FOR PUBLICATION

UNITED STATES COURT OF APPEALS FOR THE NINTH CIRCUIT

AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS; AMERICAN TRUCKING ASSOCIATIONS, INC., a trade association; CONSUMER ENERGY ALLIANCE, a trade association,
Plaintiffs-Appellants,

v.

JANE O'KEEFFE; ED ARMSTRONG; MORGAN RIDER; COLLEEN JOHNSON; MELINDA EDEN; DICK PEDERSEN; JONI HAMMOND; WENDY WILES; DAVID COLLIER; JEFFREY STOCUM; CORY-ANN WIND; LYDIA EMER; LEAH FELDON; GREG ALDRICH; and SUE LANGSTON, in their official capacities as officers and employees of the Oregon Department of Environmental Quality; ELLEN F. ROSENBLUM, in her official capacity as Attorney General of the State of Oregon; KATE BROWN, in her official capacity as Governor of the State of Oregon,
Defendants-Appellees,

No. 15-35834

D.C. No. 3:15-cv-00467-AA

OPINION

CALIFORNIA AIR RESOURCES BOARD; STATE OF WASHINGTON; OREGON ENVIRONMENTAL COUNCIL; SIERRA CLUB; NATURAL RESOURCES DEFENSE COUNCIL; ENVIRONMENTAL DEFENSE FUND; CLIMATE SOLUTIONS,
Intervenor-Defendants-Appellees.

Appeal from the United States District Court
for the District of Oregon
Ann L. Aiken, District Judge, Presiding

Argued and Submitted March 6, 2018
Portland, Oregon

Filed September 7, 2018

Before: Raymond C. Fisher, N. Randy Smith,
and Andrew D. Hurwitz, Circuit Judges.

Opinion by Judge Hurwitz;
Dissent by Judge N.R. Smith

SUMMARY[*]

Civil Rights

The panel affirmed the district court's dismissal of a complaint challenging Oregon's Clean Fuels Program, which regulates the production and sale of transportation fuels based on greenhouse gas emissions.

Plaintiffs, the American Fuel and Petrochemical Manufacturers, American Trucking Associations, and Consumer Energy Alliance, alleged that the Oregon Program violated the Commerce Clause and was preempted by § 211(c) of the Clean Air Act.

Addressing the Commerce Clause claim, the panel held that plaintiffs' assertion that the Oregon Program facially discriminates against out-of-state fuels by assigning petroleum and Midwest ethanol higher carbon intensities than Oregon biofuels was squarely controlled by *Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070, 1081 (9th Cir. 2013). The panel held that like the California Low Carbon Fuel Standard at issue in *Rocky Mountain*, the Oregon Program discriminated against fuels based on lifecycle greenhouse gas emissions, not state of origin.

The panel held that the complaint failed to plausibly allege that the Oregon Program was discriminatory in purpose. The panel held that none of the alleged discriminatory statements cited by plaintiffs undermined the

[*] This summary constitutes no part of the opinion of the court. It has been prepared by court staff for the convenience of the reader.

Oregon Program's stated purpose of reducing greenhouse gas emissions. The panel rejected plaintiff's claim that that the Oregon Program's assignment of carbon intensity credits and deficits effectuated a discriminatory effect. The panel also rejected the claim that the Oregon Program violates the Commerce Clause and principles of interstate federalism by attempting to control commerce occurring outside the boundaries of the state.

Addressing the preemption claim, the panel held that the Environmental Protection Agency's decision not to regulate methane under § 211(k) of the Clean Air Act was not a finding that regulating methane's contributions to greenhouse gas emissions was unnecessary, and thus the decision not to regulate was not preemptive under § 211(c)(4)(A)(i).

Dissenting, Judge N.R. Smith stated that he could not dismiss plaintiffs' claim alleging that the practical effect of the Oregon Program impermissibly favored in-state interests at the expense of out-of-state interests.

