard

Options for Compliance

Low-Carbon Fuel Standards present regulated communities with multiple options for compliance. Many types of fuels offer reduced emissions when compared against gasoline and diesel. Response strategies may target the light-duty fleet, which is very large and uses mostly gasoline, or they may target the heavy-duty fleet, which generates significant emissions from a smaller, mostly diesel-powered fleet.

Biofuels

The combustion of biofuels, a category which includes ethanol and biodiesel, generally emits less greenhouse gases per unit of energy than combustion of gasoline and diesel, when analyzed on a life cycle basis. Displacing conventional gas and diesel with biofuels, therefore, reduces the overall carbon intensity of the fuel mix and thus achieves progress toward LCFS targets. [2]

This can be done in many ways. Current federal regulations allow for the use of gasoline blended with up to 10% ethanol content in the on-road fleet of light-duty vehicles (a category including cars, SUVs and pickup trucks). In addition, recent federal regulatory changes allow for a blend of 15% ethanol in gasoline for vehicles of the 2007 or later model years, and may soon allow this fuel to be used in older vehicles as well. Oregon has not yet authorized gasoline blends containing more than 10% ethanol for use in the state. Encouraging the sale and consumption of these blended fuels, rather than of unblended gasoline, is one approach to reducing carbon intensity of fuels. More aggressive approaches to biofuels might seek to expand the use of flex-fuel vehicles, which can run on either gasoline or an ethanol-dominant blend (as high as 85% ethanol and 15% gasoline). Expanding the availability and consumption of biodiesel, or of hydrogenation-derived renewable diesel, in the heavy-duty fleet is an additional approach.

[2] The carbon intensities discussed here are estimated on a "Life cycle" basis. Life cycle carbon intensities measure not only the greenhouse gases contained in the fuel and emitted from the tailpipe upon combustion, but also the emissions required to grow, harvest, refine and transport the fuels to market. Cellulosic fuels gain an advantage over corn primarily in these "upstream" phases – they require less energy to grow and refine than corn typically does, or are made from waste products. Calculations of life cycle greenhouse gas emissions are generated by DEQ and it's contractor, TIAX llc, using a model developed by DOE and can be independently assessed through the GREET emissions measurement tool, available at http://greet.es.anl.gov/. Oregon and TIAX have customized this GREET model to reflect Oregon-specific conditions.

Biofuels come from many different types of crops. The type of crop, as well as the process used to refine the feedstock, determines the amount of carbon reduction. The production and consumption of corn ethanol, which is common in the US, is relatively carbon intensive and represents only a moderate savings compared to conventional gasoline. Ethanol and biodiesel from stocks such as waste wheat straw, forest residue, farmed trees, waste berries, sugarcane, switchgrass or other cellulosic sources are less carbon intense, and are thus far more helpful in meeting LCFS targets.

Electricity and Hybridization

By virtue of their comparative efficiency when compared against conventional fuels, electric vehicles are also beneficial to reaching an LCFS target. Electric vehicles and plug-in hybrid electric vehicles use an electric motor (either independently or in combination with a conventional engine) to achieve low-carbon transportation.

These are included in LCFS strategies despite the fact that electricity is not usually a low-carbon fuel. In fact, electricity from coal is actually significantly more carbon-intensive than gasoline or diesel, when measured per unit of energy. Outside of the northwest, the current national electricity supply is dominated by coal-fired and natural-gas fired generation, and is a carbon-intensive energy source. In Oregon, the future of electricity generation will become less carbon-intense due to a state renewable portfolio standard and the closure of its only coal-fired power plant. Electric vehicles remain in LCFS strategies, however, because vehicular efficiency (how far the vehicle can go on the same amount of energy) is projected to be so much greater for these vehicles than for conventional vehicles that it overwhelms the carbon intensity of electricity.

These projections of great efficiency in electric vehicles are corroborated by recent EPA ratings for emerging electric vehicle models. The Nissan Leaf received ratings of over 90 miles per gas-gallon equivalent (the amount of electricity equivalent to the energy in a gallon of gas). This level of energy efficiency is roughly triple that of the average new automobile, and roughly quadruple that of the gasoline-powered vehicle fleet currently on the road. The Chevrolet Volt, which can run on both an electric charge and on electricity generated by an on-board gasoline engine, received two distinct efficiency ratings. When running on electricity from a charged battery (i.e. running directly on electricity), it also receives a rating just above 90 miles per gas-gallon equivalent. It is not as efficient when relying on gasoline, however; it achieves only 37 miles per gallon when drawing power from its gasoline engine. The analysis involved in developing these scenarios assumed relative efficiencies of the electric and gasoline fleets similar to these numbers.

Internal combustion engines expend most of the energy contained in gasoline in the form of noise, heat and vibration, applying only a fraction of the fuel's energy content to actually turning the wheels. By avoiding energy losses associated with fuel combustion, vehicles running on electricity can direct a greater share of their stored energy toward motion.

Natural gas and biogas

The combustion of natural gas, either in compressed (CNG) or liquefied (LNG) form, generally emits less greenhouse gases per unit of energy than combustion of gasoline and diesel, when analyzed on a life cycle basis. Displacing conventional gas and diesel with natural gas, therefore, reduces the overall carbon intensity of the fuel mix and thus achieves progress toward LCFS targets. This is true despite the fact that liquefied natural gas contains less energy per gallon than diesel, and consequently permits fewer miles of travel per gallon.

Compressed and liquefied natural gas can be utilized in both the light-duty and heavy-duty fleets. For the purpose of this analysis, however, the scenarios involving expanded use of natural gas fuels directed all new natural gas supply to the heavy-duty vehicles sector, where it was anticipated to displace diesel fuel.

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, while digester gas refers to the production of biogas from wastewater treatment plants (sewage), and livestock manure, food waste, industrial waste, and other sources. Biogas, like other forms of natural gas, can be compressed or liquefied, or converted to hydrogen. Biogas can also be injected into a natural gas pipeline. Because biogas is made from waste, It has a very low carbon intensity.

Natural gas and biogas also offers economic benefits to the US economy over petroleum consumption. Most natural gas is domestically produced, allowing the positive economic and employment benefits from production, processing, distribution and sale to be fully captured within the US economy. By contrast, the US economy imports approximately two thirds of its petroleum for use in the transportation sector. In addition, a significant infrastructure for processing and distributing natural gas products already exists in the form of pipeline networks serving the utilities sector. This cost-effective infrastructure, along with low projected costs of extraction, produces a very low retail price (projected to be only around 60% of petroleum fuels) and significant fuel savings to consumers, businesses and governments.

Hydrogen

Hydrogen fuel is yet another alternative fuel offering lower carbon emissions per mile of vehicle travel. Emissions from the use of hydrogen fuel are extremely low, and can constitute no greenhouse gas emissions at all. However, hydrogen fuel does require energy-intensive processes for its formulation. Several approaches exist, usually using fossil fuels to isolate and store hydrogen in fuel cells. This process, rather than the actual use of the fuel in a vehicle, is where the associated emissions are generated.

Despite these associated emissions, the EPA and AEO associate hydrogen with fewer emissions per unit of energy than either diesel or gasoline. In addition to this benefit, the vehicular efficiency (how far the vehicle can go on the same amount of energy) is projected to be much greater for these vehicles than for conventional vehicles. As such, hydrogen achieves two benefits: it reduces the emissions associated with energy use and achieves greater distance traveled on the same amount of energy.

Hydrogen technology is, however, in its infancy. Excess supply from industrial production of hydrogen is not considered to be sufficient to supply fuel to a significant share of the vehicle fleet or to displace a significant amount of petroleum fuels. Developing the production capacity, vehicle technology and distribution infrastructure is considered to be at best a long-term goal, and expansion of a hydrogen transportation industry is viewed as unrealistic over the period of analysis considered in this project.

Expected Economic Impacts in Oregon

This economic analysis of potential Low Carbon Fuel Standards 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 standards. The purpose of the standards 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, biodiesel, natural gas and electricity. The different 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.

Regardless of the fuels modeled, the importance of production within the United States, and possibly within Oregon, is economically very significant. The importation of petroleum products to the nation and to Oregon results in a negative balance of trade for the nation and for Oregon and reduces economic performance. Domestic production, by contrast, allows the domestic economy to retain the wealth spent on feedstock.

In a 2005 study for the US Department of Energy, researchers at Oak Ridge National Laboratories estimated that if oil prices in 2005 averaged $35-$45/bbl, oil dependence costs in 2005 will be in the range of $150-$250 billion.[3] By reducing petroleum imports and replacing

[3] COSTS OF U.S. OIL DEPENDENCE: 2005 UPDATE, David L. Greene, Oak Ridge National Laboratory and Sanjana Ahmad, University of Tennessee, February 2005, for the U.S. DEPARTMENT OF ENERGY

the fuel with low carbon domestic alternatives, there is an opportunity to reduce these economic losses from the US and Oregon economy.

Other Economic Impact Studies

There have been several recent economic or macroeconomic impact analyses focusing on scenarios involving the implementation of an LCFS, or of some fuel-related strategies commonly found within an LCFS. The authors of these studies 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 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, NESCAUM[4], the California Climate Action Team, and Charles River Associates. A comparison of these studies is found in the Oregon Low Carbon Fuel Standards Report as Appendix E: Comparable Economic Studies in Other States Memorandum.

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. Those of high similarity should be more valuable to those considering an LCFS in Oregon.

Studies Reviewed

Study	*Date of Publication*	*Similarity to Oregon Study and Usefulness for Comparison*
Impacts of Comprehensive Climate and Energy Policy Options on the U.S. Economy *Center for Climate Strategies and Johns Hopkins University*	2010	Limited. Considers macro effects of biofuels, but only as part of a 23-policy bundle. Analysis is done a) on a national scale and b) without detailed infrastructure assumptions
The Economic Impact of the Florida Energy and Climate Change Action	2008	Somewhat. A state-level study with macroeconomic analysis, finding $15 billion in direct savings from advanced

[4] NESCAUM stands for Northeast States for Coordinated Air Use Management.

Plan on the State's Economy *Adam Rose and Dan Wei, University of Southern California*		biofuels use. No macro analysis was completed for the biofuels strategy, however, beyond a projection of 11,000 net positive new jobs created.
Washington State Low Carbon Fuel Standard Analysis *Washington State Department of Environmental Quality*	Ongoing	Superior, but not yet complete. This study uses very similar methodologies and uses very similar sets of inputs and an equivalent LCFS scenario. Scenarios and assumptions differ only in minor ways from those in the current study. This study is not yet completed.
Northeast States Low Carbon Fuel Standard Analysis *NESCAUM*	Ongoing	Significant, but not yet complete. This study undertakes very similar methodologies and uses very similar sets of inputs. Scenarios may differ; they have not yet been established. This study is in its beginning stages.
Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report *California Climate Action Team – Economics Subgroup*	2006	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.
Economic and Energy Impacts Resulting from a National Low-Carbon Fuel Standard *Charles River Associates*	2010	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 capacity is impossible within the next 15 years, and thus models no change in the use of alternative fuels. The likelihood of its other assumptions is open to question on political, technological and economic grounds.
California Air Resources	2009	Somewhat. CARB's analysis considered

Board, Economic Impact Estimate of Low-Carbon Fuel Standard		a similar LCFS standard and also considered several alternate scenarios to achieving that standard over a 10-year period. However, their economic analysis was limited to direct microeconomic impacts, rather than a wider macroeconomic analysis showing the effect on the economy as a whole.
National Low Carbon Fuel Standard Analysis *University of California, Davis*	Ongoing	Unclear. Researchers seek to complete a macroeconomic analysis of a national LCFS scenario, but the scenario design is not yet complete and the analytical methods have not yet been publicly described.

Methodology

Measuring Economic Impacts

Impact analyses are always framed within the context of "with" and "without" (benchmark) perspectives. The impact of an exogenous event, such as the application of an LCFS policy, is defined and measured in terms of the differences between the state of the economy associated with the change and its state without. Thus, impact analysis requires the ability to forecast a baseline condition. In *ex post* analyses, the only forecast required is of what the economy would have been without the change, since the state with the change is directly observable. In *ex ante* analyses such as the present study, research is required to estimate what the economy is expected to look like in both the "with" and "without" scenarios. This framework is required whether the analysis is qualitative or quantitative. Impacts cannot be ascertained otherwise.

All impact analyses require an explicit or implicit model that explains how the economy is affected by a variety of factors determined outside the control of private decision makers. Because there is a wide range of opinions on the likely direction of energy use, it may be wise to define alternative benchmark scenarios that will meet the LCFS mandates. In order to complete the analysis of the Oregon LCFS scenarios, the project team created a baseline that includes not only the fuel mix today, but the mix in each year between the current year and a forecast year without the potential Oregon LCFS. The end year for this analysis is 2022. This baseline is

developed from the US Department of Energy Annual Energy Outlook with major modifications based on discussions with the low carbon fuel advisory committee and TIAX. In future studies, DEQ might want to consider a longer term as well, such as 2030 or even 2050. The longer term horizon might reveal trends that are not anticipated. For example, hydrogen fuel is unlikely to play a role in meeting the 2022 goal, but may be an important option in the longer term. This analysis develops baseline and annual alternative impacts only over the period from 2012 to 2022.

Many issues must be considered in the baseline, including the underlying growth in Oregon population and economic activity. The most recent Oregon Economic Review and Forecast[5] expects annual employment growth over the next decade to be between one and two percent with annual growth in per capita income of about three percent. This growth in income and employment will include expected growth in demand for gasoline and diesel fuel to power transportation. Because of the State of Oregon and City of Portland renewable fuel standards, similar growth is expected for biofuels. These expectations are in the baseline scenario (referred to as the "Business As Usual" or "BAU" scenario). The baseline scenario changes will proceed in a dynamic fashion, the pace of which will be crucial in defining the impact and viability of a lower-carbon-intense-fuel-driven Oregon economy. Note that there are both microeconomic and macroeconomic baseline considerations. As such, both the VISION (vehicle inventory and use) and REMI (Input-Output, Computable General Equilibrium, and economic Geography models) tools must generate a baseline from which scenarios under consideration can be evaluated in later steps. These modeling tools and their application are discussed below.

Types of Economic Impacts

The estimation of economic impacts of public policy often focuses on three types of impacts. Direct economic impacts refer to the changes in behavior and costs that result from actions to comply with the LCFS. For example, the development of distilling resources to produce fuel ethanol would be a direct impact. Indirect economic impacts are defined as the behavior and costs that result in the economy to facilitate the direct impacts. An example of indirect impacts is the economic impact resulting from the likely changes in spending on labor and fertilizer, which are needed to produce crops that will serve as feedstock for an ethanol production facility. The labor and materials needed to build and run such a facility are another indirect impact. Finally, induced economic impacts are the behavior and expenditures by households given the changes in income earned as a result of both direct and indirect activities. Induced impacts may occur across the entire economy.

Most environmental regulations result in higher production costs for the regulated industries. Tailpipe emissions regulations require additional vehicle emissions control technology which

[5] http://www.oregon.gov/DAS/OEA/economic.shtml#Most_Recent_Forecast

increases the production cost of the vehicle. Air quality regulations that limit plant emissions require production modifications or emissions post production processing to comply with emissions limits. The additional cost of compliance is compared to the benefits of reduced emissions such as improved health and quality of life. If the benefits of the regulation are deemed to exceed the costs, the regulation is considered cost effective.

The proposed Oregon LCFS is distinct in its economic impact from typical environmental regulation, as it provides an opportunity for economic gains as domestic and in-state production of replacement fuels stimulates the US and Oregon economies. This stimulus results from a reduction in petroleum imports and an increase in domestic investment to provide feedstock and production/generation facilities for the replacement fuels. In this study, all alternative fuel supply investment within Oregon is deemed to come from outside the state as there is now no significant transportation fuel production industry in Oregon. This external investment in productive facilities in Oregon creates employment, income and state product greater than would exist without this stimulation.

The potential decision by Oregon to institute an LCFS will provide opportunities for economic development within Oregon that would not occur in the absence of such a rule. Such investments will not occur in the absence of the rule, as investors would have no guarantee that the market for alternative fuels would materialize. Indeed, the petroleum sector could modify delivery prices in areas where such investments were made to make these investments uneconomic. However, with the rule in place, low carbon fuel suppliers are effectively guaranteed a market for their product as the fuel mix is required to meet the carbon intensity requirements of the regulation. Without a supply of these low carbon substitutes, traditional petroleum could not be sold in the Oregon market.

The level of investment assumed in the macroeconomic model is considered fixed in the baseline. Thus, new investment from outside of Oregon will increase economic activity in Oregon in the scenarios. This is particularly true in the short run as there is very little transportation fuel produced in Oregon today. If these investments, or even a portion of these investments, came from within Oregon, they would replace other Oregon investments. The economic impacts would then be measured as the impacts of the new investment less that of the displaced investment. This is a complicated calculus and has not been carried out in this analysis. If it had been, the measured economic impacts would likely still be positive, as only a portion of the investments would displace existing investments and the impacts of the displaced and new investments are likely to be similar in aggregate. Also, regardless of the source of the investment dollars, the LCFS policy (under most scenarios) would achieve a displacement of imports by domestically produced fuels, which allows the state to gain economic benefits associated with the production and sale of fuels – benefits currently enjoyed almost exclusively by out-of-state providers.

This analysis considers impacts to over 70 distinct sectors of the economy. The nature of the expected impacts under the scenarios considered suggested that certain specific sectors would be likely to see significant impacts. The anticipation of the construction of new biofuels refining facilities suggests likely gains for the construction sector. Because construction is labor-intensive work (when considered in terms of the number of full-time-equivalent positions per dollar expended in the sector), employment was also anticipated to rise, and as a further consequence, incomes and consumer spending were expected to rise as well. Petroleum production would be expected to show a loss in economic activity as alternative fuels displace gas and diesel, but in Oregon's case, the state has no in-state production or refining, and so such an impact was not expected here. Even in the State of Washington, where they have a sizeable petroleum production economy, their economic analysis showed net economic benefits in all of their scenarios except for the one where all fuel production came from out-of-state sources.

The modeling and analyses produced results which agreed with those assumptions. The sectors in which the largest impacts are projected to occur under the different scenarios are described in the Macro Modeling section (see below).

Scenario Development

Purpose of Scenario Analysis

This scenario analysis is not a forecasting effort. Forecasting economic conditions in a particular year is a challenging prospect. Projections of future economic conditions depend on the expected growth in population and in economic activities, but are subject to the effects of natural, economic and political conditions during the forecast period that are impossible to predict with precision. Natural disasters, international banking collapse, war, embargos and many other unpredictable events will determine the future level of economic activity. The best that can be done is to develop a state economic forecast that is consistent with the national forecast and recognizes any unique characteristics of the Oregon economy. This forecast is the business-as-usual scenario, without a LCFS either in Oregon or nationwide. Fortunately, this analysis of a Low Carbon Fuel Standard requires only a baseline, and not a full economic forecast, to assess the impacts of the standard.