COUNSEL

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Amanda W. Goodin and Patti A. Goldman, Earthjustice, Seattle, Washington; David Pettit, Natural Resources Defense Council, Santa Monica, California; Joanne Spalding, Sierra Club, Oakland, California; Sean H. Donahue, Donahue & Goldberg LLP, Washington, D.C.; for Intervenor-Defendants-Appellees Oregon Environmental Council, Sierra Club, Natural Resources Defense Council, Environmental Defense Fund, and Climate Solutions.

Margaret Elaine Meckenstock (argued), Deputy Attorney General; Gavin G. McCabe, Supervising Deputy Attorney General; Robert W. Byrne, Senior Assistant Attorney General; Office of the Attorney General, Oakland, California; Thomas J. Young, Senior Counsel; Robert W. Ferguson, Attorney General; Office of the Attorney General, Olympia, Washington; for Intervenor-Defendants-Appellees California Air Resources Board and State of Washington.

OPINION

HURWITZ, Circuit Judge:

This case requires us to decide whether an Oregon program regulating the production and sale of transportation fuels based on greenhouse gas emissions violates the Commerce Clause, U.S. Const. art. I, § 8, cl. 3, or is preempted by § 211(c) of the Clean Air Act ("CAA"), 42 U.S.C. §§ 7401, 7545. The district court dismissed a complaint challenging the Oregon program. We affirm.

I. Background

A. The Oregon Program

In 2007, the Oregon legislature found that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources and environment of Oregon," and identified "a need to . . . take necessary action to begin reducing greenhouse gas emissions." Or. Rev. Stat. § 468A.200(3), (7). The legislature accordingly created the Oregon Clean Fuels Program (the "Oregon program") and instructed the Oregon Environmental Quality Commission ("OEQC") to adopt rules to decrease lifecycle greenhouse gas emissions from transportation fuels produced in or imported into Oregon. Or. Rev. Stat. §§ 468A.266–268. Between 2010 and 2015, the OEQC promulgated rules designed to reduce greenhouse gas emissions from use and production of transportation fuels in Oregon to at least 10%

lower than 2010 levels by 2025. *See* Or. Admin. R. 340-253-0000-8100.[1]

Under these rules, a regulated party must keep the average carbon intensity[2] of all transportation fuels used in Oregon below an annual limit. *See id.* 340-253-0100(6), -8010, -8020. The annual carbon intensity limits become more stringent annually through 2025. *See id.*[3]

A fuel with a carbon intensity below the limit generates a credit, and one with a carbon intensity above the limit generates a deficit. *See id.* 340-253-0040(30), (35), -1000(5). Regulated parties must generate carbon intensity "credits" greater than or equal to their "deficits" on an annual basis. Regulated parties can buy or sell credits, store them for future use, or use them to offset immediate deficits. Thus, a "regulated party may demonstrate compliance in each compliance period either by producing or importing fuel that in the aggregate meets the standard or by obtaining sufficient credits to offset the deficits it has incurred for such fuel produced or imported into Oregon." *Id.* 340-253-0100(6).

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[1] The regulations were incorporated by reference into American Fuel's complaint. The parties have also included the regulations in motions for judicial notice, Dkt. 13, 37, 52, which we **GRANT.**

[2] "'Carbon intensity' or 'CI' means the amount of lifecycle greenhouse gas emissions per unit of energy of fuel expressed in grams of carbon dioxide equivalent per megajoule (gCO2e/MJ)." Or. Admin. R. 340-253-0040(20).

[3] Regulated fuel importers or producers must (1) register with the Oregon Department of Environmental Quality ("ODEQ") and (2) report the volumes and carbon intensities of their transportation fuels. Or. Admin. R. 340-253-0100.

The cumulative carbon intensity value attributed to the lifecycle of a particular type of fuel is called a "pathway." *Id.* 340-253-0040(46) ("'Fuel pathway' means a detailed description of all stages of fuel production and use for any particular transportation fuel, including feedstock generation or extraction, production, distribution, and combustion of the fuel by the consumer. The fuel pathway is used to calculate the carbon intensity of each transportation fuel."); *see also Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070, 1081 (9th Cir. 2013) (noting a similar definition in California's Low Carbon Fuel Standard ("LCFS")). The first phase of Oregon rules provided tables with default pathways for various fuels, "including feedstock generation or extraction, production, distribution, and combustion of the fuel by the consumer." Or. Admin. R. 340-253-0040(46), -0400(1). During this phase, regulated parties could either use the default pathways, or seek approval for individualized pathways. *Id.* 340-253-0400(3), -0450.

The second phase of the Oregon rules introduced a scientific modeling tool called OR-GREET, based on "the Greenhouse gases, Regulated Emissions, and Energy in Transportation (GREET) model developed by Argonne National Laboratory" to calculate individualized pathways for non-petroleum fuels. *Id.* 340-253-0040(67), -0400(1); *see also Rocky Mountain*, 730 F.3d at 1080–84 (describing California LCFS, which also uses GREET modeling tools). The OR-GREET employs a "lifecycle analysis" to determine total carbon intensity, which includes emissions from the production, storage, transportation, and use of the fuels, thus accounting for "all stages of fuel production." Or. Admin. R. 340-253-0040(46). The lifecycle analysis allows a state to account for "the climate-change benefits of biofuels such as ethanol, which mostly come before combustion." *Rocky Mountain*, 730 F.3d at 1081. Lifecycle analysis also allows for an accurate comparison of the carbon effects of fuels produced using different production methods and source materials. *See id.* ("An accurate comparison is possible only when it is based on the entire lifecycle emissions of each fuel pathway.").

Producers and importers of ethanols and biodiesels can obtain carbon intensity scores in one of three ways. If a fuel has been assigned a carbon intensity score under the California LCFS, a regulated party can have that value adjusted for use in Oregon. Or. Admin. R. 340-253-0400(4)(a). Regulated parties can also use individualized carbon intensity scores calculated using the OR-GREET modeling tool. *Id.* 340-253-0500. If it is not possible to obtain an individualized value, a regulated party may also use a default pathway to report carbon intensity. *See id.* 340-253-0450.[4] "Thus fuel producers can take advantage of default and individualized carbon intensity values, and choose what is most advantageous." *Rocky Mountain*, 730 F.3d at 1082.

Because of the uniquely harmful environmental effects of petroleum-based fuels, importers of petroleum-based gasoline and diesel—unlike producers and importers of other fuels—are required to use average carbon intensity pathways, based on the average carbon-intensity values of such fuels in Oregon.[5] Or. Admin R. 340-253-0400(3)(a).

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[4] The second phase of rules provides two default ethanol pathways—Midwest and Oregon averages—which assume production using the same inputs but different energy sources. Or. Admin. R. 340-253-8030, tbl. 3. These pathways are used only until an individual pathway is approved. *Id.* 340-253-0400(4)(b), -0450(3).

[5] *See Rocky Mountain*, 730 F.3d at 1084 ("Crude oil presents different climate challenges from ethanol and other biofuels. Corn and

This requirement was designed to promote the use and development of alternative fuels, because reliance solely on petroleum-based fuels would make targeted emissions reductions unattainable. *See Rocky Mountain*, 730 F.3d at 1085 ("No matter how efficiently crude oil is extracted and refined, it cannot supply [the targeted] level of reduction. To meet California's ambitious goals, the development and use of alternative fuels must be encouraged.").

B. Procedural Background

In March 2015, the American Fuel and Petrochemical Manufacturers, American Trucking Associations, and Consumer Energy Alliance (collectively, "American Fuel") filed this action against officials of the ODEQ and OEQC (the "Oregon defendants"), alleging that the Program violated the Commerce Clause and was preempted by § 211(c) of the CAA.[6] The district court granted motions to

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sugarcane absorb carbon dioxide as they grow, offsetting emissions released when ethanol is burned. By contrast, the carbon in crude oil makes a one-way trip from the Earth's crust to the atmosphere. For crude oil and its derivatives, emissions from combustion are largely fixed, but emissions from production vary significantly. As older, easily accessible sources of crude are exhausted, they are replaced by newer sources that require more energy to extract and refine, yielding a higher carbon intensity than conventional crude oil.").