The transportation fuel supply industry in Oregon will have a range of options available to it to supply transportation fuel to the state while meeting the LCFS. These options are referred to as compliance scenarios. The DEQ, working with the low carbon fuel advisory committee and TIAX, developed a set of compliance scenarios that are believed to bracket the range of potential fuel supply options. All of the selected compliance scenarios result in compliance with the

LCFS, and they are expected to bracket a range of realistic assumptions regarding the low carbon fuels available in the future. Scenario analyses were conducted for gasoline and diesel fuel, both separately and in a single fuel pool.

Impacts are measured by comparing each scenario to the baseline business-as-usual scenario. The direct, indirect and induced impacts are catalogued for each scenario compared to the baseline for macroeconomic variables such as employment, personal income and state product.

Carbon Intensities

The process of identifying scenarios in which alternate fuel use leads to a certain level of change in carbon intensity depends on an understanding of the relative carbon intensities of different fuels. Analysts utilized carbon intensity calculation methods developed by Argonne National Laboratories as part of its GREET model. These carbon intensities represent the amount of greenhouse gases a fuel is expected to produce for a fixed unit of energy (this is most commonly measured in grams per megajoule). Different fuels have different amounts of energy in the same volume, so comparisons by gallon can be misleading, and inapplicable as a measurement for non-liquid fuels such as electricity and compressed natural gas. Comparing by units of energy allows fuels of very different types to be compared on similar footing.

Carbon intensities were developed for gasoline, diesel, natural gas from fossil sources, and electricity. Carbon intensities for biomass-based diesel and ethanol were further refined to differentiate between all the different biofuels pathways under consideration as part of the scenarios in this analysis. Separate carbon intensities were developed for each of the following:

- Midwest corn ethanol, refined in Midwestern refineries and transported to Oregon
    - Conventional varieties
    - Lower-carbon varieties
- Midwest corn ethanol, made with Midwest corn but refined in Oregon
- Cellulosic ethanol from waste food
- Out-of-state cellulosic ethanol
- Imported sugarcane ethanol from Brazil
- Cellulosic ethanol from forest residue and from grass waste
- Cellulosic ethanol from wheat straw

- Cellulosic ethanol from farmed trees
- Midwest-produced biodiesel from soybean stock
- Northwest-produced biodiesel from canola
- Northwest-produced biodiesel from waste yellow grease
- Northwest-produced renewable diesel from camelina
- Cellulosic diesel
- Compressed natural gas from waste biogas

All carbon intensities, including those for both gasoline and diesel, were then weighted by projections of vehicle efficiency (miles driven on the same amount of energy as is contained in a gallon of gas) as compared to a conventional gasoline or diesel vehicle to develop carbon intensities for each fuel. This step was taken to allow the comparison to account for the projected transportation efficiency of fuels. As mentioned above in the section describing electrification and the use of natural gas as an LCFS option, different fuels are associated with engine technologies which have different efficiency ratings. Applying this adjustment allows for the measurement of carbon intensity per mile traveled, rather than just a measurement of carbon intensity from production, transportation, refining, storing and burning fuel.[6]

Scenario Selection

A compliance scenario combines information from a fuels assessments and the calculation of carbon intensities to estimate the volume of various low carbon fuels that would be needed to achieve the LCFS. 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 LCFS 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 LCFS phase-in schedule in light of expected fuel availability and identify investment

[6] This analytical step, if enshrined in policy, has the potential to create an incentive for fuel providers and vehicle manufacturers to pursue vehicle efficiency technologies. Under such a policy, improvements in vehicle efficiency of specific models would make the fuels powering those vehicles more attractive for compliance with an LCFS policy.

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.

Based on discussions with DEQ and the low carbon fuel standards advisory committee, TIAX created an Oregon-adjusted business-as-usual case. It assumed that Oregon receives its proportional share of 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. It also assumed continuation of the Oregon Low Emission Vehicle program as well as federal fuel economy standards currently 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% reduction in carbon intensity by 2022. For each scenario there were separate analysis (Runs) for light duty and heavy duty vehicles. The eight scenarios are listed below.[7]

Scenario A – Cellulosic Biofuels with Indirect Land Use Change

Cellulosic Ethanol with indirect land use change (Produced In-State)

- In addition to Northwest corn ethanol and waste berry ethanol, compliance with standards achieved through use of in-state cellulosic ethanol. A small amount of out-of-state cellulosic ethanol is included due to lack of additional in-state feedstock availability.
- If more ethanol is needed to reach total RFS2 proportional share volumes, it comes from Midwest corn ethanol.

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

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 (some produced in-state, a small amount from out-of-state).

[7] Scenario descriptions developed by DEQ and TIAX, LLC

- 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.

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-based 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

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, in-state cellulosic ethanol, and some cellulosic ethanol produced out-of-state.
- For comparison with Scenario B, we increased the blend wall to E12 in 2017 and E15 in 2020.

Conventional Biodiesel without indirect land use change

- Compliance achieved through:
  - Existing canola biodiesel
  - Existing waste oil biodiesel
  - Midwest soybean biodiesel

Scenario D – Electricity, CNG and Cellulosic Biofuels with Indirect Land Use Change

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 Scenario A except more electric vehicles to substitute for light duty gasoline are included, so less ethanol is required.

Maximize CNG vehicles and cellulosic diesel with indirect land use change

- Similar to Scenario A except more CNG vehicles to substitute for heavy duty diesel are included so less biodiesel is required.

Scenario E – One Pool

In this scenario, all fuels are treated as a single pool for compliance purposes. Heavy-duty vehicles achieve disproportionate gains. Multiple new fuels sources are combined,

including ethanol and biodiesel along with electric vehicles, plug-in hybrids, and expanded use of CNG in trucks.

Scenario F – Mixed Biofuels without Indirect Land Use Change, high oil prices

- Similar mix of fuels as Scenario C, but with higher oil prices (compared against a baseline also modified to reflect higher oil prices).

Scenario G – Mixed Biofuels without Indirect Land Use Change, low oil prices

- Similar mix of fuels as Scenario C, but with lower oil prices (compared against a baseline also modified to reflect lower oil prices).

Scenario H – Cellulosic Biofuels with Indirect Land Use Change, Out-of-State

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.

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 LCFS. Instead of using 2022 as the end point of the LCFS, 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% 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 LCFS. 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. For this analysis, the low carbon fuel standards advisory committee chose to adjust the carbon intensity of biofuels with California Air Resources Board's indirect land use change (or "ILUC") estimate. The CARB estimate is the highest of those

available (the EPA also produced estimates of carbon emissions attributable to biofuels as a result of indirect land use change numbers for the RFS2 program, and Purdue University also has a new estimate for ILUC-driven carbon emissions from corn ethanol). There is no consensus establishing that one estimate is better or more accurate than the others. 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. This analysis provides some information on the significance of its effect that the advisory committee members could use to inform their recommendations to DEQ.

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. Certain assumptions were made in order to estimate the amount of alternative fuels Oregon should expect to receive. 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 were necessary regarding the amount of ethanol that would be blended into gasoline during the 2012-2022 period. The current blend of 10% ethanol and 90% gasoline, known as E10, was retained for this analysis. A higher blend wall, allowing up to 15% ethanol, would create a higher baseline for ethanol use. A lower blend wall would need more ethanol to be used in flex-fuel vehicles capable of using up to 85% ethanol blend. The State of Washington's LCFS analysis assumed that a statewide ethanol blend of 15% ethanol would be in place in the future. The Oregon advisory committee recommended by consensus that E10 be the blend wall for this analysis (except in one case where it was necessary to increase the blend wall to E12 then E15 over time in order to consume all of its RFS2 proportional shares). The effect of this recommendation is that Oregon's program assumes the higher cost of developing the infrastructure needed to support a larger E85 fleet.

VISION Modeling

The VISION Model, developed by Argonne National Laboratories, is a spreadsheet-based tool that seeks to measure energy and greenhouse gas emissions from the entire US on-road vehicle fleet. It relies on perpetual inventories of 22 different classes of light-duty vehicles (eleven each for autos and light trucks), as well as six different classes of heavy-duty vehicles. The tool allows for extensive customization of the assumptions underlying the types of fuel used, the types of vehicles entering the market, the carbon intensities of each type of fuel, and the extent to which various fuels are blended together.

The standard tool was extensively modified to reflect Oregon, rather than the entire US, before any analyses were completed. The vehicle fleet was adjusted in both size and composition to reflect state rather than national data. Fuel price data and projections were adjusted to reflect projections for the Pacific region, rather than national average projections.

For each scenario, analysts developed a detailed picture of the exact sources from which various fuel supplies would be obtained. The model was expanded to reflect this detailed picture of the scenario's fuel supply, and the carbon intensities used were adjusted to reflect the scenario's unique mix as well.

Assumptions

Key assumptions in the VISION analyses, beyond those related to developing the LCFS scenarios, are as follows:

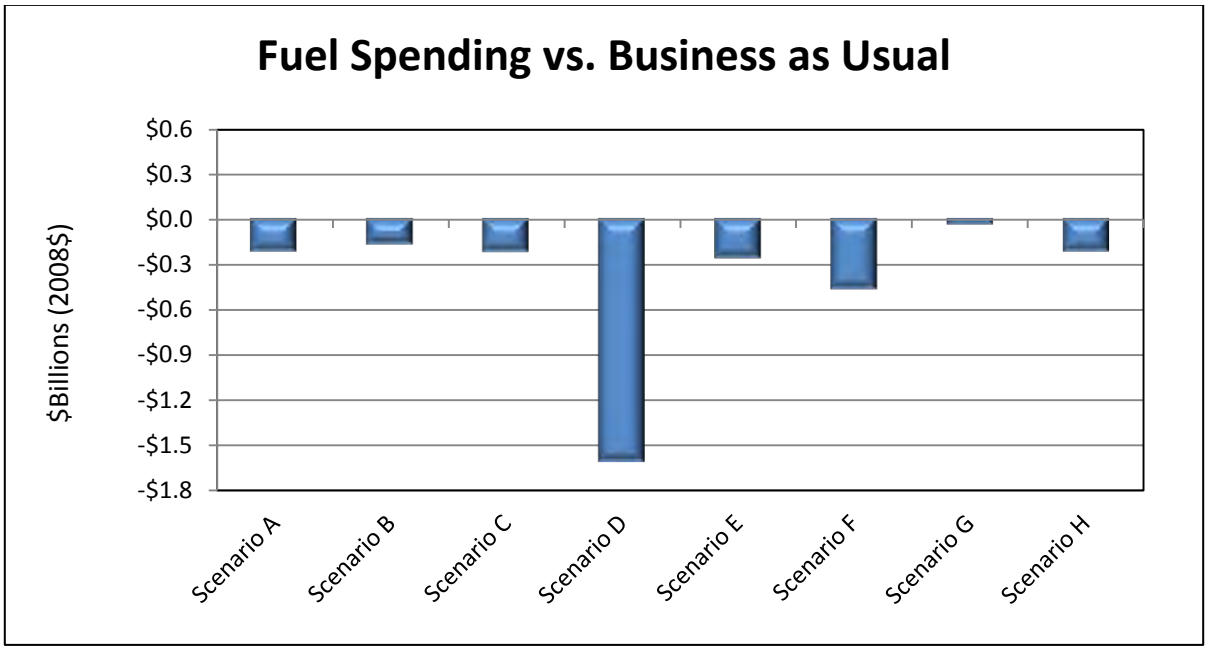
- Fleet composition – number and percent of each type of vehicle comprising the heavy-duty and light-duty fleets
- Fuel efficiency – miles per gasoline gallon equivalent achieved by each type of vehicle in the heavy- and light-duty fleets.
- Fuel and Vehicle prices – projected costs of each type of fuel, including taxes, as well as projected prices for each type of vehicle comprising the light-duty fleet.
- Carbon intensity – full lifecycle carbon intensities for conventional fuels (diesel and gasoline) as well as alternative fuels (natural gas, electricity, biofuels)
- Vehicle duration and scrappage – rates at which vehicles leave the fleet as they age.

Assumptions are outlined in the Oregon Low Carbon Fuel Standard Report in:

- Appendix B: Lifecycle Analysis
- Appendix C: Infrastructure Cost Assumptions
- Appendix F: Compliance Scenario Documentation.

Results

VISION analyses produce extensive results regarding a wide variety of impacts in each scenario, such as the volumes of various fuels consumed, the projected expenditure on those fuels, the blends of various fuels and the costs of any alternative vehicles required. An extensive collection of results is presented in Appendix A of this report. One representative result, the projected spending change on fuel under each of the eight scenarios, is depicted in the chart below:



VISION to REMI

While the VISION model is a valuable tool for measuring the impacts of changes to vehicle fleets and fuels, it does not produce macroeconomic impacts that show how such changes might reverberate through the broader economy. Significant increases in the consumption of biofuels, particularly of biofuels produced in-state, can be expected to impact farming and agricultural sectors of the economy. Significant shifts away from petroleum-based fuels (gasoline and diesel) can be expected to have impacts on businesses involved in oil production, refining and transportation. Significant new utilization of natural gas or electricity produced in-state would also affect related industries. Macroeconomic models seek to estimate these broader impacts.

For this project, the study team utilized the "REMI PI+" model, produced by Regional Economic Models, Inc.

Also, VISION provides only some of the values necessary to fully inform the REMI PI+ model of the direct economic expenditures expected under the different scenarios. To provide necessary inputs, analysts (with input from the low carbon fuel standards advisory committee) developed estimates for a number of direct expenditures expected as part of each different scenario. The expenditures included:

- New refining capacity for ethanol and for biodiesel
- Labor, utilities and feedstock costs for new refinery operations
- Distribution and fueling infrastructure (including additional tanker fleet costs) for additional biofuels and natural gas
- Fueling infrastructure and additional vehicle costs for electric/plug-in hybrid-electric fleet
- Additional vehicle costs for natural-gas powered heavy-duty vehicles

Further, VISION produces many of its results in physical units, such as gallons of fuel or BTUs of energy. The VISION to MACRO process involved developing direct economic impact estimates under each scenario for fuel expenditures based upon Department of Energy fuel price projections.

Assumptions and Results

Macro- and micro-economic models seek to evaluate economic activity at two very different levels. Micro analysis is concerned with activities for individuals or small groups of economic factors such as households, firms or agencies.

In this case, the modeling seeks to understand how the demand for transportation fuel is impacted by vehicle technology changes, driving patterns and fuel choice. VISION includes a full accounting of these decisions in the base year and in each forward year through 2022. It keeps track of the fleet over time so that the amount of fuel used, by type, is accounted for.

Macroeconomic models are broad aggregates of the economy. Sectors in the macro model include many products and industries collected and measured together. For example, there is no unique gasoline industry. Gasoline production is included in the Sector: *Petroleum and Coal Production*. Thus, both micro and macro models are required to simulate the economic impacts of the LCFS. These models can be separate stand-alone models or they can be combined in a

single program that translates and transfers the micro changes caused by this regulation to the macro model. In this case, we took advantage of the microeconomic detail of the VISION model and the capacity for macroeconomic aggregation of the REMI PI+ model. Other individual and combined models are available, but none offers more detail than those applied.

The full list of results and assumptions is included in Appendix B.

MACRO Modeling

Assumptions

The macroeconomic analysis was accomplished with the use of the REMI PI+ model. First, the business as usual case was run for Oregon using the REMI default case. Then, a model run was conducted and the results were compared to the baseline BAU for each scenario. The analysis focused on the change in employment, personal income and gross state product, but more detailed comparisons are available for each economic sector characterized in the 70 sector REMI as well as all categories of final demand.[8]

PI+ Results

The eight compliance scenarios were designed by DEQ and the advisory panel to include a wide range of potential compliance scenarios for the Oregon fuel supply sector. The graphs below indicate how macroeconomic variables such as income, employment and state product vary across scenarios. All three macro variables move together as the scenarios alter the low carbon fuel mix. In all cases the Oregon economy and fuel supply system is treated as the responder to the LCFS as it purchases and supplies the needs of Oregon vehicles for fuel that meets the standard. No national LCFS is assumed. The potential supply of fuel from each source is determined in the scenario and limited if there is a capacity constraint.

All scenarios that rely on liquid fuels demonstrate similar macro impacts. Investment in new plants and equipment to produce these fuels and the required infrastructure stimulates the Oregon economy in the years when plants are built and in their continuing operation. Baseline conditions are developed from the US Department of Energy AEO report and the base case

[8] Final demand is the total demand for final goods and services in the economy.

scenario is built into the REMI models. Positive economic impacts in Oregon stem from the importation of less petroleum fuel and its replacement with Oregon produced products. To the extent that the Oregon LCFS reduces national petroleum imports, similar economic impacts will be realized. It should be noted that the level of petroleum consumption reduction in Oregon will not result in a lower absolute value for petroleum imports to Oregon then are imported today as demand growth is expected to continue through 2022. In the longer term, improved internal combustion efficiencies associated with new higher Corporate Average Fuel Economy (CAFE) regulation is expected to result in lower petroleum consumption in 2030 than the amount consumed currently.

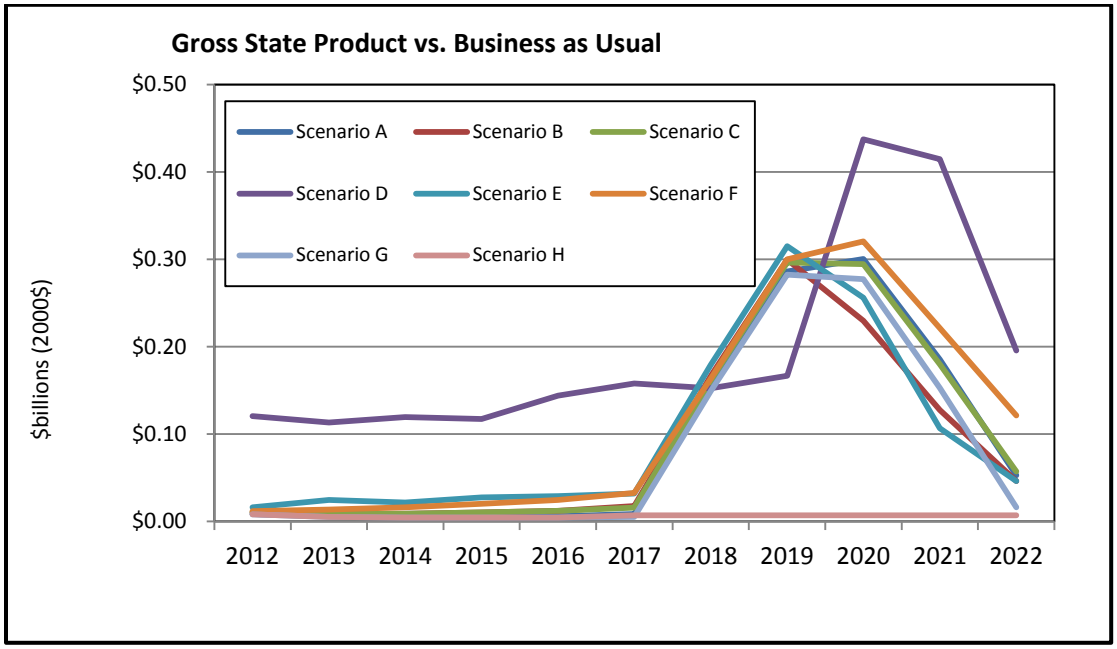
The results from Scenario D suggest that meeting the LCFS with electric vehicles in the light duty market and natural gas powered vehicles in the heavy duty market provides an earlier economic benefit than liquid fuel options through higher effective vehicle efficiencies. The US and California low emission vehicle standards and other forces are leading to the introduction this year of several electric-powered vehicles by both US and foreign automobile producers. The presence of pre-existing forces encouraging the development of an electric-vehicle fleet may allow the Oregon population to reduce their petroleum demand through this avenue more readily than through other alternative-fuel options.

The macroeconomic modeling analysis produced estimates of overall economic impacts, as well as specific impacts to approximately 70 different sectors of the economy, for all eight different compliance scenarios. The full results are included in this report as Appendix C.

All scenarios show net economic growth, but the final scenario, assuming all alternative fuels to be imported, shows very little economic change at all. This is due to the decision to assume that all of the capital investment will come from outside the state of Oregon and was based on the fact that the state currently has a very small domestic industry that produces transportation fuels. An analysis that considered this new capital expenditure as being taken from other capital-investment opportunities within the state would likely show more economic losses. This analysis, however, assumes that the lost capital investment occurs almost entirely out of state.

Gross State Product

The first graphic demonstrates the change in gross state product (GSP) projected under each scenario.



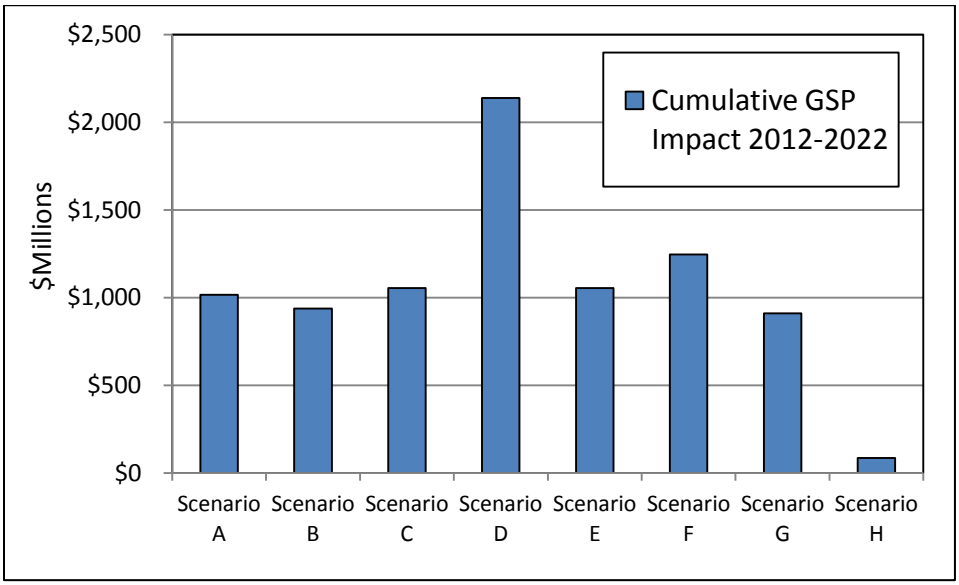
The graphic above depicts the GSP impacts of each of the eight scenarios modeled. In every scenario, the overall GSP changes are positive, indicating that the scenarios drive growth in economic activity in the state.

Results for six of the eight scenarios (scenarios A through C and E through G) produce a very similar projection, indicated by the six closely grouped lines in the graph. These scenarios all produce minor changes to GSP for the first five years of policy implementation (2013 to 2017), followed by rapid rises in the GSP impact in 2018 and continuing through 2021. This sudden increase in scenario impact corresponds to the beginning of construction of plants for the refining of biofuels. This construction, assumed to start only after a few years due to the time requirements of necessary preliminary steps such as design, permitting and site selection, represents a significant infusion of money into the state's economy.

Scenario D, which envisions an approach more focused on electricity and natural gas than on biofuels, produces a larger GSP impact and a different GSP impact pattern. This is represented by the high purple line. Unlike other scenarios, positive GSP impacts begin immediately, due to the expected on-going investment in electrical charging stations. This investment can begin immediately. Some in-state biofuels refining remains part of the scenario, and so the GSP impact of Scenario D spikes upward late in the period. As with other scenarios, this reflects investment in the construction of a refinery.

Scenario H, which envisions reliance on biofuels provided entirely from out-of-state agriculture and out-of-state refining, produces the lowest impact on GSP. The flat line in the graph represents this scenario. With little investment change in the state, and little change in overall fuel spending, this scenario produces very small changes from the business-as-usual projection.

The graphic below shows the overall volume of GSP change from the baseline in each scenario for the entire 10-year period in which the LCFS would ramp up to full implementation:



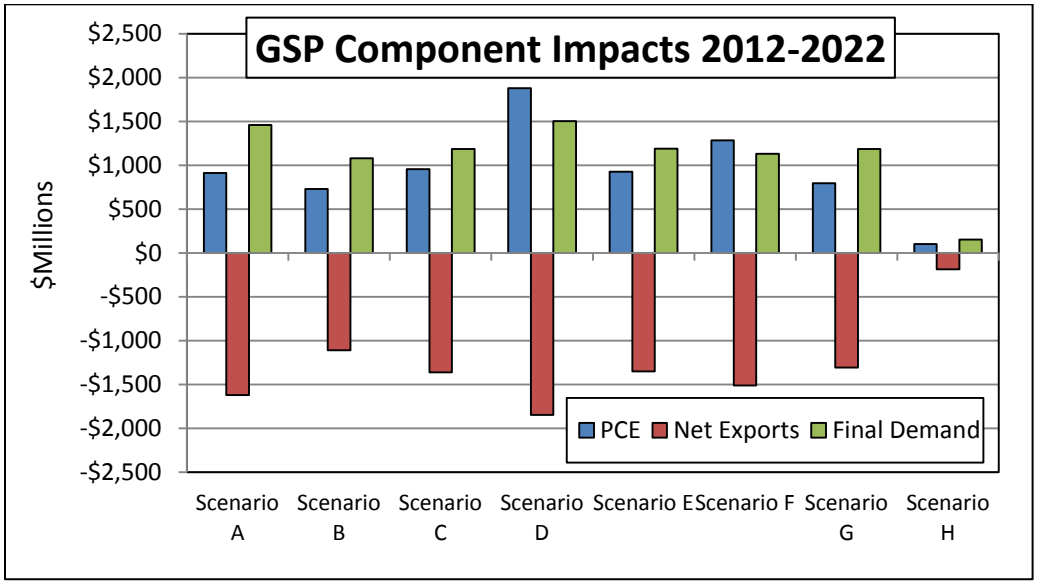
Overall, the six scenarios involving in-state production of biofuels (A through C and E through G) have fairly similar GSP impacts, ranging from approximately $900 million to about $1.25 billion in additional economic activity. Differences in the projected prices of fuels and the types and volumes of fuels needed are responsible for the variation among these six scenarios. Scenario D, which produces higher GSP impact projections every year, has a similarly higher cumulative effect. Scenario H, which never has a large impact in any single year, has a small cumulative effect.

Gross State Product Components

Gross State Product is estimated by measuring several components of activity in the state's economy. Levels of consumer spending, private sector investment, inventories, imports and exports, and government spending are among the components that make up a state's overall GSP.

The analysis of the LCFS scenarios identified three GSP components consistently expected to show significant impacts. Those components are Personal Consumption Expenditures, Private

Domestic Investment, and Net Exports (which represents the value of goods exported after deducting the value of goods imported).



In all scenarios, net exports (indicated by the red columns) fall against the baseline as a result of the increase in imports required. These imports are components of the capital to be constructed. However, this change (measured as a loss of GSP) is offset by increases in demand (indicated by the green columns) in every case. While these two components largely offset each other, personal consumption rises in every scenario, helping to drive the positive overall GSP change.

Two other GSP components, government expenditures and private domestic investment, also rise in every scenario, but at a much smaller scale.

Changes in Output and Value Added by Sector

Output is a measure of the total production in each sector, including a) intermediate consumption as an input to other products, b) final consumption as an end product by households, and c) the amount exported to non-Oregon markets for consumption.

Value Added has many components, the key ones associated with compensation of labor and return to capital.

REMI PI+ modeling produced estimates of the change in output for 70 individual sectors (see appendices for all sector outputs). Of these 70 sectors, the changes in output and value added were consistently largest in nine sectors in particular. Those nine sectors are:

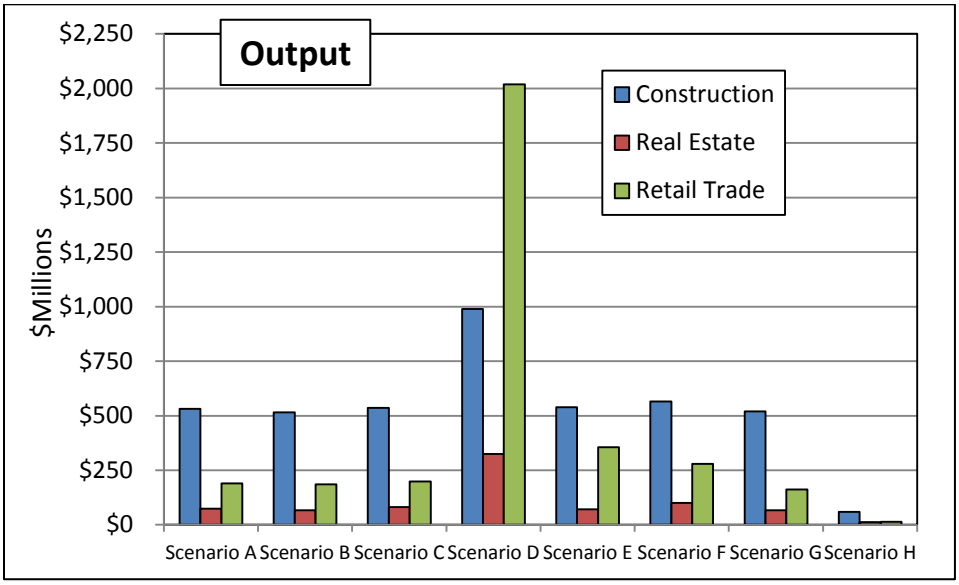
- Construction

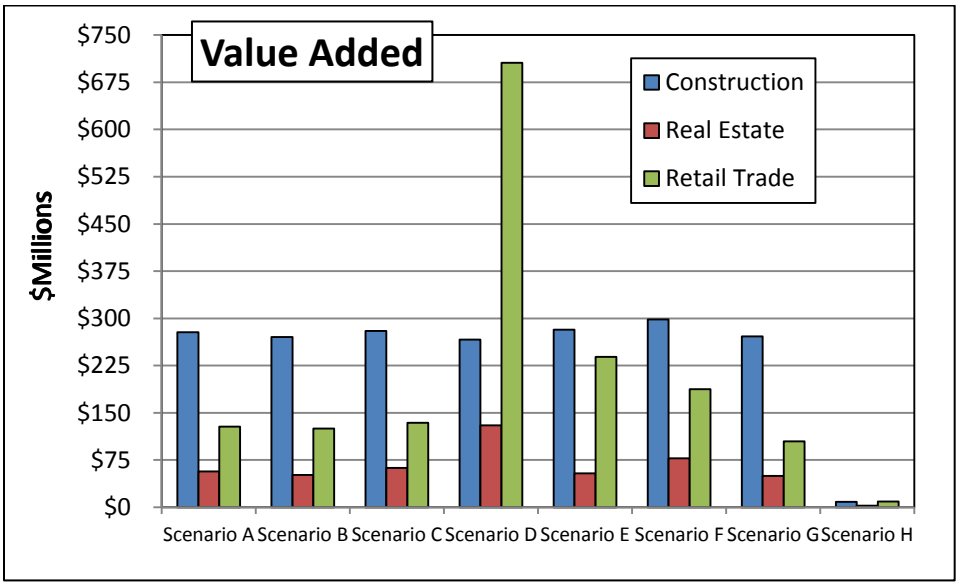
- Real Estate
- Retail Trade
- Wholesale Trade
- Professional Services
- Healthcare
- Banking
- Waste Management
- Administrative Services

Each of these sectors saw an impact of over $50 million in additional volume above the baseline in at least one scenario. It is valuable to observe that no one of these nine specific sectors modeled in this analysis saw significant negative impacts as a result. Also, no sector was projected to experience negative impacts of a size on the scale of the positive impacts identified in these nine.

Notably, the sectors of petroleum production and agricultural production were not among the sectors projected to experience significant economic impacts under these scenarios. Oregon produces no petroleum fuel in-state, and so the losses incurred to the petroleum sector would be felt elsewhere in the country. Agriculture is impacted, but other sectors see larger changes due to their connection with the new spending on construction of biofuels refining facilities. Because that spending represents the great majority of the economic activity associated with LCFS compliance, sectors most affected by it show the largest impacts.

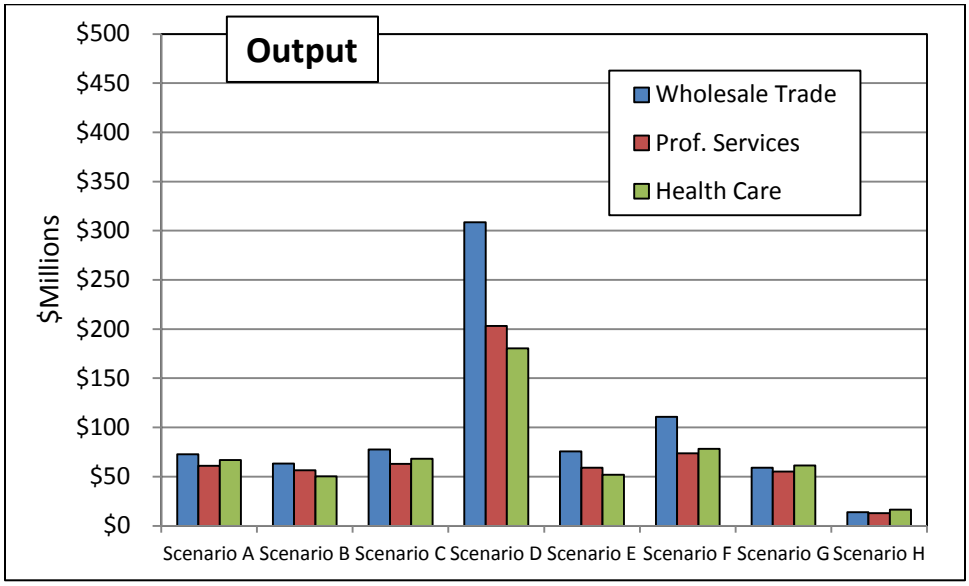
The sectors registering the largest impacts are the construction, real estate, and retail trade sectors.

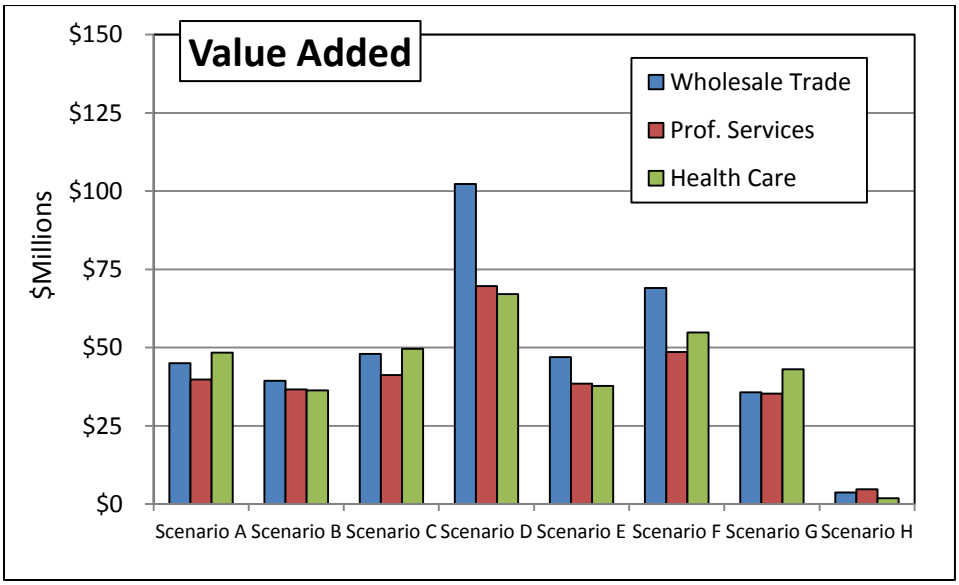




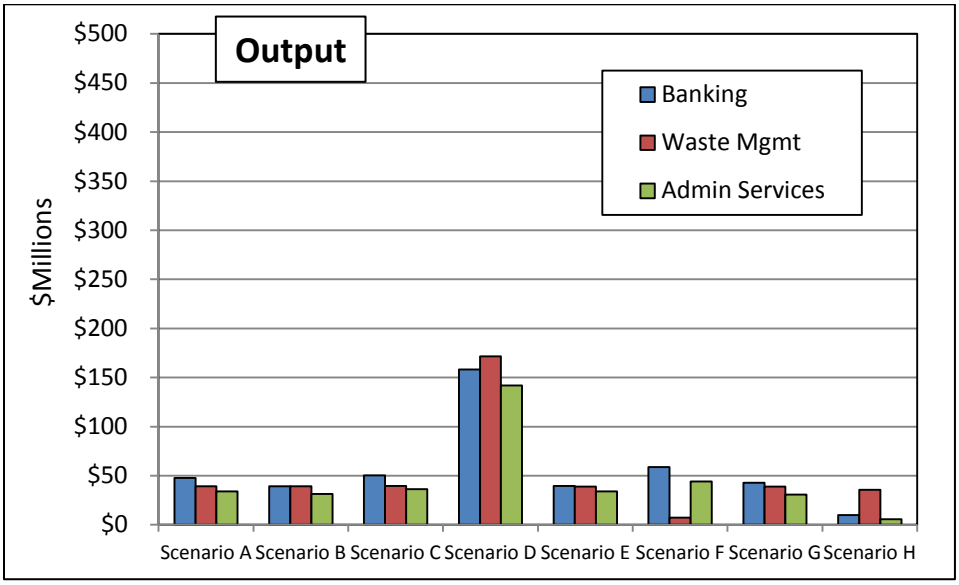
The construction sector impacts are similar in all scenarios with biofuels plant construction assumed to occur (all scenarios except H). Retail trade and real estate are similar in the same scenarios with the exception of Scenario D. Scenario D stands out in that the positive impacts in the retail trade sector are magnified. Retail fuel expenditures fall significantly in scenario D, as a consequence of the lower price of energy when supplied in the forms of electricity and natural gas. This leaves greater room for consumer expenditures on other categories of goods and services. Overall, the changes to ouputs for these three sectors are roughly twice as large as the changes to value added.