[6] The plaintiffs are national trade associations. American Fuel's members include nearly all United States refiners and petrochemical manufacturers, and sell transportation fuels throughout Oregon. A number of American Fuel's members produce and sell gasoline, diesel, and ethanol used as transportation fuels in Oregon, and several import such gasoline, diesel, and ethanol into Oregon. Members of the American Trucking Association purchase transportation fuels in Oregon for use in Oregon. The Consumer Energy Alliance's members include industrial consumers and producers of gasoline, diesel, and ethanol.

intervene by several conservation organizations (the "Conservation Intervenors"),[7] the California Air Resource Board, and the State of Washington (the "State Intervenors"). The Oregon defendants moved to dismiss the complaint for failure to state a claim upon which relief can be granted under Federal Rule of Civil Procedure 12(b)(6), and the State Intervenors moved for judgment on the pleadings under Rule 12(c). The district court granted both motions, finding American Fuel's claims "largely barred" by this court's decision in *Rocky Mountain* about a virtually identical California program. The district court also concluded that the Oregon program did not discriminate in purpose or effect against out-of-state ethanol and was not preempted by the CAA.

We review the district court's judgment de novo, taking well-pleaded allegations of material fact as true and construing the complaint in the light most favorable to American Fuel. *AlliedSignal, Inc. v. City of Phoenix*, 182 F.3d 692, 695 (9th Cir. 1999).

II. The Commerce Clause

The Commerce Clause grants Congress the power "[t]o regulate Commerce with foreign Nations, and among the several States, and with the Indian tribes." U.S. Const. art. I, § 8, cl. 3. Despite its textual focus solely on congressional power, the Clause also "has long been understood to have a 'negative' aspect that denies the States the power unjustifiably to discriminate against or burden the interstate flow of articles of commerce." *Or. Waste Sys., Inc. v. Dep't*

[7] The Conservation Intervenors are the Oregon Environmental Council, the Sierra Club, the Environmental Defense Fund, Climate Solutions, and the Natural Resources Defense Council.

of Envtl. Quality of State of Or., 511 U.S. 93, 98 (1994). This so-called "dormant" Commerce Clause is "driven by concern about 'economic protectionism—that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors.'" *Dep't. of Revenue of Ky. v. Davis*, 553 U.S. 328, 337–38 (2008) (quoting *New Energy Co. of Ind. v. Limbach*, 486 U.S. 269, 273–74 (1988)); *see also South Dakota v. Wayfair, Inc.*, 138 S. Ct. 2080, 2089 (2018) (noting that the Commerce Clause was enacted to combat "the tendencies toward economic Balkanization that had plagued relations among the Colonies and later among the States" (quoting *Hughes v. Oklahoma*, 441 U.S. 322, 325–26 (1979)).

But, courts considering dormant Commerce Clause challenges must "respect a cross-purpose as well, for the Framers' distrust of economic Balkanization was limited by their federalism favoring a degree of local autonomy." *Davis*, 553 U.S. at 338. Thus, we must uphold a nondiscriminatory law against a dormant Commerce Clause challenge "unless the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits." *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

In *Rocky Mountain*, we considered a challenge to the California LCFS, on which the district court accurately noted the Oregon program was modeled and to which it is analogous in all relevant respects. As in the Oregon program, parties regulated under the LCFS generate credits or deficits based on their carbon intensity scores, which are calculated through a GREET modeling tool. *Rocky Mountain*, 730 F.3d at 1080–82. In *Rocky Mountain*, we largely upheld the LCFS against a Commerce Clause challenge, remanding for further proceedings on an issue not addressed by the district court: whether the LCFS discriminated against out-of-state ethanol in purpose or effect. *Id.* at 1078.[8]

We thus begin from the premise established in *Rocky Mountain*: state regulation violates the dormant Commerce Clause if it discriminates against out-of-state economic interests (in either purpose or effect) or if it regulates conduct occurring entirely outside of a state's borders. *Id.* at 1087, 1101–02. In contrast, we will uphold regulations that accord all fuels "the substantially evenhanded treatment demanded by the Commerce Clause." *Id.* at 1094 (quoting *Boston Stock Exch. v. State Tax Comm'n*, 429 U.S. 318, 332 (1977)).