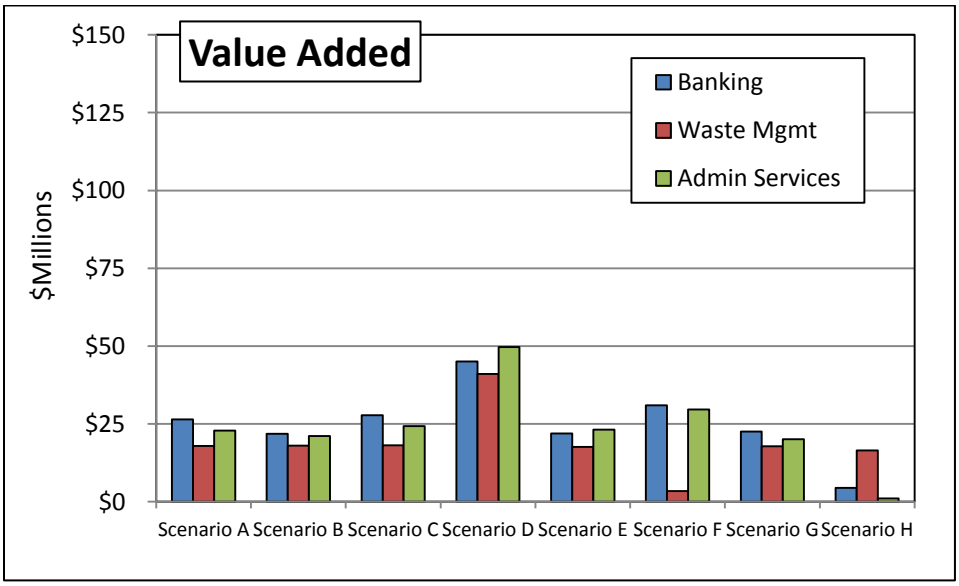
The three sectors showing the next highest levels of overall impact in outputs and value added are wholesale trade, professional services and health care.





The next three sectors with significant impacts are banking, waste management and administrative services.

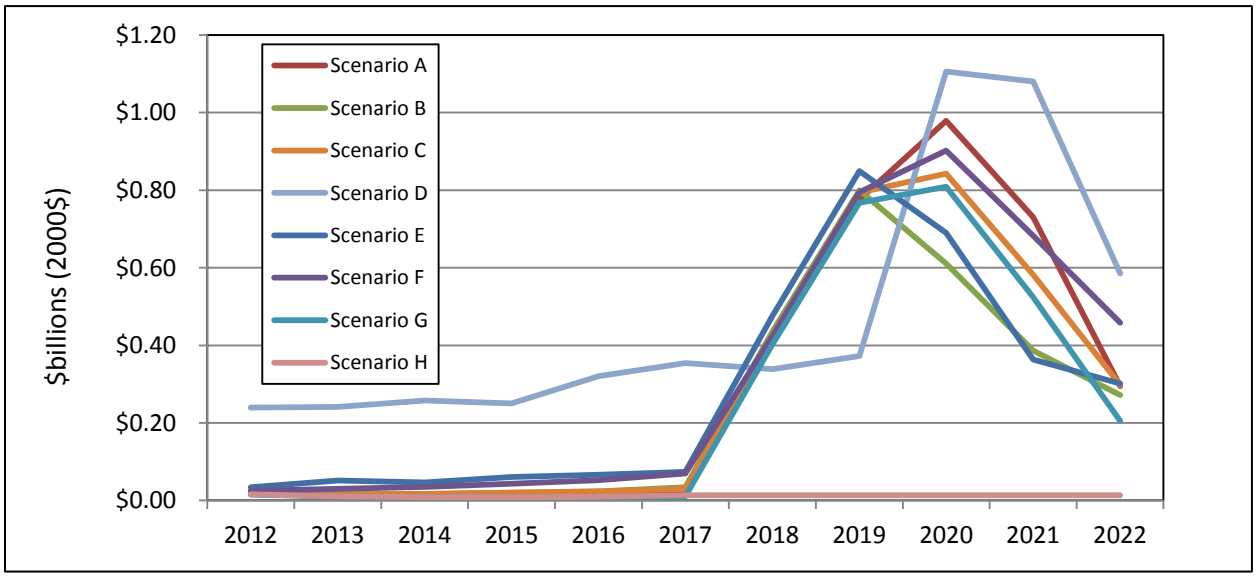




Employment, Income and Demand

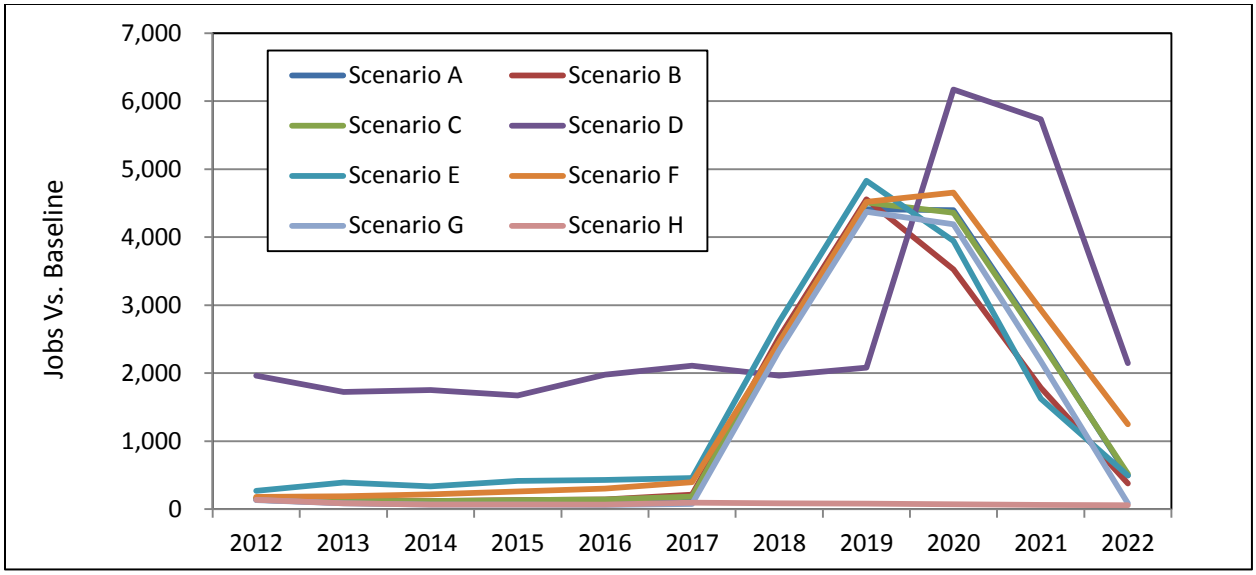
Below are year-by-year impacts to important macroeconomic impacts not captured as sectors. These include overall demand impacts, overall employment impacts, and overall personal income impacts.

*Changes in **Demand** under Eight LCFS Compliance Scenarios*



Aggregate demand is the total demand for final goods and services (as opposed to wholesale goods or raw materials) in an economy. Demand tracks very similarly to GSP for the eight LCFS scenarios considered in this study. As with other indicators, the onset of significant capital investment drives the largest portion of the changes from baseline in each scenario.

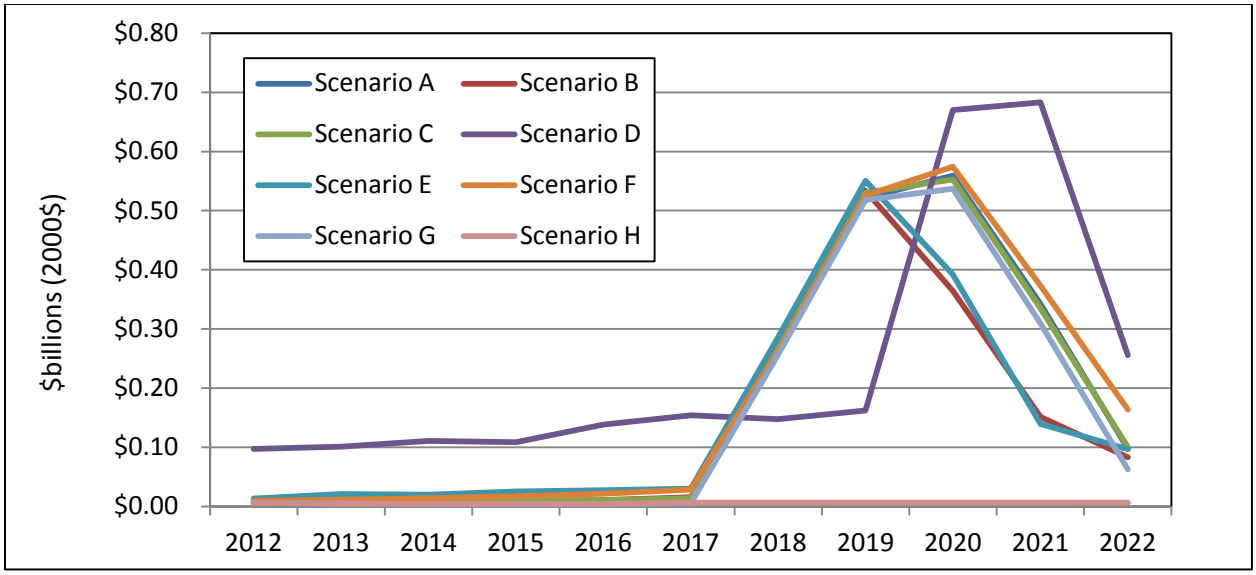
*Changes in **Employment** under Eight LCFS Compliance Scenarios*



Employment in the above graphic is measured as jobs. The scenarios reflect a correlation between the intensity of investment, which tracks with the timing of refinery construction, and increases in employment. Plants, once built, directly employ relatively small numbers of people (below 100 per plant). During the construction phase, by contrast, the spending involved works through the economy to create employment for thousands of people.

Scenarios D and H stand out much in the way they do in the GSP projections. In scenario D, the investment in fueling capacity and charger station installation drives employment even in the earlier years. This scenario results in approximately 2,000 additional jobs every year throughout the ten-year period even without the construction of any biofuels refining capacity. This employment is tied to other infrastructure creation. Scenario H again has no significant impact.

*Changes in **Income** under Eight LCFS Compliance Scenarios*



Income levels again follow a familiar pattern. Additional employment drives income changes at equivalent points in time across the 2012-2022 timeframe. The six scenarios assuming in-state biofuels production separate in 2020, however. Some see high income effects in 2020 while others see a much lower level than 2019 impacts. This is the result of different assumptions about the number and timing of biofuels plant production. Those scenarios which envision construction in 2020 at high levels see high income impacts. Others, which envision construction tailing off by that point, see income impacts fall. Scenarios D and H follow familiar outlying patterns.

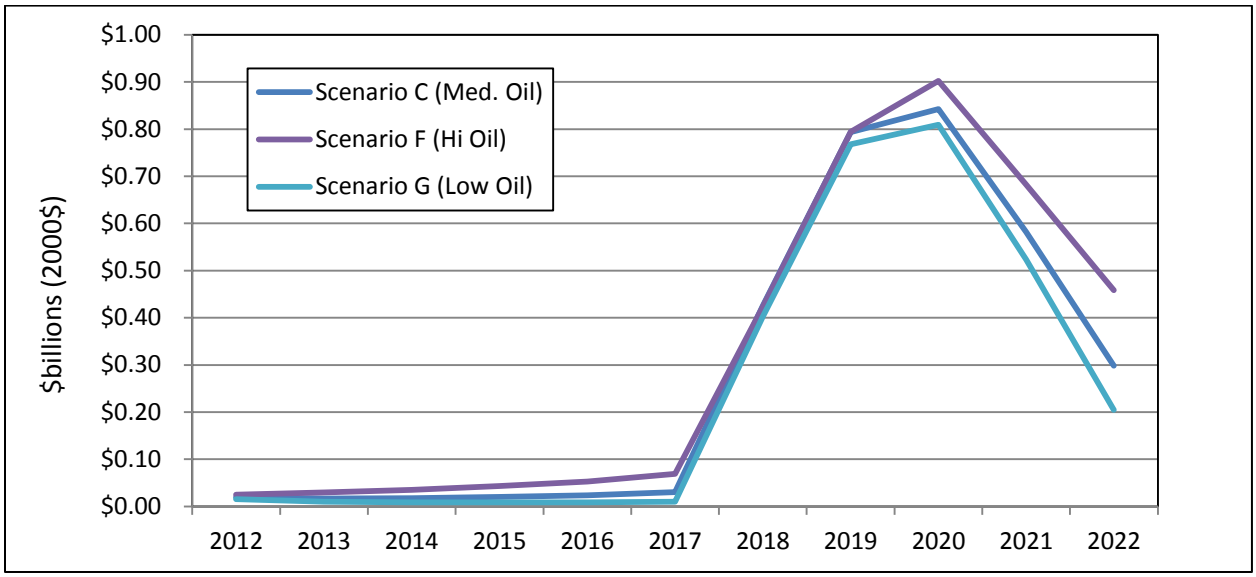
Special Scenario Pairings

Fuel Price

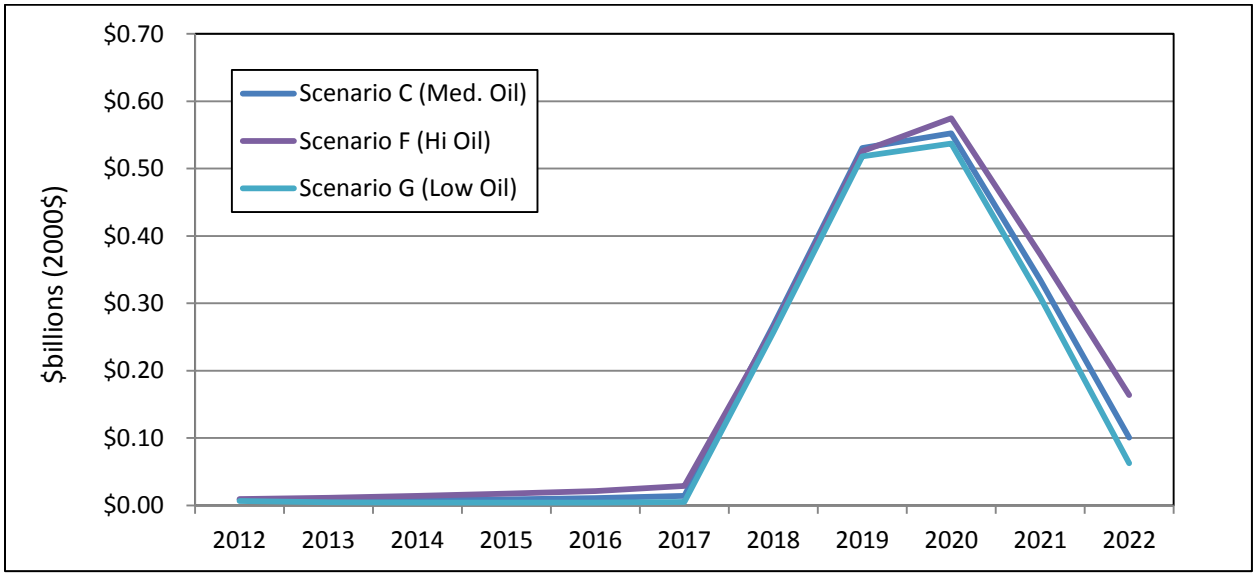
One scenario was modeled under three different fuel price projections. The standard projection used for all scenarios is drawn from the Department of Energy's Annual Energy Outlook, published in 2010. This "reference case" projection anticipates petroleum fuels (gasoline and diesel) growing gradually but constantly throughout the 2012-2022 period of analysis, reaching a retail price inclusive of all taxes of approximately $3.50 per gallon in 2022. Biodiesel and ethanol prices are projected to remain roughly at parity with gas and diesel prices. The high-price scenario involves petroleum fuels rising rapidly in price to over $5 per gallon by 2022. Further, the prices of gasoline and diesel outpace the prices of ethanol and biodiesel, making the shift to biofuels a cost-saving adjustment. The low-price scenario projects the same fuels to cost

approximately $2 per gallon throughout the period of analysis. These prices fall below the prices for biodiesel and ethanol in this projection, making the shift to biofuels represent an increase in costs. The graphs below show the sensitivity of the analysis to different fuel price assumptions:

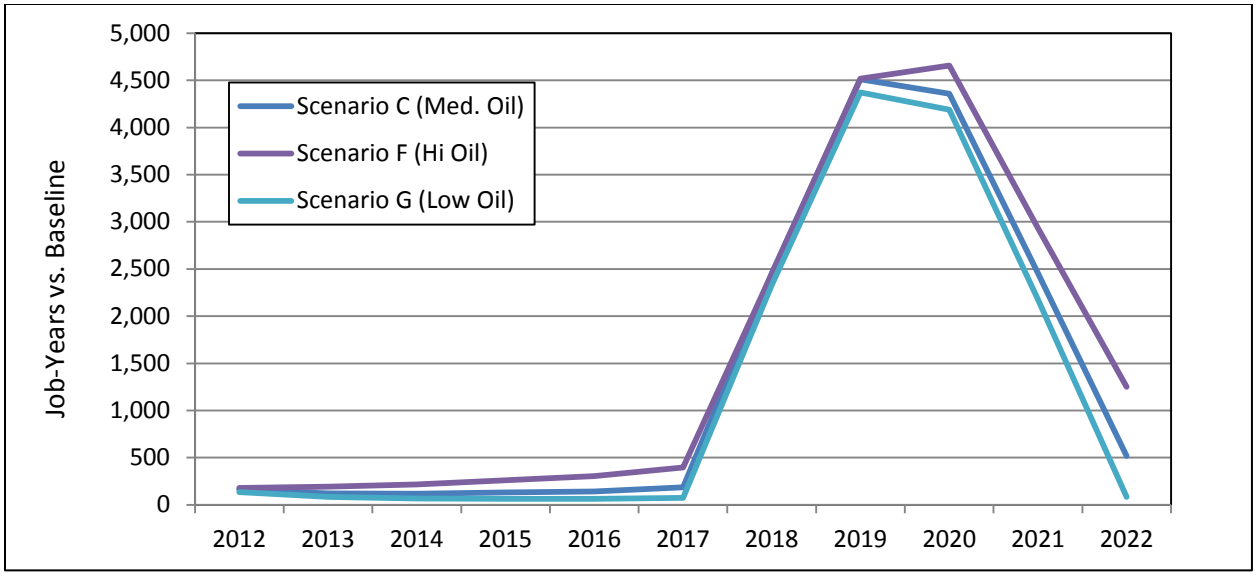
*Changes in **Demand** under Three Different Oil Price Projections*



*Changes in **Income** under Three Different Oil Price Projections*



*Changes in **Employment** Under Three Different Oil Price Projections*



These three graphics demonstrate that even very large changes in the projected price of oil will not have a dramatic change in the effect of a biofuels-based strategy. This may seem counter-intuitive, but it demonstrates the primary importance not of the fuel spending but instead of the investment in construction of refining capacity. The spikes in effects in all three graphs follow construction timing.

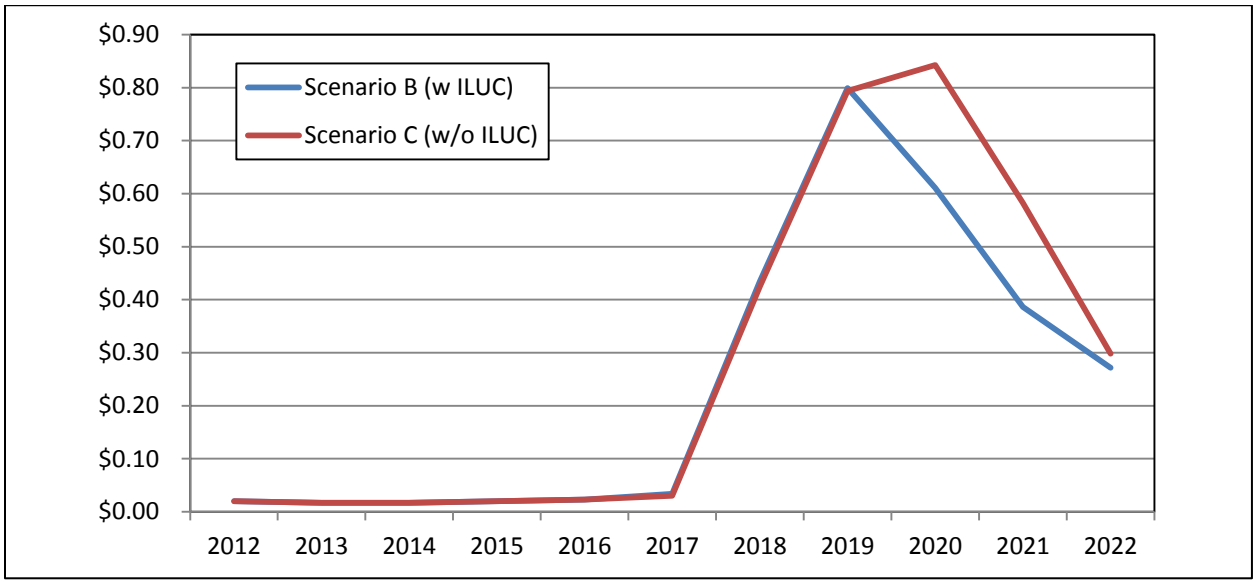
That said, the numbers for the year 2022 are deserving of attention. The line depicting Scenario F (the high-oil-price scenario) shows a significant difference from Scenarios C and G in the year 2022, the last year of the scenarios. By this time, the change in the fuel supply is significant, and consumers encounter significant savings by using biofuels in higher levels. As a consequence, significant consumer spending that would have gone to fuel is freed up for other spending, which drives demand and employment.

Indirect Land-Use Change

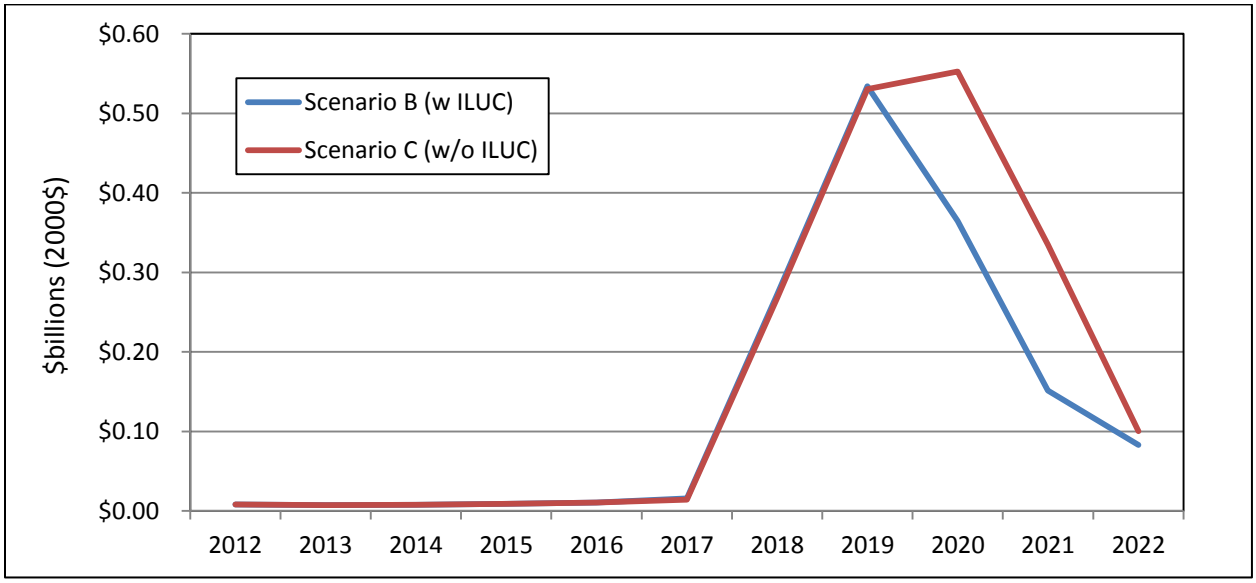
The publication of environmental research in *Science* and other publications have indicated that the greenhouse gas emissions from indirect land use changes from U.S. biofuels production may exceed those resulting from direct land use change. The conversion of cropland from food to fuel production can increase food prices and drive land use change in other areas of the globe to compensate for lost food and feed supply. Moreover, the U.S. Energy Independence and Security Act was recently amended to require the inclusion of indirect land-use change in life-cycle analyses of greenhouse gas emissions associated with U.S. biofuel production. In the economic analysis of the Oregon LCFS the question was asked if including adjustments for indirect land-

use change would impact the results. The graphs below indicate that there is some impact on employment, income and state product from the treatment of indirect land-use change, but that it is small relative to the impact of other variables. Therefore, the decision to include or exclude indirect land-use change should be made on grounds other than macroeconomic criteria.

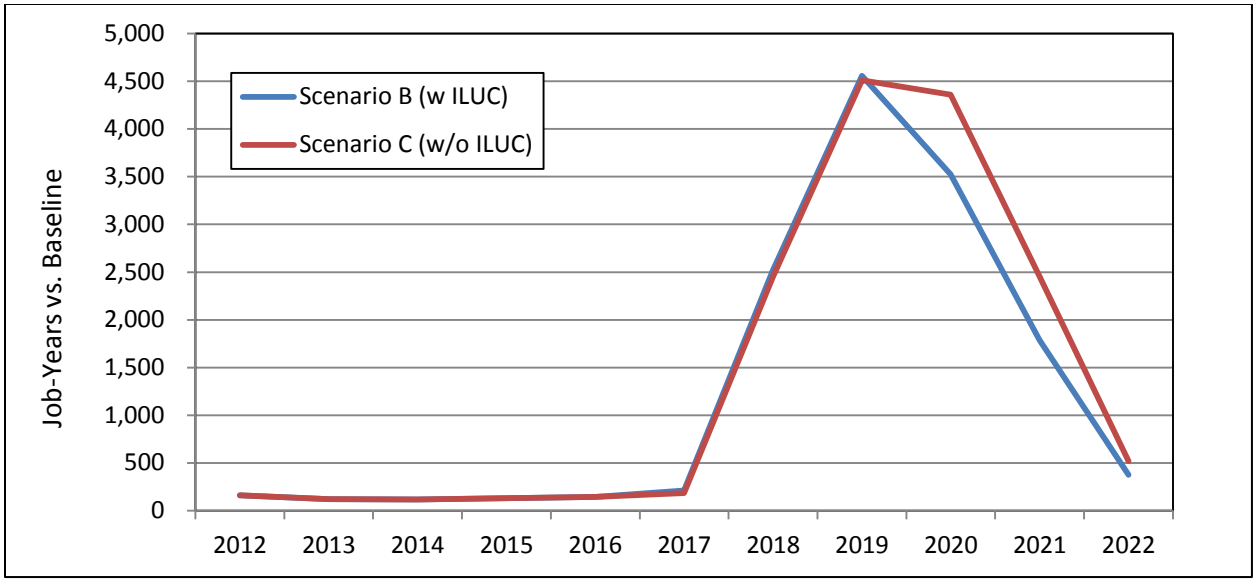
Impact of ILUC Consideration on ***Demand***



Impact of ILUC Consideration on ***Income***



Impact of ILUC Consideration on ***Employment***



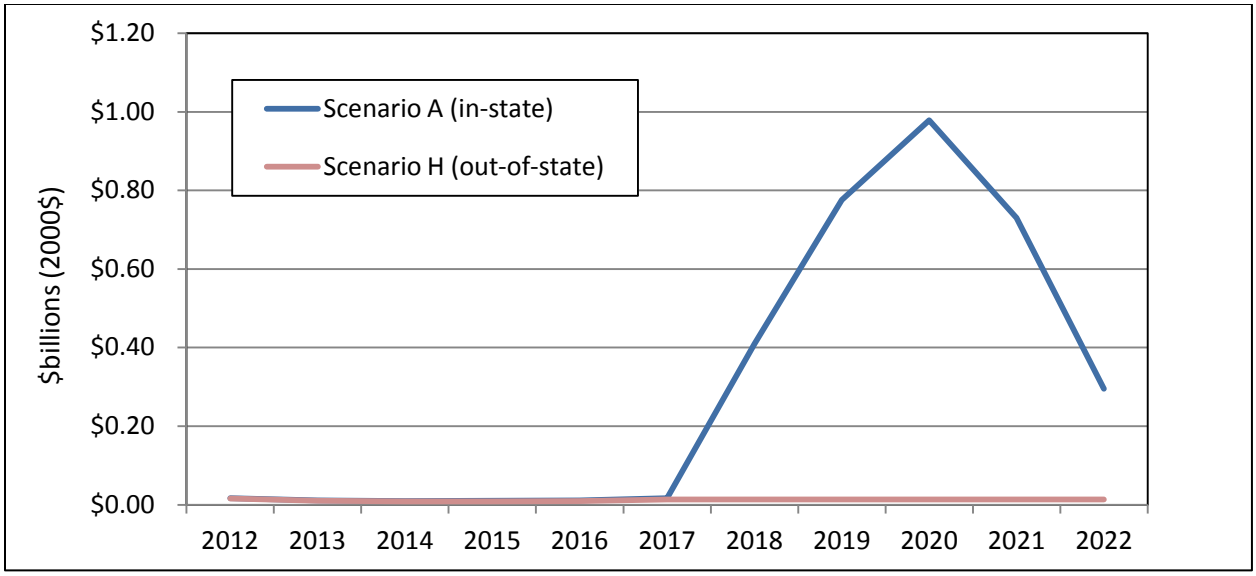
Considering ILUC as a factor in the carbon intensity of biofuels production adds a penalty to the carbon intensity of some fuels. Because production of biofuels from crops is now effectively less beneficial as a carbon-reduction technique, more reliance is placed on cellulosic and other fuels from waste or crops with a smaller indirect land use change penalty than corn or soybeans.

Origin of Biofuels

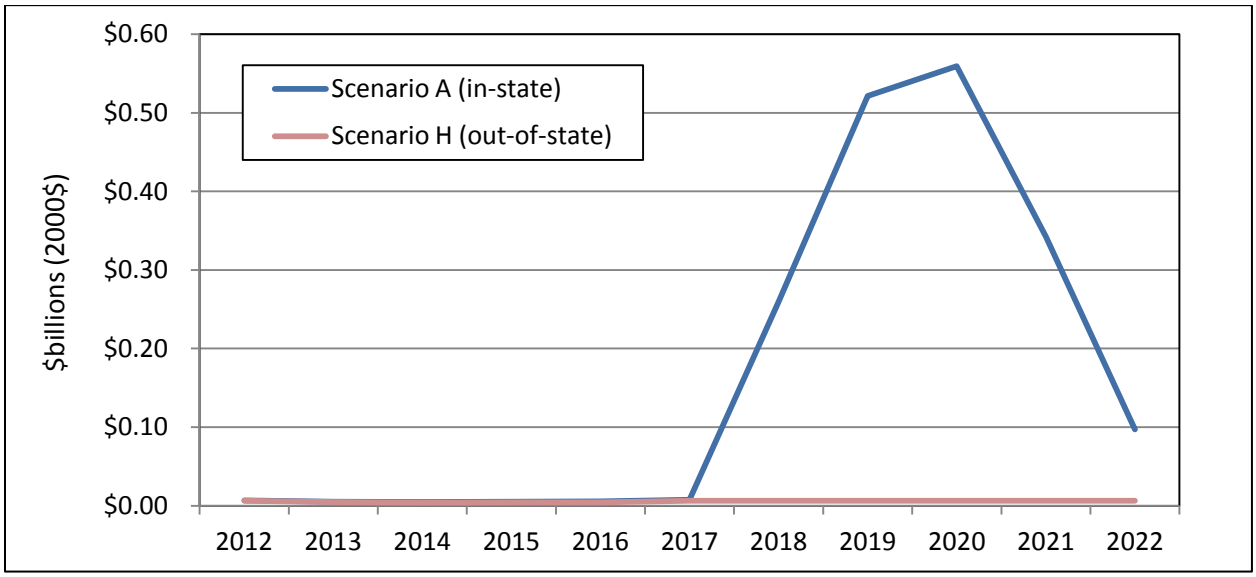
As indicated elsewhere in this report, there is an opportunity for economic gain if domestically produced fuel can replace some imported petroleum fuel. The Oregon LCFS is a technology forcing regulation that would result in less imported petroleum to Oregon and therefore a potential benefit. From the perspective of the Oregon economy, producing low carbon fuels in Oregon and replacing high carbon imported petroleum fuel will both reduce greenhouse gas emissions and provide an economic stimulus.

To test the impacts of fuel imports on the Oregon economy, a scenario was derived that compared a portion of the fuel supply produced in Oregon with a scenario where all additional capacity to produce biofuels would be out of state, and the fuel produced would be imported. The BAU includes current volumes of Oregon biofuels production.

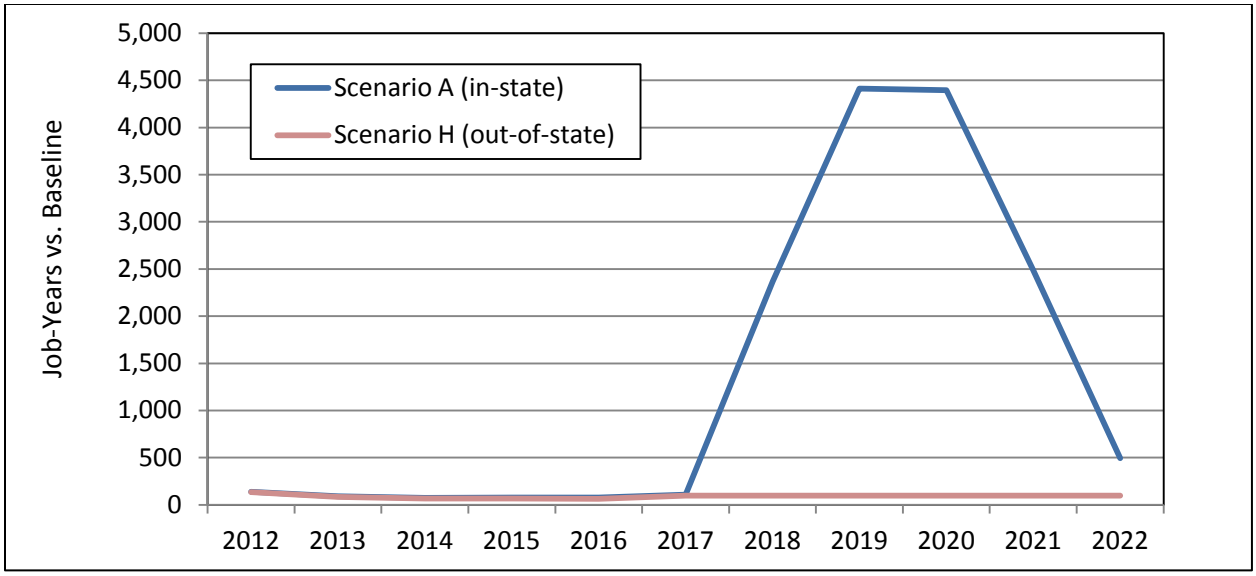
Impact of In-State vs. Out-of-State Biofuels Supply on ***Demand***



Impact of In-State vs. Out-of-State Biofuels Supply on ***Income***



Impact of In-State vs. Out-of-State Biofuels Supply on ***Employment***



As discussed above, the consumption of biofuels from out-of-state sources would not bring investment into the state of Oregon in the way that the development of an in-state biofuels industry would. Opportunities for spending on new capital and new infrastructure in-state, as well as the increased demand for agricultural products and services, are lost by reliance on out-of-state fuel supplies. In this way, the costs of importing biofuels are similar in nature to the costs of importing petroleum products.

Scenario H impacts are not negative, even though they involve reliance on imports. This is due to the fact that the baseline scenario assumes that almost all fuel consumed by the transportation sector is already imported. This scenario would produce economic losses only if it were to drive even more imports than the baseline scenario.

Conclusion

This study has produced a number of projections regarding the broader economic impacts of a low-carbon fuel standard under a variety of scenarios meant to bracket the range of likely industry responses to such a regulation. Consistencies occur among the results of the various scenarios which indicate economic impacts that appear repeatedly even as assumptions are changed. The first is that regardless of the exact fuel mix, an LCFS which encourages a temporary inflow of investment from out of state will likely spur economic growth and job creation. This inflow of capital for the construction of new infrastructure produces a temporary increase in economic activity during the construction phase. The only scenario not requiring in-

state production, Scenario H, is also the only scenario not to produce significant economic benefits.

The scenario analyses provide much less guidance about the likely long-term impact of an LCFS after the necessary new infrastructure is in place. The scenarios reach their end in 2022, which is just at the end of the infrastructure expansion. The scenario analyses suggest that the economic impacts without spending on infrastructure are small in comparison to those in the years of capital expansion, but the period of analysis ends before any post-construction trend is established. The expectation, however, is that displacing imports with domestically-produced fuels would result in net economic benefit to the state as it captures the employment, profits and producer surpluses currently gained out of state.

The analysis of Scenario D, while again not being a prediction of the future, does expose certain economic advantages of natural gas and electricity as transportation fuels. The presence of effective distribution systems for both (natural gas pipelines and the power grid are widespread) limits the need for expensive new refining plants for these fuels. Distributed infrastructure in the form of charging or fueling stations can be built without delay, producing earlier and higher economic impacts.

Also, projected prices for electricity and natural gas are both significantly below the prices of conventional fuels or biofuels. The macroeconomic modeling immediately demonstrates a large positive impact from reducing the costs of fuel, even when taking into account the significant additional vehicle cost. Consumers direct the savings to other expenditures or to savings, and sectors far and wide see growth as a result.

It bears repeating that these are analyses of scenarios imagined as industry responses, and are not predictions of the future. These analyses are very sensitive to fuel price assumptions, cost assumptions, and projections about the economy in general – all of which are highly unreliable. The future courses of technology as well as policy will also be highly influential, whether changes occur locally or nationally.