A. Discrimination

i. Facial Discrimination

American Fuel's claim that the Program facially discriminates against out-of-state fuels by assigning petroleum and Midwest ethanol higher carbon intensities

[8] On remand, the district court concluded that the Program did not discriminate in purpose or effect against out-of-state petroleum. *Rocky Mountain Farmers Union v. Goldstene*, No. 1:09-cv-02234, 2014 WL 7004725, at *14–15 (E.D. Cal. Dec. 11, 2014). The court later held that the Program did not purposefully discriminate against out-of-state ethanol, but, because of changes in the manner in which California calculated its carbon intensity scores, twice denied motions to dismiss the claim that the Program had a discriminatory effect on out-of-state ethanol. *Rocky Mountain Farmers Union v. Corey*, 258 F. Supp. 3d 1134, 1158, 1163 (E.D. Cal. 2017); Memorandum Decision and Order, *Rocky Mountain Farmers Union v. Corey*, No. 1:09-cv-02234-LJO-BAM (E.D. Cal. Aug. 3, 2015), ECF No. 343. These subsequent denials are discussed in greater depth in Part II(A)(iii)(a), *infra*. The plaintiffs voluntarily dismissed their remaining claims and filed an appeal, which is pending in this court.

than Oregon biofuels is squarely controlled by *Rocky Mountain*. Like its California counterpart, the Oregon program discriminates against fuels based on lifecycle greenhouse gas emissions, not state of origin. *See Rocky Mountain*, 730 F.3d at 1090.

A state may not discriminate "against articles of commerce coming from outside the State unless there is some reason, apart from their origin, to treat them differently." *City of Philadelphia v. New Jersey*, 437 U.S. 617, 626–27 (1978). But, the Oregon program distinguishes among fuels not on the basis of origin, but rather on carbon intensity. Out-of-state fuels are not necessarily disfavored: when the complaint was filed, the Program assigned twelve out-of-state ethanols, including five Midwest ethanols, lower carbon intensities than those assigned to Oregon biofuels.[9] The fact that the Program labels fuels by state of origin does not render it discriminatory, as these labels are not the basis for any differential treatment. *See Rocky Mountain*, 730 F.3d at 1097 ("California's reasonable decision to use regional categories in its default pathways . . . does not transform its evenhanded treatment of fuels based on their carbon intensities into forbidden discrimination.").

ii. Discriminatory Purpose

Citing statements by former Oregon Governor John Kitzhaber and various Oregon legislators, American Fuel next alleges that the Oregon program was enacted with the

[9] More recent carbon intensity scores—including those submitted with American Fuel's motion for judicial notice—also make plain that out-of-state fuels are not systematically disfavored. *See* Or. Admin. R. 340-253-8030, -8040.

intent to "foster Oregon biofuels production at the expense of existing out-of-state fuel producers." But, the stated purpose of the Program is simply to "reduce Oregon's contribution to the global levels of greenhouse gas emissions and the impacts of those emissions in Oregon"—in particular, to "reduce the amount of lifecycle greenhouse gas emissions per unit of energy by a minimum of 10 percent below 2010 levels by 2025." Or. Admin. R. 340-253-0000(1), (2). "We will 'assume that the objectives articulated by the legislature are actual purposes of the statute, unless an examination of the circumstances forces us to conclude that they could not have been a goal of the legislation.'" *Rocky Mountain*, 730 F.3d at 1097–98 (quoting *Minnesota v. Clover Leaf Creamery Co.*, 449 U.S. 456, 463 n.7 (1981)).

The district court did not err in finding that the statements by Oregon public officials cited in American Fuel's complaint do not demonstrate that the objectives identified by the legislature were not the true goals of the Program. Even construing the allegations in the complaint in the light most favorable to American Fuel, the statements cited, "do not plausibly relate to a discriminatory design and are 'easily understood, in context, as economic defense of a [regulation] genuinely proposed for environmental reasons.'" *Id.* at 1100 n.13 (alteration in original) (quoting *Clover Leaf Creamery Co.*, 449 U.S. at 463 n.7). The statements of the Oregon officials are no more probative of a discriminatory or protectionist purpose than the statements by California state officials we found insufficient to establish discriminatory purpose in *Rocky Mountain*. *Id.*[10]

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[10] *Compare* Mem. in Supp. of Mot. Summ. J., *Rocky Mountain Farmers Union v. Goldstene*, No. 1:09-cv-02234-LJO-BAM (E.D. Cal.

None of the statements cited by American Fuel undermines the Oregon program's stated purpose. One of the allegedly discriminatory statements of former Governor Kitzhaber, for example, explicitly attributed the Program's favorable treatment of biofuels to the fact that "natural gas transmissions and generation emit 50 percent less greenhouse gas than burning coal." *See generally Ashcroft v. Iqbal*, 556 U.S. 662, 678 (2009) ("Where a complaint pleads facts that are 'merely consistent with' a defendant's liability, it 'stops short of the line between possibility and plausibility of entitlement to relief.'" (quoting *Bell Atl. Corp. v. Twombly*, 550 U.S. 544, 557 (2007))).

Our federal system recognizes "each State's freedom to 'serve as a laboratory; and try novel social and economic

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Nov. 1, 2010), ECF No. 112 (quoting remarks by California state officials promoting the benefits of the LCFS, including the prospect that the program would "keep more money in the State" and "ensure that a significant portion of the biofuels used in the LCFS are produced in California"), *with* Compl., *Am. Fuel & Petrochemical Mfrs. v. O'Keeffe*, No. 3:15-cv-00467-AA (D. Or. March 23, 2015), ECF No. 1 (citing statements by former Governor Kitzhaber that the Oregon program would "provide important economic benefits to Oregon's economy" and "keep capital circulating in our region through local sourcing and supply chains while reducing our dependence on carbon-intensive fuels." (quoting J. Kitzhaber, *10-Year Energy Action Plan 37* (Dec. 14, 2012))).

American Fuel also cites a statement from an advisory committee member that the LCFS "will create net jobs, make net improvements for household income, and be beneficial for Oregon's Gross State Product." *See* Advisory Final Report, Appx. A, Summary of Advisory Committee Input at 142 (2010), http://library.state.or.us/repository/2011/20110208 1424462/appendixA.pdf. These statements merely represent feedback and recommendations from stakeholders consulted during the rulemaking process; under the same subheading, another committee member offered the critique that "more can be done to incentivize low carbon fuels within the state." *Id.*

experiments.'" *San Antonio Indep. Sch. Dist. v. Rodriguez*, 411 U.S. 1, 50 (1973) (quoting *New State Ice Co. v. Liebmann*, 285 U.S. 262, 280 (1932) (Brandeis, J., dissenting)). This freedom would be meaningless if officials could not promote the economic benefits of these experiments to their states without running afoul of the Commerce Clause. For this reason, regulations "justified by a valid factor unrelated to economic protectionism" are permissible, even if they benefit a state's economy. *New Energy Co.*, 486 U.S. at 274.

It is well settled that the states have a legitimate interest in combating the adverse effects of climate change on their residents. *Massachusetts v. EPA*, 549 U.S. 497, 522–23 (2007). "Air pollution prevention falls under the broad police powers of the states, which include the power to protect the health of citizens in the state." *Exxon Mobil Corp. v. U.S. Envtl. Prot. Agency*, 217 F.3d 1246, 1255 (9th Cir. 2000). The complaint does not allege that the Oregon program was enacted for the purpose of supporting a uniquely local industry. *Cf. Bacchus Imports, Ltd. v. Dias*, 468 U.S. 263, 271 (1984) (finding a discriminatory purpose behind tax exemptions for two liquors produced in Hawaii because it was "undisputed that the purpose of the exemption was to aid Hawaiian industry"). The district court therefore correctly rejected the argument that the complaint plausibly alleged that the Program was discriminatory in purpose.