Appendix A: VISION Results

Fuel Expenditure Values – Scenario A

Fuels Consumption Change vs BAU

	Gasoline (2008 $bil) (out-of-state)	Diesel (2008 $bil)	CNG (2008 $bil)	Electricity (2008 $bil)	Ethanol (2008 $bil) (in-state)	Hydrogen (2008 $bil)	F-T Diesel (2008 $bil)	Bio-Diesel (2008 $bil)
2010	-$0.0001	-$0.0004	-$0.0017		$0.0000			$0.0000
2011	-$0.0002	-$0.0010	-$0.0034		$0.0000			$0.0000
2012	-$0.0003	-$0.0018	-$0.0053		$0.0000			$0.0000
2013	-$0.0006	-$0.0026	-$0.0070		$0.0000			$0.0000
2014	-$0.0008	-$0.0033	-$0.0088		-$0.0001			$0.0000
2015	-$0.0010	-$0.0040	-$0.0108		-$0.0001			$0.0000
2016	-$0.0012	-$0.0047	-$0.0129		-$0.0001			$0.0000
2017	-$0.0014	-$0.0055	-$0.0148		-$0.0001			$0.0000
2018	-$0.0016	-$0.0061	-$0.0166		-$0.0002			-$0.0001
2019	-$0.0018	-$0.0067	-$0.0183		-$0.0002			-$0.0002
2020	-$0.0020	-$0.0071	-$0.0200		-$0.0002			-$0.0003
2021	-$0.0374	-$0.0075	-$0.0212		$0.0360			-$0.0004
2022	-$0.1419	-$0.0444	-$0.0222		$0.1416			$0.0457

Fuel Expenditure Values – Scenario B

Fuels Consumption Change vs BAU

	Gasoline (2008 $bil)	Diesel (2008 $bil)	CNG (2008 $bil)	Electricity (2008 $bil)	Ethanol (2008 $bil)	Hydrogen (2008 $bil)	F-T Diesel (2008 $bil)	Bio-Diesel (2008 $bil)

2010	-$0.0001	-$0.0004	-$0.0017	$0.0000	$0.000
2011	-$0.0002	-$0.0010	-$0.0034	$0.0000	$0.000
2012	-$0.0003	-$0.0018	-$0.0053	$0.0000	$0.000
2013	-$0.0006	-$0.0026	-$0.0070	$0.0000	$0.000
2014	-$0.0008	-$0.0033	-$0.0088	-$0.0001	$0.000
2015	-$0.0010	-$0.0040	-$0.0108	-$0.0001	$0.000
2016	-$0.0012	-$0.0047	-$0.0129	-$0.0001	$0.000
2017	-$0.0012	-$0.0055	-$0.0148	-$0.0001	$0.000
2018	-$0.0012	-$0.0061	-$0.0167	-$0.0002	$0.000
2019	-$0.1315	-$0.0067	-$0.0183	$0.1379	$0.000
2020	-$0.3492	-$0.0071	-$0.0200	$0.3772	$0.000
2021	-$0.3908	-$0.0075	-$0.0212	$0.3998	$0.000
2022	-$0.3752	-$0.0160	-$0.0223	$0.3789	$0.010

Fuel Expenditure Values – Scenario C

Fuels Consumption Change vs BAU

	Gasoline *(2008 $bil)*	**Diesel** *(2008 $bil)*	**CNG** *(2008 $bil)*	**Electricity** *(2008 $bil)*	**Ethanol** *(2008 $bil)*	**Hydrogen** *(2008 $bil)*	**F-T Diesel** *(2008 $bil)*	**Bio-Diesel** *(2008 $bil)*
2010	-$0.0001	-$0.0004	-$0.0017		$0.0000			$0.0000
2011	-$0.0002	-$0.0010	-$0.0034		$0.0000			$0.0000
2012	-$0.0003	-$0.0018	-$0.0053		$0.0000			$0.0000
2013	-$0.0006	-$0.0026	-$0.0070		$0.0000			$0.0000
2014	-$0.0008	-$0.0033	-$0.0088		-$0.0001			$0.0000
2015	-$0.0010	-$0.0040	-$0.0108		-$0.0001			$0.0000
2016	-$0.0012	-$0.0047	-$0.0129		-$0.0001			$0.0000
2017	-$0.0012	-$0.0055	-$0.0148		-$0.0001			$0.0000
2018	-$0.0012	-$0.0061	-$0.0167		-$0.0002			-$0.0001
2019	-$0.0011	-$0.0067	-$0.0183		-$0.0002			-$0.0002
2020	$0.0002	-$0.0071	-$0.0200		-$0.0002			-$0.0003
2021	-$0.0769	-$0.0075	-$0.0212		$0.0774			-$0.0004
2022	-$0.1993	-$0.0078	-$0.0223		$0.2002			-$0.0006

Fuel Expenditure Values – Scenario D

Fuels Consumption Change vs BAU								
	Gasoline	**Diesel**	**CNG**	**Electricity**	**Ethanol**	**Hydrogen**	**F-T Diesel**	**Bio-Diesel**
	(2008 $bil)	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*
2010	-$0.0001	-$0.0063	$0.0017	$0.0000	$0.0000			-$0.0002
2011	-$0.0002	-$0.0144	$0.0052	$0.0000	$0.0000			-$0.0004
2012	-$0.0070	-$0.0258	$0.0095	$0.0013	-$0.0005			-$0.0008
2013	-$0.0167	-$0.0374	$0.0136	$0.0029	-$0.0012			-$0.0013
2014	-$0.0293	-$0.0487	$0.0180	$0.0051	-$0.0022			-$0.0018
2015	-$0.0565	-$0.0587	$0.0227	$0.0102	-$0.0044			-$0.0025
2016	-$0.0776	-$0.0676	$0.0276	$0.0144	-$0.0067			-$0.0033
2017	-$0.1019	-$0.0791	$0.0322	$0.0190	-$0.0094			-$0.0043
2018	-$0.1242	-$0.0888	$0.0367	$0.0230	-$0.0123			-$0.0056
2019	-$0.1475	-$0.0967	$0.0407	$0.0271	-$0.0159			-$0.0068
2020	-$0.1725	-$0.1033	$0.0447	$0.0316	-$0.0196			-$0.0081
2021	-$0.2041	-$0.1096	$0.0474	$0.0362	-$0.0150			-$0.0099
2022	-$0.3296	-$0.1151	$0.0498	$0.0414	$0.0787			-$0.0117

Fuel Expenditure Values – Scenario E

Fuels Consumption Change vs BAU								
	Gasoline	**Diesel**	**CNG**	**Electricity**	**Ethanol**	**Hydrogen**	**F-T Diesel**	**Bio-Diesel**
	(2008 $bil)	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*	*(2008 $bil)*
2010	-$0.0009	$0.0003	$0.0002	$0.0000	-$0.0001			$0.0000
2011	-$0.0022	$0.0008	$0.0006	$0.0000	-$0.0002			$0.0000
2012	-$0.0052	$0.0014	$0.0011	$0.0003	-$0.0004			-$0.0001
2013	-$0.0091	$0.0021	$0.0015	$0.0006	-$0.0007			-$0.0001
2014	-$0.0137	$0.0031	$0.0019	$0.0010	-$0.0010			-$0.0002

2015	-$0.0214	$0.0044	$0.0024	$0.0020	-$0.0017		-$0.0004
2016	-$0.0281	$0.0060	$0.0029	$0.0029	-$0.0025		-$0.0006
2017	-$0.0357	$0.0082	$0.0034	$0.0038	-$0.0033		-$0.0009
2018	-$0.0433	$0.0107	$0.0039	$0.0046	-$0.0038		-$0.0012
2019	-$0.0518	$0.0137	$0.0043	$0.0053	-$0.0045		-$0.0015
2020	-$0.0611	$0.0171	$0.0047	$0.0062	-$0.0051		-$0.0020
2021	-$0.0706	$0.0127	$0.0049	$0.0071	-$0.0054		$0.0083
2022	-$0.2151	-$0.0024	$0.0052	$0.0080	$0.1299		$0.0325

Fuel Expenditure Values – Scenario F

Fuels Consumption Change vs BAU								
	Gasoline *(2008 $bil)*	**Diesel** *(2008 $bil)*	**CNG** *(2008 $bil)*	**Electricity** *(2008 $bil)*	**Ethanol** *(2008 $bil)*	**Hydrogen** *(2008 $bil)*	**F-T Diesel** *(2008 $bil)*	**Bio-Diesel** *(2008 $bil)*
2010	-$0.0001	-$0.0004	-$0.0017	$0.0000	$0.0000			$0.0000
2011	-$0.0002	-$0.0010	-$0.0034	$0.0000	$0.0000			$0.0000
2012	-$0.0004	-$0.0020	-$0.0053	$0.0000	$0.0000			-$0.0001
2013	-$0.0007	-$0.0030	-$0.0070	$0.0000	$0.0000			-$0.0001
2014	-$0.0010	-$0.0041	-$0.0088	$0.0000	-$0.0001			-$0.0001
2015	-$0.0013	-$0.0053	-$0.0108	$0.0000	-$0.0001			-$0.0002
2016	-$0.0016	-$0.0065	-$0.0129	$0.0000	-$0.0001			-$0.0002
2017	-$0.0067	-$0.0077	-$0.0148	$0.0000	-$0.0004			-$0.0003
2018	-$0.0072	-$0.0088	-$0.0167	$0.0000	-$0.0005			-$0.0004
2019	-$0.0074	-$0.0098	-$0.0183	$0.0000	-$0.0005			-$0.0004
2020	-$0.0138	-$0.0107	-$0.0200	$0.0000	-$0.0010			-$0.0005
2021	-$0.1236	-$0.0114	-$0.0212	$0.0000	$0.0658			-$0.0006
2022	-$0.2972	-$0.0122	-$0.0223	$0.0000	$0.1717			-$0.0004

Fuel Expenditure Values – Scenario G

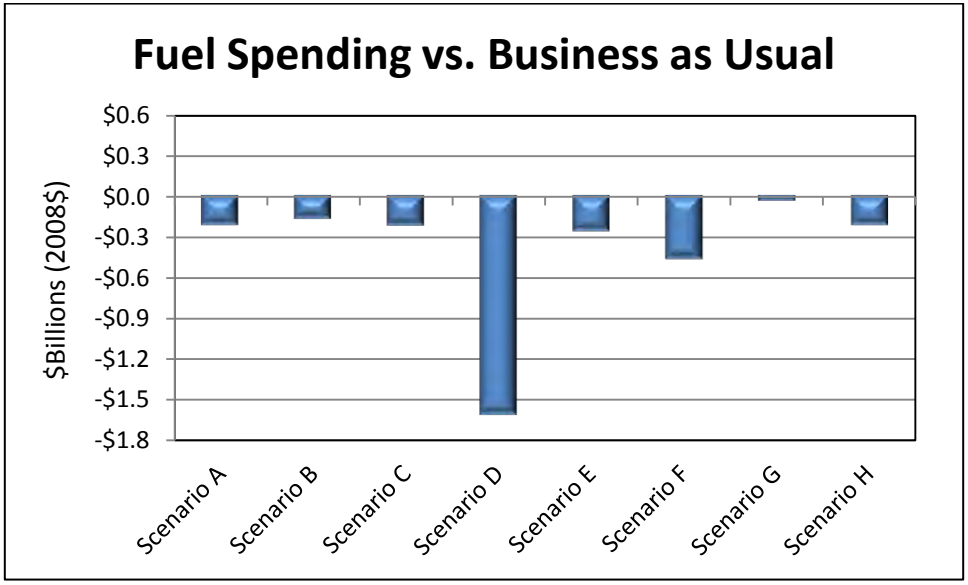
Fuels Consumption Change vs BAU	Gasoline (2008 $bil)	Diesel (2008 $bil)	CNG (2008 $bil)	Electricity (2008 $bil)	Ethanol (2008 $bil)	Hydrogen (2008 $bil)	F-T Diesel (2008 $bil)	Bio-Diesel (2008 $bil)
2010	-$0.0001	-$0.0004	-$0.0017	$0.0000	$0.0000			$0.0000
2011	-$0.0002	-$0.0009	-$0.0034	$0.0000	$0.0000			$0.0000
2012	-$0.0003	-$0.0014	-$0.0053	$0.0000	$0.0000			-$0.0001
2013	-$0.0004	-$0.0018	-$0.0070	$0.0000	$0.0000			-$0.0001
2014	-$0.0005	-$0.0023	-$0.0088	$0.0000	-$0.0001			-$0.0001
2015	-$0.0007	-$0.0027	-$0.0108	$0.0000	-$0.0001			-$0.0002
2016	-$0.0008	-$0.0031	-$0.0129	$0.0000	-$0.0001			-$0.0002
2017	$0.0034	-$0.0035	-$0.0148	$0.0000	$0.0005			-$0.0003
2018	$0.0035	-$0.0038	-$0.0166	$0.0000	$0.0005			-$0.0004
2019	$0.0037	-$0.0039	-$0.0183	$0.0000	$0.0005			-$0.0005
2020	$0.0106	-$0.0042	-$0.0200	$0.0000	$0.0018			-$0.0005
2021	-$0.0428	-$0.0043	-$0.0212	$0.0000	$0.0867			-$0.0008
2022	-$0.1297	-$0.0043	-$0.0222	$0.0000	$0.2191			-$0.0013

Fuel Expenditure Values – Scenario H

Fuels Consumption Change vs BAU	Gasoline (2008 $bil) (out-of-state)	Diesel (2008 $bil)	CNG (2008 $bil)	Electricity (2008 $bil)	Ethanol (2008 $bil) (in-state)	Hydrogen (2008 $bil)	F-T Diesel (2008 $bil)	Bio-Diesel (2008 $bil)
2010	-$0.0001	-$0.0004	-$0.0017	$0.0000	$0.0000			$0.0000
2011	-$0.0002	-$0.0010	-$0.0034	$0.0000	$0.0000			$0.0000
2012	-$0.0003	-$0.0018	-$0.0053	$0.0000	$0.0000			$0.0000
2013	-$0.0006	-$0.0026	-$0.0070	$0.0000	$0.0000			$0.0000
2014	-$0.0008	-$0.0033	-$0.0088	$0.0000	-$0.0001			$0.0000
2015	-$0.0010	-$0.0040	-$0.0108	$0.0000	-$0.0001			$0.0000

2016	-$0.0012	-$0.0047	-$0.0129	$0.0000	-$0.0001	$0.0000
2017	-$0.0014	-$0.0055	-$0.0148	$0.0000	-$0.0001	$0.0000
2018	-$0.0016	-$0.0061	-$0.0166	$0.0000	-$0.0002	-$0.0001
2019	-$0.0018	-$0.0067	-$0.0183	$0.0000	-$0.0002	-$0.0002
2020	-$0.0020	-$0.0071	-$0.0200	$0.0000	-$0.0002	-$0.0003
2021	-$0.0387	-$0.0075	-$0.0212	$0.0000	$0.0373	-$0.0004
2022	-$0.1430	-$0.0444	-$0.0222	$0.0000	$0.1427	$0.0457

Total Net Changes in Fuel Spending vs. Business-as-Usual Scenario:



Vehicle Expenditures – Scenario D

Gasoline		EV	
Auto	LT	Auto	LT

Veh Unit Price		Consumer Spending Change (mil 2008$)	Veh Unit Price		Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)
$25,810		**$0.000**	$25,382		**$0.000**	$42,103	1.6313	**$0.000**	$46,458	1.8	**$0.000**
$25,810		**$0.000**	$25,382		**$0.000**	$42,014	1.62785	**$0.000**	$46,430	1.798919	**$0.000**
$25,810		**-$42.328**	$25,382		**-$66.702**	$41,925	1.6244	**$9.822**	$46,402	1.797838	**$17.420**
$25,810		**-$68.870**	$25,382		**-$76.096**	$41,836	1.62095	**$15.948**	$46,374	1.796757	**$19.862**
$25,810		**-$111.927**	$25,382		**-$83.516**	$41,747	1.6175	**$25.863**	$46,346	1.795676	**$21.785**
$25,810		**-$363.432**	$25,382		**-$88.973**	$41,658	1.61405	**$83.800**	$46,318	1.794595	**$23.195**
$25,810		**-$319.309**	$25,382		**-$65.526**	$41,569	1.6106	**$73.469**	$46,290	1.793514	**$17.072**
$25,810		**-$364.436**	$25,382		**-$74.689**	$41,480	1.60715	**$83.672**	$46,262	1.792433	**$19.448**
$25,810		**-$405.338**	$25,382		**-$81.011**	$41,391	1.6037	**$21.296**	$46,234	1.791352	**$4.834**
$25,810		**-$435.901**	$25,382		**-$65.833**	$41,302	1.60025	**$22.445**	$46,206	1.790271	**$3.856**
$25,810		**-$473.583**	$25,382		**-$61.284**	$41,213	1.5968	**$29.104**	$46,179	1.78919	**$4.291**
$25,810		**-$498.670**	$25,382		**-$60.339**	$41,190	1.5959	**$34.164**	$46,151	1.788121	**$4.710**
$25,810		**-$539.453**	$25,382		**-$102.587**	$41,167	1.595	**$50.731**	$46,123	1.787052	**$10.992**

PHEV						CNG					
Auto			LT			Auto			LT		
Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Price	Price Factor	Consumer Spending Change (mil 2008$)
$35,617	1.38	**$0.000**	$39,128	1.516	**$0.000**	$35,488	1.375	**$0.000**	$34,456	1.335	**$0.000**
$35,411	1.372	**$0.000**	$38,957	1.5094	**$0.000**	$35,475	1.3745	**$0.000**	$34,443	1.3345	**$0.000**
$35,204	1.364	**$49.487**	$38,787	1.5028	**$87.369**	$35,463	1.374	**$0.000**	$34,430	1.334	**$0.000**
$34,998	1.356	**$80.047**	$38,617	1.4962	**$99.236**	$35,450	1.3735	**$0.000**	$34,417	1.3335	**$0.000**
$34,792	1.348	**$129.324**	$38,446	1.4896	**$108.432**	$35,437	1.373	**$0.000**	$34,404	1.333	**$0.000**
$34,585	1.34	**$417.427**	$38,276	1.483	**$115.005**	$35,424	1.3725	**$0.000**	$34,391	1.3325	**$0.000**
$34,379	1.332	**$364.560**	$38,105	1.4764	**$84.322**	$35,411	1.372	**$0.000**	$34,379	1.332	**$0.000**
$34,172	1.324	**$413.583**	$37,935	1.4698	**$95.683**	$35,398	1.3715	**$0.000**	$34,366	1.3315	**$0.000**
$33,966	1.316	**$515.950**	$37,765	1.4632	**$116.585**	$35,385	1.371	**$0.000**	$34,353	1.331	**$0.000**
$33,759	1.308	**$551.813**	$37,594	1.4566	**$94.372**	$35,372	1.3705	**$0.000**	$34,340	1.3305	**$0.000**
$33,553	1.3	**$591.964**	$37,424	1.45	**$86.884**	$35,359	1.37	**$0.000**	$34,327	1.33	**$0.000**
$33,475	1.297	**$619.009**	$37,243	1.443	**$84.737**	$35,334	1.369	**$0.000**	$34,314	1.3295	**$0.000**
$33,398	1.294	**$656.894**	$37,063	1.436	**$140.968**	$35,308	1.368	**$0.000**	$34,301	1.329	**$0.000**

Vehicle Expenditures – Scenario E

Gasoline						EV					
Auto			LT			Auto			LT		
Veh Unit Price		Consumer Spending Change (mil 2008$)	Veh Unit Price		Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)

2010	$25,810	**$0.000**	$25,382	**$0.000**	$42,103	1.6313	**$0.000**	$46,458	1.8	**$0.000**
2011	$25,810	**$0.000**	$25,382	**$0.000**	$42,014	1.62785	**$0.000**	$46,430	1.798919	**$0.000**
2012	$25,810	**-$42.328**	$25,382	**-$66.702**	$41,925	1.6244	**$9.822**	$46,402	1.797838	**$17.420**
2013	$25,810	**-$68.870**	$25,382	**-$76.096**	$41,836	1.62095	**$15.948**	$46,374	1.796757	**$19.862**
2014	$25,810	**-$111.927**	$25,382	**-$83.516**	$41,747	1.6175	**$25.863**	$46,346	1.795676	**$21.785**
2015	$25,810	**-$363.432**	$25,382	**-$88.973**	$41,658	1.61405	**$83.800**	$46,318	1.794595	**$23.195**
2016	$25,810	**-$319.309**	$25,382	**-$65.526**	$41,569	1.6106	**$73.469**	$46,290	1.793514	**$17.072**
2017	$25,810	**-$364.436**	$25,382	**-$74.689**	$41,480	1.60715	**$83.672**	$46,262	1.792433	**$19.448**
2018	$25,810	**-$405.338**	$25,382	**-$81.011**	$41,391	1.6037	**$21.296**	$46,234	1.791352	**$4.834**
2019	$25,810	**-$435.901**	$25,382	**-$65.833**	$41,302	1.60025	**$22.445**	$46,206	1.790271	**$3.856**
2020	$25,810	**-$473.583**	$25,382	**-$61.284**	$41,213	1.5968	**$29.104**	$46,179	1.78919	**$4.291**
2021	$25,810	**-$498.670**	$25,382	**-$60.339**	$41,190	1.5959	**$34.164**	$46,151	1.788121	**$4.710**
2022	$25,810	**-$539.453**	$25,382	**-$102.587**	$41,167	1.595	**$50.731**	$46,123	1.787052	**$10.992**

PHEV						**CNG**					
Auto			LT			Auto			LT		
Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Unit Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Price	Price Factor	Consumer Spending Change (mil 2008$)	Veh Price	Price Factor	Consumer Spending Change (mil 2008$)
$35,617	1.38	**$0.000**	$39,128	1.516	**$0.000**	$35,488	1.375	**$0.000**	$34,456	1.335	**$0.000**
$35,411	1.372	**$0.000**	$38,957	1.5094	**$0.000**	$35,475	1.3745	**$0.000**	$34,443	1.3345	**$0.000**
$35,204	1.364	**$49.487**	$38,787	1.5028	**$87.369**	$35,463	1.374	**$0.000**	$34,430	1.334	**$0.000**
$34,998	1.356	**$80.047**	$38,617	1.4962	**$99.236**	$35,450	1.3735	**$0.000**	$34,417	1.3335	**$0.000**
$34,792	1.348	**$129.324**	$38,446	1.4896	**$108.432**	$35,437	1.373	**$0.000**	$34,404	1.333	**$0.000**
$34,585	1.34	**$417.427**	$38,276	1.483	**$115.005**	$35,424	1.3725	**$0.000**	$34,391	1.3325	**$0.000**
$34,379	1.332	**$364.560**	$38,105	1.4764	**$84.322**	$35,411	1.372	**$0.000**	$34,379	1.332	**$0.000**
$34,172	1.324	**$413.583**	$37,935	1.4698	**$95.683**	$35,398	1.3715	**$0.000**	$34,366	1.3315	**$0.000**
$33,966	1.316	**$515.950**	$37,765	1.4632	**$116.585**	$35,385	1.371	**$0.000**	$34,353	1.331	**$0.000**
$33,759	1.308	**$551.813**	$37,594	1.4566	**$94.372**	$35,372	1.3705	**$0.000**	$34,340	1.3305	**$0.000**
$33,553	1.3	**$591.964**	$37,424	1.45	**$86.884**	$35,359	1.37	**$0.000**	$34,327	1.33	**$0.000**

$33,475	1.297	**$619.009**	$37,243	1.443	**$84.737**	$35,334	1.369	**$0.000**	$34,314	1.3295	**$0.000**
$33,398	1.294	**$656.894**	$37,063	1.436	**$140.968**	$35,308	1.368	**$0.000**	$34,301	1.329	**$0.000**

Charging Unit Costs for EVs and PHEVs – Scenario D

	Home Charger Purchase Expenditures by Year							
	annual expenditure on **Level-1** Chargers:	*(thousand 2008$)*			annual expenditure on **Level-2** Chargers:	*(thousand 2008$)*		
	Labor	**Materials**	**Permit**	Total	**Labor**	**Materials**	**Permit**	Total
2010	*(in-state)*	*(out-of-state)*	*(gov revenue)*		*(in-state)*	*(out-of-state)*	*(gov revenue)*	
2011								
2012	$411.83	$446.51	$15.17	$873.52	$3,540.71	$3,831.48	$51.53	$7,423.72
2013	$621.48	$673.82	$22.90	$1,318.20	$4,522.43	$4,893.82	$65.82	$9,482.07
2014	$949.85	$1,029.84	$34.99	$2,014.69	$5,816.41	$6,294.05	$84.65	$12,195.10
2015	$2,811.17	$3,047.90	$103.57	$5,962.65	$11,927.97	$12,907.50	$173.59	$25,009.06
2016	$2,450.94	$2,657.33	$90.30	$5,198.56	$9,996.99	$10,817.95	$145.49	$20,960.42
2017	$2,797.17	$3,032.72	$103.05	$5,932.95	$11,406.10	$12,342.77	$165.99	$23,914.87
2018	$3,507.23	$3,802.58	$129.21	$7,439.02	$11,653.76	$12,610.77	$169.60	$24,434.13
2019	$3,737.94	$4,052.72	$137.71	$7,928.37	$11,723.99	$12,686.77	$170.62	$24,581.38
2020	$4,017.39	$4,355.69	$148.01	$8,521.09	$12,414.18	$13,433.64	$180.66	$26,028.47
2021	$4,203.63	$4,557.62	$154.87	$8,916.13	$12,960.15	$14,024.45	$188.61	$27,173.21
2022	$4,532.64	$4,914.33	$166.99	$9,613.96	$15,613.91	$16,896.14	$227.23	$32,737.28

Public/Commercial Level 2 2-Charger Station Purchases by Year:			
Annual Expenditure on Level-2 Charger Stations::	***(Variation vs. BAU)***		
Labor	Materials	Trenching/Repair	Permits
(in-state)	*(out of state)*	*(in-state)*	*(gov revenue)*
$55,796	$81,731	$53,768	$182
$107,300	$157,175	$103,400	$350
$163,096	$238,906	$157,168	$532
$214,600	$314,350	$206,800	$700
$270,396	$396,081	$260,568	$882
$321,900	$471,525	$310,200	$1,050
$377,696	$553,256	$363,968	$1,232
$429,200	$628,700	$413,600	$1,400
$484,996	$710,431	$467,368	$1,582
$536,500	$785,875	$517,000	$1,750

	Annual Expenditure on City and Distributed Fast-Charging Stations ($2008)				
	Scenario D				
	Labor	Materials	Trenching/Repairs	Concrete Wk	Permit
	(in-state)	*(out-of-state)*	*(in-state)*	*(in-state)*	*(gov revenue)*
2013	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2014	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2015	$19,356.00	$156,792.00	$4,137.00	$4,137.00	$255.00
2016	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2017	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2018	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2019	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00
2020	$25,808.00	$209,056.00	$5,516.00	$5,516.00	$340.00
2021	$19,356.00	$156,792.00	$4,137.00	$4,137.00	$255.00
2022	$12,904.00	$104,528.00	$2,758.00	$2,758.00	$170.00

Charging Unit Costs for EVs and PHEVs – Scenario E

Home Charger Purchase Expenditures by Year

annual expenditure on **Level-1** Chargers:	*(thousand 2008$)*			annual expenditure on **Level-2** Chargers:	*(thousand 2008$)*		
Labor	**Materials**	**Permit**	Total	**Labor**	**Materials**	**Permit**	Total
(in-state)	*(out-of-state)*	*(gov revenue)*		*(in-state)*	*(out-of-state)*	*(gov revenue)*	
$114.43	$124.06	$4.22	$242.71	$3,257.44	$3,524.94	$47.41	$6,829.79
$144.91	$157.11	$5.34	$307.36	$2,183.35	$2,362.65	$31.77	$4,577.77
$232.24	$251.79	$8.56	$492.58	$3,095.34	$3,349.53	$45.05	$6,489.91
$746.32	$809.16	$27.50	$1,582.98	$8,497.99	$9,195.85	$123.67	$17,817.52
$643.95	$698.18	$23.72	$1,365.86	$6,559.75	$7,098.44	$95.46	$13,753.64
$749.92	$813.07	$27.63	$1,590.61	$8,551.15	$9,253.37	$124.44	$17,928.97
$943.39	$1,022.84	$34.76	$2,000.99	$8,507.38	$9,206.01	$123.81	$17,837.20
$1,000.53	$1,084.79	$36.86	$2,122.18	$8,076.16	$8,739.38	$117.53	$16,933.07
$1,085.29	$1,176.68	$39.98	$2,301.95	$9,217.51	$9,974.45	$134.14	$19,326.10
$1,139.36	$1,235.31	$41.98	$2,416.65	$9,885.41	$10,697.21	$143.86	$20,726.49
$1,231.35	$1,335.04	$45.37	$2,611.76	$12,367.57	$13,383.21	$179.99	$25,930.77

(No additional Level-2 or Level-3 public chargers in this scenario.)

Compressed Natural Gas Costs, by Scenario

CNG Refueling Station Installation Costs

Expenditures ($2008 million)	Scenarios A-C, F-H		Scenario D		One-Pool Scenario	
	Capital	Labor	Capital	Labor	Capital	Labor
2012	$1.08	$1.08	$4.30	$4.30	$1.08	$1.08
2013	$0.00	$2.15	$3.23	$3.23	$0.00	$0.00
2014	$0.00	$1.08	$4.30	$4.30	$0.00	$0.00
2015	$0.00	$1.08	$4.30	$4.30	$0.00	$0.00
2016	$0.00	$1.08	$3.23	$3.23	$0.00	$0.00
2017	$1.08	$2.15	$4.30	$4.30	$1.08	$1.08
2018	$0.00	$1.08	$3.23	$3.23	$0.00	$0.00
2019	$0.00	$1.08	$4.30	$4.30	$0.00	$0.00
2020	$0.00	$1.08	$4.30	$4.30	$0.00	$0.00
2021	$0.00	$2.15	$3.23	$3.23	$0.00	$0.00
2022	$0.00	$1.08	$4.30	$4.30	$0.00	$0.00

Medium- and Heavy-Duty CNG Trucks (Price Differentials above Conventional Diesel/Gas)

	Expenditures on CNG MDVs and HDVs			
	Medium-Duty		Heavy-Duty	
	Scenario D	All Other	Scenario D	All Other
2012	$48,031,900	$3,180,100	$40,275,000	$2,625,000
2013	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2014	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2015	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2016	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2017	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2018	$20,980,400	$1,404,200	$17,250,000	$1,125,000

2019	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2020	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2021	$20,980,400	$1,404,200	$17,250,000	$1,125,000
2022	$20,691,300	$1,362,900	$16,950,000	$1,425,000

Costs for Landfill Gas Recapture, by Scenario:

Landfill Gas costs for Capture, Cleanup, Introduction to NG Pipeline

Annual Costs (2008$)		Scenarios A-C, F-H	Scenario D	One-Pool Scenario
Materials	*out-of-state*	$28,407,942	$56,815,884	$28,407,942
Labor	*in-state*	$8,227,437	$16,454,874	$8,227,437
Site Prep	*in-state*	$1,831,769	$3,663,538	$1,831,769
Engineering	*in-state*	$6,597,473	$13,194,946	$6,597,473
Permitting	*gov revenue*	$1,102,166	$2,204,332	$1,102,166
Contingency		$3,663,538	$7,327,076	$3,663,538
Total		$49,830,325	$99,660,650	$49,830,325

Ethanol Plant Costs and Timing, by Scenario:

Plant Construction Expenditure in 2008$ millions			
Scenarios			
Apply to: -->	Scen. A-C, E-G	Scen. D	Scen. H
# of plants v BAU	3	2	-1
2012			
2013			
2014			
2015			
2016			
2017			
2018	$113.19		-$113.19
2019	$226.37		-$113.19
2020	$226.37	$226.37	
2021	$113.19	$226.37	
2022			

Plant Operating Costs in 2008$ millions (vs BAU)			
Scenarios			
Apply to: -->	Scen. A-C, E-G	Scen. D	Scen. H
# of plants v BAU	3	2	-1
2012			
2013			
2014			
2015			
2016			
2017			
2018			

2019			
2020	$77.05		-$77.05
2021	$154.11		-$77.05
2022	$231.16	$154.11	-$77.05

New Truck Expenditures	Trucks for Transportation of Ethanol				
	Scenarios A and H	Scenario B	Scenarios C, F and G	Scenario D	One-Pool Scenario
2012					
2013					
2014					
2015					
2016					
2017			$180,000		
2018					
2019		$360,000	$180,000		
2020		$360,000			
2021	$180,000	$360,000	$180,000		
2022	$360,000	$360,000		$180,000	$360,000

Terminal Costs by year ($millions):	Ethanol Terminal Costs						
	Scenarios A and H	Scenario B	Scenario C	Scenario F	Scenario G	Scenario D	One-Pool Scenario (Sc. E)
2012	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2016	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

2017	$0.00	$0.00	$0.00	$0.00	**$0.01**	$0.00	$0.00
2018	$0.00	$0.00	$0.00	$0.00	**$0.01**	$0.00	$0.00
2019	$0.00	**$1.85**	$0.00	$0.00	**$0.02**	$0.00	$0.00
2020	$0.00	**$5.07**	$0.00	$0.00	**$0.05**	$0.00	$0.00
2021	**$1.42**	**$5.38**	**$2.56**	**$2.58**	**$2.52**	$0.00	$0.00
2022	**$5.58**	**$5.10**	**$6.64**	**$6.72**	**$6.38**	**$3.60**	**$6.00**

Biodiesel Plant Construction and Operating Costs:

Plant Capital Cost Assumption:	*(million 2008$)*			
	Scenarios:			
	Scenario A	Scenario B	Scenario D	One-Pool Scenario
# of plants:	1	-1	0	-1
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020	$177.93	-$177.93		-$177.93
2021	$177.93	-$177.93		-$177.93
2022				

New Trucks by 2022 (for transporting Biodiesel):

Scenarios A & H	Scenario B	Scenario C, F & G	Scenario D	One-Pool Scenario
		-$198,000	-$198,000	
		-$198,000	-$198,000	
$594,000				$198,000
$594,000		-$198,000	-$198,000	$198,000

Biodiesel-Related Costs to Upgrade Petroleum Terminals

Upgrade Costs:	Scenarios:					
(million 2008$)	BAU	Scenarios A & H	Scenario B	Scenario C, F & G	Scenario D	One-Pool Scenario
2012		$0.00	$0.00	n/a	$0.00	$0.00
2013		$0.00	$0.00	n/a	$0.00	$0.00
2014		$0.00	$0.00	n/a	$0.00	$0.00
2015		$0.00	$0.00	n/a	$0.00	$0.00
2016		$0.00	$0.00	n/a	-$0.01	$0.00
2017		$0.00	$0.00	n/a	-$0.01	$0.00

2018		$0.00	$0.00	n/a	-$0.01	$0.00
2019		$0.00	$0.00	n/a	-$0.01	$0.00
2020		$0.00	$0.00	n/a	-$0.01	$0.00
2021		$0.00	$0.00	n/a	-$0.02	$0.08
2022		$0.50	$0.10	n/a	-$0.02	$0.32

In addition, many values were developed outside of the VISION framework in an effort to establish a complete assessment of the expected direct and induced costs reasonable to expect under each scenario. This set of inputs was developed by DEQ and consultants, led by TIAX LLC. The final memorandum of understanding regarding these inputs can be found in Appendix C of the Oregon Low Carbon Fuel Standards Report.