iii. Discriminatory Effect

A facially neutral statute can violate the Commerce Clause if it effectuates "differential treatment of in-state and out-of-state interests that benefits the former and burdens the latter." *Or. Waste Sys., Inc.*, 511 U.S. at 99. But, even assuming that the in-state and out-of-state fuels at issue in this case are similarly situated, American Fuel's complaint does not state a claim based on discriminatory effects. *See Rocky Mountain*, 730 F.3d at 1089 ("All factors that affect carbon intensity are critical to determining whether the Fuel Standard gives equal treatment to similarly situated fuels.").

a. Burdens on Out-of-State Fuels

American Fuel argues that the Program's assignment of credits and deficits creates an impermissible burden on producers or importers of petroleum and Midwest ethanols, who must purchase credits, and provides an impermissible benefit to Oregon biofuel producers, who can generate and can sell credits. The argument fails. On its face, the Oregon program assigns credits and deficits to fuels evenhandedly based on a "reason, apart from [their] origin": carbon intensity. *Or. Waste Sys., Inc.*, 511 U.S. at 101 n.5. The number of credits assigned to fuels does not depend on their state of origin. *See also Rocky Mountain*, 730 F.3d at 1089 (finding no discrimination under the LCFS, which "does not base its treatment on a fuel's origin but on its carbon intensity").

And, American Fuel has not plausibly alleged that the application of these neutral criteria has a discriminatory effect. Many out-of-state producers generate credits, and several fare better in this respect than Oregon producers of the same fuels. Indeed, even factoring in transportation emissions does not neatly divide in-state and out-of-state producers, because "[t]ransportation emissions reflect a combination of: (1) distance traveled . . . ; (2) total mass and volume transported; and (3) efficiency of the method of transport." *Id.* at 1083; *see, e.g.*, State of Or. Dep't of Envtl. Quality, Oregon-Approved Carbon Intensity Values for 2016 (2016) (hereinafter "ODEQ 2016 Report") (assigning lower carbon-intensity scores to renewable diesels and biofuels from Arkansas, Louisiana, Texas, South Korea, China, and Canada than to Oregon biofuels, and lower carbon-intensity scores to numerous out-of-state ethanols than to Oregon-produced ethanols); Or. Admin. R. 340-253-8030, -8040. Given its scoring system, the Program does not require or even incentivize "an out-of-state operator to become a resident in order to compete on equal terms." *Halliburton Oil Well Cementing Co. v. Reily*, 373 U.S. 64, 72 (1963).

Under the Oregon program, producers of higher carbon-intensity fuels are disfavored relative to *all* lower carbon-intensity fuels, including those produced outside of Oregon. This is plainly permissible. A state "may regulate with reference to local harms, structuring its internal markets to set incentives for firms to produce less harmful products for sale" within its borders. *Rocky Mountain*, 730 F.3d at 1104; *see also Exxon Corp. v. Governor of Maryland*, 437 U.S. 117, 127 (1978) (holding that "interstate commerce is not subjected to an impermissible burden simply because an otherwise valid regulation causes some business to shift from one interstate supplier to another"). The Commerce Clause "protects the interstate market, not particular interstate firms." *Exxon Corp.*, 437 U.S. at 127.

American Fuel alleges that "to compete in the Oregon market, producers of high carbon-intensity fuels must change the manner in which they produce and transport fuels to obtain lower carbon-intensity scores to avoid the commercial disadvantage placed on their higher carbon-intensity fuels." But this allegation merely affirms that the Program targets differences in production methods that affect greenhouse gas emissions "based on the real risks posed by different sources of generation," something we have squarely held "is not a dormant Commerce Clause violation." *Rocky Mountain*, 730 F.3d at 1092.