Appendix B: REMI PI+ Results

Gross State Product Impacts, Eight Scenarios; Measured as $ Change from Baseline

Category	Units		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gross Domestic Product A	Billions of Fixed (2000) Dollars	**Scenario A**	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.15	$0.29	$0.30	$0.19	$0.05
Gross Domestic Product B	Billions of Fixed (2000) Dollars	**Scenario B**	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.17	$0.30	$0.23	$0.13	$0.05
Gross Domestic Product C	Billions of Fixed (2000) Dollars	**Scenario C**	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.16	$0.30	$0.29	$0.18	$0.06
Gross Domestic Product D	Billions of Fixed (2000) Dollars	**Scenario D**	$0.12	$0.11	$0.12	$0.12	$0.14	$0.16	$0.15	$0.17	$0.44	$0.41	$0.20
Gross Domestic Product E	Billions of Fixed (2000) Dollars	**Scenario E**	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.18	$0.32	$0.26	$0.11	$0.05
Gross Domestic Product F	Billions of Fixed (2000) Dollars	**Scenario F**	$0.01	$0.01	$0.02	$0.02	$0.02	$0.03	$0.16	$0.30	$0.32	$0.22	$0.12
Gross Domestic Product G	Billions of Fixed (2000) Dollars	**Scenario G**	$0.01	$0.01	$0.00	$0.00	$0.00	$0.01	$0.15	$0.28	$0.28	$0.15	$0.02
Gross Domestic Product H	Billions of Fixed (2000) Dollars	**Scenario H**	$0.01	$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01

Employment Impacts, Measured as Percent Change from Baseline
Presented by Sector

Scenario A

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.99	1.97	1.99	1.05	0.08
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.10	0.10	0.05

Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.07	0.04	0.01
Retail trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.09	0.05	0.04	0.04	0.04	0.06	0.25	0.45	0.45	0.28	0.12
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.01
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.06	0.06	0.03	(0.00)
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.01	(0.00)
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.01)
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.09	0.05	0.01
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.12	0.24	0.25	0.15	0.03

Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.00
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.11	0.20	0.20	0.11	0.02
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.06	0.04	0.02
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.20	0.20	0.09	(0.00)
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.06	0.04	0.02
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.04	0.02
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.09	0.06	0.03
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.02	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	(0.00)
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.14	0.15	0.10	0.05
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.01
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.03	(0.00)
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.05	0.03	0.01
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.08	0.04	(0.00)

Scenario B

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support	% Change in	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)

activities; Other	Jobs															
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	1.00	1.98	1.90	0.94	0.03
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	% Change in	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Jobs															
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.03	0.05
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.05	0.02	0.01
Retail trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.09	0.06	0.05	0.05	0.05	0.09	0.31	0.50	0.32	0.27	0.07
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.01	0.00
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.04	0.01	(0.00)
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.02	0.00	(0.00)
Insurance carriers and related	% Change in	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	(0.00)	(0.00)

activities	Jobs															
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.05	0.10	0.06	0.03	0.01
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.13	0.25	0.20	0.10	0.03
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.12	0.21	0.14	0.07	0.02
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.04	0.02	0.02
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.12	0.21	0.10	0.01	(0.00)
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.02
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.01
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.09	0.06	0.03	0.03
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.02	0.01	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.01	0.01
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.08	0.15	0.11	0.06	0.04
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.03	0.01	0.01
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.03	0.00	(0.00)
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.03	0.02	0.01
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.04	0.00	(0.00)

Scenario C

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	1.00	1.98	1.99	1.04	0.08
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.05	0.05	0.05
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.07	0.04	0.01
Retail trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.09	0.06	0.05	0.05	0.05	0.07	0.27	0.46	0.45	0.29	0.13
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.02	0.00
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00

Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.06	0.03	(0.00)
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.01	(0.00)
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.05	0.09	0.09	0.06	0.02
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.13	0.25	0.24	0.14	0.04
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.11	0.20	0.20	0.11	0.02
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.04	0.02
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.11	0.21	0.19	0.09	(0.01)
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.06	0.04	0.02
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.05	0.04	0.02
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.09	0.06	0.03
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.02	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	(0.00)
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.08	0.15	0.15	0.10	0.05
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.01
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.03	(0.00)
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01

Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.07	0.03	(0.00)

Scenario D

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Construction	% Change in Jobs	0.00	0.00	0.01	0.02	0.10	0.13	0.15	0.16	0.19	0.21	0.20	0.21	2.09	2.11	0.28
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.03	0.03	0.01
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Miscellaneous manufacturing	% Change	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00

	in Jobs															
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.03	0.04
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.11	0.11	0.06
Retail trade	% Change in Jobs	0.00	0.00	0.10	0.13	1.27	0.89	0.86	0.89	0.92	0.96	0.95	0.99	1.43	1.07	0.78
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.05	0.05	0.02
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Motion picture and sound	% Change	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00

recording industries	in Jobs															
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.08	0.07	0.01
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.00
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.03	0.02	0.00
Real estate	% Change in Jobs	0.00	0.00	0.00	0.01	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.14	0.14	0.07
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.01
Professional and technical services	% Change in Jobs	0.00	0.00	0.01	0.01	0.07	0.07	0.07	0.07	0.09	0.10	0.09	0.10	0.33	0.31	0.12
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.05	0.04	0.02
Administrative and support services	% Change in Jobs	0.00	0.00	0.01	0.01	0.09	0.08	0.09	0.08	0.10	0.11	0.10	0.11	0.29	0.27	0.11
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.12	0.12	0.02	0.02	0.02	0.02	0.02
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.08	0.09	0.05
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.01	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.05	0.24	0.22	0.04
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.08	0.08	0.04
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.07	0.08	0.04
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.13	0.13	0.08
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.05	0.04	0.02
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.06	0.06	0.03
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.01

Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.01	0.04	0.05	0.06	0.06	0.07	0.08	0.08	0.09	0.22	0.22	0.13
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.02	0.03	0.02	0.02	0.05	0.05	0.02
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.07	0.07	0.01
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.07	0.07	0.04
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.10	0.09	0.02

Scenario E

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.04	0.04	1.03	2.01	1.95	0.97	0.06
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.01	0.01	0.01	0.00	(0.00)
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	(0.00)
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	(0.00)	(0.00)	(0.00)

Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	(0.00)	(0.00)
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.03	0.05
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.05	0.08	0.06	0.02	0.01
Retail trade	% Change in Jobs	0.00	0.00	0.09	0.06	0.18	0.25	0.21	0.26	0.26	0.28	0.50	0.71	0.62	0.20	0.19
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.01	0.00
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.04	0.00	(0.00)
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.02	(0.00)	(0.00)
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	(0.00)	(0.01)
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.06	0.10	0.07	0.02	0.01
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.14	0.25	0.21	0.08	0.02
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.02	0.03	0.02	0.00	0.00
Administrative and support services	% Change in Jobs	0.00	0.00	0.01	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.12	0.21	0.16	0.05	0.01
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.06	0.05	0.02	0.02
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.12	0.21	0.11	0.00	(0.01)
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.04	0.02	0.02

Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.02
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.05	0.09	0.07	0.03	0.03
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.02	0.01	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.01	0.01
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	(0.00)	(0.00)
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.09	0.15	0.12	0.06	0.04
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.03	0.01	0.01
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.06	0.03	0.00	(0.00)
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.01
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.04	0.00	(0.00)

Scenario F

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.04	0.05	1.01	1.99	2.02	1.11	0.18

Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.05	0.05	0.06
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.05	0.08	0.09	0.06	0.04

Retail trade	% Change in Jobs	0.00	0.00	0.01	0.02	0.09	0.07	0.07	0.08	0.09	0.13	0.31	0.52	0.54	0.45	0.38
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.04	0.04	0.03	0.01
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.07	0.06	0.04	0.01
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.01	0.00
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.06	0.10	0.11	0.07	0.04
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00

Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.14	0.25	0.26	0.17	0.08
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.02	0.01
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.12	0.21	0.22	0.14	0.07
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.03	0.06	0.07	0.05	0.03
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.11	0.21	0.20	0.11	0.02
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.06	0.06	0.04	0.02
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.06	0.04	0.02
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.05	0.09	0.10	0.07	0.04
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.01
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.02
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.08	0.15	0.17	0.12	0.08
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.02
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.03	0.01
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.05	0.04	0.02
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.08	0.08	0.04	0.01

Scenario G

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.98	1.96	1.97	1.01	0.02
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	(0.00)
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Fabricated metal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.05	0.05	0.05
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.07	0.03	(0.01)
Retail trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.09	0.05	0.04	0.04	0.04	0.05	0.24	0.44	0.42	0.21	(0.01)
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.02	(0.00)
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Internet publishing and broadcasting; ISPs, search portals, and	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)

data processing; Other information services																
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.06	0.06	0.02	(0.01)
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.02	0.01	(0.00)
Insurance carriers and related activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.01)
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.09	0.05	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.23	0.23	0.12	0.01
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.10	0.19	0.18	0.09	(0.00)
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.01	0.01
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.06	0.04	0.01
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.20	0.19	0.08	(0.02)
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.05	0.04	0.01
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.09	0.06	0.02
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.02	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.00

Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.14	0.14	0.09	0.03
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.00
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.05	0.02	(0.01)
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.05	0.03	0.01
Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.08	0.07	0.03	(0.01)

Scenario H

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00
Agriculture and forestry support activities; Other	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Wood product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

manufacturing																
Machinery manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Chemical manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastics and rubber product manufacturing	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Wholesale trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retail trade	% Change in Jobs	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Air transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transit and ground passenger transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Securities, commodity contracts, investments	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance carriers and	% Change	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

related activities	in Jobs															
Real estate	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Management of companies and enterprises	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	% Change in Jobs	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste management and remediation services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.54	1.51	0.09	0.09	0.09
Educational services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hospitals	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Membership associations and organizations	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Private households	% Change in Jobs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Income Impacts, Measured as Percent Change from Baseline
Presented by Sector

Scenario A

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.01	0.26	0.52	0.56	0.34	0.08
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.14	0.28	0.31	0.20	0.07
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.07	0.04	0.02
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.01
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.18	0.09	(0.00)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.01
Plus: Adjustment for residence	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.04)	(0.03)	(0.01)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.22	0.44	0.47	0.28	0.06
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.21	0.43	0.48	0.31	0.10
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.07	0.04	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.18	0.37	0.41	0.27	0.09

Scenario B

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.27	0.53	0.36	0.15	0.07
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.15	0.29	0.25	0.15	0.06
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.05	0.03	0.01
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.06	(0.04)	(0.00)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.04	0.02	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Plus: Adjustment for residence	% Change in Income	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.03)	(0.02)	(0.01)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.02	0.01
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.23	0.45	0.29	0.11	0.05
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.02)	(0.01)	0.01	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.22	0.45	0.30	0.13	0.08
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.04	0.02	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.19	0.38	0.26	0.11	0.07

Scenario C

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.27	0.53	0.55	0.33	0.08
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.15	0.29	0.31	0.20	0.07
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.07	0.04	0.02
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.01
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.18	0.09	(0.00)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.01
Plus: Adjustment for residence	% Change in Income	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.04)	(0.02)	(0.01)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.01
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.22	0.45	0.46	0.28	0.06
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.22	0.44	0.47	0.30	0.10
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.07	0.04	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.19	0.38	0.41	0.26	0.09

Scenario D

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.01	0.01	0.10	0.10	0.11	0.11	0.14	0.15	0.15	0.16	0.67	0.68	0.22
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.01	0.01	0.08	0.08	0.09	0.09	0.11	0.12	0.12	0.13	0.40	0.41	0.18
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.09	0.09	0.04
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.06	0.06	0.03
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.02
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.18	0.18	(0.00)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.07	0.07	0.03
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.02
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.02
Plus: Adjustment for residence	% Change in Income	0.00	0.00	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.05)	(0.05)	(0.02)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.05	0.05	0.02
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.01	0.01	0.08	0.08	0.09	0.08	0.11	0.12	0.11	0.12	0.56	0.57	0.17
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.04	0.05	0.05
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	0.00	0.00	0.00	0.01	0.01	(0.00)	0.01	0.04
Equals: Personal Income	% Change in Income	0.00	0.00	0.01	0.01	0.07	0.08	0.09	0.10	0.12	0.14	0.14	0.16	0.59	0.62	0.26
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.08	0.08	0.03
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.01	0.06	0.07	0.08	0.08	0.11	0.12	0.13	0.14	0.51	0.54	0.23

Scenario E

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.01	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.29	0.55	0.39	0.13	0.07
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.16	0.31	0.28	0.14	0.06
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.07	0.06	0.03	0.01
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.01
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.06	(0.04)	(0.01)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.04	0.02	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.02	0.01	0.00
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.01
Plus: Adjustment for residence	% Change in Income	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.03)	(0.02)	(0.01)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.03	0.02	0.01
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.24	0.46	0.31	0.09	0.05
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.03
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.00)	0.01	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.03	0.03	0.24	0.47	0.33	0.13	0.10
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.07	0.05	0.02	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.21	0.40	0.29	0.12	0.09

Scenario F

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.26	0.53	0.57	0.37	0.14
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.14	0.29	0.32	0.23	0.12
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.06	0.07	0.05	0.03
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.05	0.03	0.02
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.01
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.18	0.09	(0.00)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.04	0.02
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.01
Plus: Adjustment for residence	% Change in Income	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.04)	(0.03)	(0.01)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.22	0.44	0.48	0.31	0.11
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.03	0.03
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)	0.01	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.22	0.45	0.50	0.34	0.16
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.07	0.05	0.02
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.19	0.38	0.43	0.30	0.14

Scenario G

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.26	0.52	0.54	0.31	0.04
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.14	0.28	0.29	0.18	0.04
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.04	0.01
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.18	0.09	(0.01)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.00
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Plus: Adjustment for residence	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.04)	(0.02)	(0.00)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.00
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.22	0.44	0.45	0.26	0.03
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.43	0.46	0.28	0.06
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.04	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.37	0.39	0.24	0.06

Scenario H

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Earnings by Place of Work	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.26	0.52	0.54	0.31	0.04
Total Wage and Salary Disbursements	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.14	0.28	0.29	0.18	0.04
Supplements to Wages and Salaries	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.04	0.01
Employer contributions for employee pension and insurance funds	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.03	0.01
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Proprietors' income with inventory valuation and capital consumption adjustments	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.18	0.18	0.09	(0.01)
Less: Contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.05	0.03	0.01
Employee and self-employed contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.00
Employer contributions for government social insurance	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Plus: Adjustment for residence	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.04)	(0.04)	(0.02)	(0.00)
Gross In	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gross Out	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.02	0.00
Equals: Net earnings by place of residence	% Change in Income	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.22	0.44	0.45	0.26	0.03
Plus: Rental, Personal interest, and Personal dividend income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02
Plus: Personal current transfer receipts	% Change in Income	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	(0.01)	(0.02)	(0.01)	0.00	0.02
Equals: Personal Income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.43	0.46	0.28	0.06
Less: Personal current taxes	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.06	0.04	0.01
Equals: Disposable personal income	% Change in Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.37	0.39	0.24	0.06

Value Added Impacts, Measured as Percent Change from Baseline
Presented by Sector

Scenario A

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.17	0.17	0.09	0.01
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.04	0.04	0.02
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.02	0.05	0.05	0.03	0.01
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00

Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	(0.00)
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario B

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.09	0.09	0.04	0.00
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.02	0.02	0.01
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds,	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)

trusts, & other financial vehicles																
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	(0.00)
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario C

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.09	0.09	0.05	0.01
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.02	0.01
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds,	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)

trusts, & other financial vehicles																
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	(0.00)
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario D

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.09	0.10	0.01
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.01
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.01	0.07	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.10	0.08	0.06
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds,	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00

trusts, & other financial vehicles																
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.01
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario E

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.09	0.05	0.00
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.05	0.04	0.02	0.02
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00	0.00	(0.00)	(0.00)	(0.00)
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	(0.00)
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds,	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	(0.00)

trusts, & other financial vehicles																
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	(0.00)
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario F

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.09	0.05	0.01
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.04	0.04	0.03	0.03
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds,	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00

trusts, & other financial vehicles																
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.01
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario G

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.09	0.09	0.05	0.00
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Fabricated metal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	(0.00)
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.02	(0.00)
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation; Couriers and messengers	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Insurance carriers and related activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.01	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	(0.00)
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)

	(2000) Dollars															

Scenario H

Category	Units	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forestry and logging; Fishing, hunting, and trapping	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Agriculture and forestry support activities; Other	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil and gas extraction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining (except oil and gas)	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Wood product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary metal manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabricated metal product manufacturing	Billions of Fixed (2000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Dollars															
Machinery manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer and electronic product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment and appliance manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicles, bodies & trailers, and parts manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Furniture and related product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beverage and tobacco product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	0.00
Textile product mills	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Apparel manufacturing	Billions of Fixed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)

	(2000) Dollars															
Leather and allied product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paper manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum and coal product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Chemical manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastics and rubber product manufacturing	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retail trade	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Air transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)
Water transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00
Truck transportation; Couriers	Billions of	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(0.02)	(0.01)	0.00	0.00

and messengers	Fixed (2000) Dollars															
Transit and ground passenger transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Pipeline transportation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.01
Scenic and sightseeing transportation; support activities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Warehousing and storage	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Publishing industries, except Internet	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture and sound recording industries	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internet publishing and broadcasting; ISPs, search portals, and data processing; Other information services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Broadcasting, except Internet; Telecommunications	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monetary authorities - central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Securities, commodity contracts, investments	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance carriers and related activities	Billions of Fixed (2000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)

	Dollars															
Real estate	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rental and leasing services; Lessors of nonfinancial intangible assets	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Professional and technical services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Management of companies and enterprises	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Administrative and support services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste management and remediation services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.55	1.51	0.10	0.10	0.10
Educational services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ambulatory health care services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hospitals	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nursing and residential care facilities	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Social assistance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts and spectator sports	Billions of Fixed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(0.02)	(0.02)	(0.02)	(0.01)

	(2000) Dollars															
Museums, historical sites, zoos, and parks	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food services and drinking places	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Repair and maintenance	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.01)	(0.01)	(0.01)
Personal and laundry services	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Membership associations and organizations	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Private households	Billions of Fixed (2000) Dollars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

JOHN A. KITZHABER, MD
Governor

April 17, 2012

Dick Pedersen
Oregon Department of Environmental Quality
811 SW 6th Avenue
Portland, OR 97204

Dear Director Pedersen:

In 2009, the Oregon legislature adopted HB 2186, authorizing the Environmental Quality Commission (EQC) to adopt a low carbon fuel standard to reduce greenhouse gas emissions from transportation fuels. Since then, the Department of Environmental Quality (DEQ) has conducted an extensive technical and economic analysis of the policy, and you have also listened carefully to the views of stakeholders and the public. At this time, I would like you to take the next step in investigating a clean fuel standard by developing rules to implement it in two phases.

Reducing greenhouse gas emissions is among the most important challenges of our time. This is important not only to begin addressing the threat of global warming, but also to reduce our nation's dependence on imported petroleum, stimulate jobs throughout the nation to produce clean energy and save consumers money. Because transportation accounts for a third of Oregon's greenhouse gas emissions, we must tackle emissions from this sector in order to reach our goals. To address these emissions effectively, we must begin the process of transforming our transportation infrastructure to support a diversity of low carbon fuels. The clean fuels standard is a key step in this transformation, by allowing producers of all types of low carbon fuels to compete to meet our transportation fuel needs.

As urgent as this need is, we must continue to move deliberately to ensure that the clean fuel standard is implemented in a way that ensures adequate fuel supplies, and that does not cause increases in fuel prices. For this reason, I suggest you develop the standard in two phases. During Phase 1, fuel suppliers would begin to track and report the carbon intensity of transportation fuels over a two year period. During Phase 2, which would be triggered by the

EQC only after a successful conclusion of Phase 1, fuel suppliers would be required to meet the standard. This two phase approach will allow DEQ to assess the availability of low carbon fuels, adjust the program as needed to meet legal requirements, prepare for full implementation, and continue to seek public input before fuel suppliers are required to meet the standard.
As you know, Oregon is separately developing a ten-year energy action plan to:

- Reduce our dependence on carbon-intensive fuels and foreign oil;
- Develop home-grown renewable energy resources;
- Mitigate greenhouse gas emissions;

254 STATE CAPITOL, SALEM OR 97301-4047 (503) 373-3111 FAX (503) 378-4863
WWW.OREGON.GOV

- Improve energy efficiency and create rewarding local jobs; and
- Boost Oregon's economy through investment and innovation.

The clean fuels standard supports these goals and will be important to the success of this plan. It is also a central component of our statewide greenhouse gas reduction strategy for transportation being developed in response to SB 1059 adopted in 2010 and HB 2001 adopted in 2009.

For all of these reasons, I am asking you to propose the clean fuels standard for consideration by the Environmental Quality Commission, with a decision to be made by the end of this year. I ask you to work closely with legislators, both to keep them informed about this proposed course of action, and to request the legislative action necessary to implement the program fully.

Sincerely,

John A. Kitzhaber, M.D.
Governor

cc: Bill Blosser, Chair, Environmental Quality Commission
Richard Whitman, Senior Natural Resource Policy Advisor to Governor Kitzhaber