This is because the OR-GREET model considers in its calculation of carbon intensities emissions from the growth of inputs into the production of fuels, such as corn; efficiency of production, including electricity or fuel used for energy; milling processes; conversion of land for production; and transportation of fuels and feedstock into its calculations of carbon intensities. *See id.* at 1082–83 (upholding use of analogous GREET model in regulation in California). Accordingly, carbon intensity scores for ethanol vary widely under the Oregon program, ranging in January 2016 from 7.49 (Brazilian sugarcane ethanol) to as high as 98.59 (Midwest coal ethanol). *See* State of Or. Dep't of Envtl. Quality, Oregon-Approved Carbon Intensity Values for 2016 (2016). But, some of the lowest carbon intensity scores are also assigned to Midwest producers. *See id.* at 8–11 (assigning values to Midwest ethanols ETHC036, ETHC056, ETCH073-75, and ETHC089-90 lower than the value of Oregon ethanol). "The dormant Commerce Clause does not require [a state] to ignore the real differences in carbon intensity among out-of-state ethanol pathways," including emissions from transporting fuels and other "important contributors to GHG emissions." *Rocky Mountain*, 730 F.3d at 1088, 1093.

Nor does the Oregon program eliminate a competitive advantage that producers of higher carbon-intensity fuels have earned. *Cf. Hunt v. Wash. State Apple Advert. Comm'n*, 432 U.S. 333, 351 (1977) (striking down a North Carolina regulation that had "the effect of stripping away from the Washington apple industry the competitive and economic advantages it has earned for itself through its expensive inspection and grading system"). A state may favor environmentally friendly production methods over others with more harmful effects. *See Clover Leaf Creamery Co.*, 449 U.S. at 473. And, "[a]ccess to cheap electricity is an advantage, but it was not 'earned' . . . simply because ethanol producers built their plants near coal-fired power plants and imposed the hidden costs of GHG emissions on others." *Rocky Mountain*, 730 F.3d at 1092; *see id.* at 1091–92 ("Drawing electricity from the coal-fired grid might be the easiest and cheapest way to power an ethanol plant. But the dormant Commerce Clause does not guarantee that ethanol producers may compete on the terms they find most convenient."); *see also Exxon Corp.*, 437 U.S. at 127 (holding that the Commerce Clause does not protect "the particular structure or methods of operation in a retail market").

On remand, the *Rocky Mountain* district court held that American Fuel had plausibly alleged a discriminatory effect on out-of-state ethanol in California from the California program. *Rocky Mountain Farmers Union*, 258 F. Supp. 3d at 1163; Mem. Decision & Order, *Rocky Mountain Farmers Union v. Corey*, No. 1:09-cv-02234-LJO-BAM (E.D. Cal. Aug. 3, 2015), ECF No. 343. But, that finding is of no aid to American Fuel here, as it was based on an allegation that California had changed the way it calculated carbon intensity scores so as to "assign artificially lower CI scores to California-produced ethanol while assigning artificially higher CI scores to ethanol produced elsewhere, particularly in the Midwest." *Rocky Mountain Farmers Union*, 258 F. Supp. 3d at 1159. There is no allegation of a similar change here. Nothing in the complaint in this case suggests that Midwest ethanol's scores are "artificially" high—only that they are higher than the scores of fuels that generate lower greenhouse gas emissions.

b. In-State Benefits

American Fuel also alleges that the Program impermissibly benefits in-state entities because Oregon biofuels producers can generate credits. But, any benefits conferred on Oregon biofuels producers arise from the relatively low carbon intensity of their products. The Program assigns lower carbon intensity scores to *all* biofuels (regardless of state of origin) in comparison to other fuels because of their lower greenhouse gas emissions. *See, e.g.*, ODEQ 2016 Report; Or. Admin. R. 340-253-8030, -8040. Such factors "are not discriminatory because they reflect the reality of assessing and attempting to limit GHG emissions." *Rocky Mountain*, 730 F.3d at 1093.

And, biofuels are not a "uniquely local industry" to Oregon. *Id.* at 1100; *cf. Bacchus*, 468 U.S. at 271 (finding the effect of a tax exemption "clearly discriminatory, in that it applies only to locally produced beverages"). As the district court explained, some of the fuels "most desirable from a carbon intensity standpoint" are out-of-state biofuels. Judgment, *Am. Fuel & Petrochemical Mfrs. v. O'Keeffe*, No. 3:15-cv-00467-AA (D. Or. March 23, 2015), ECF No. 72. The Program thus does not favor in-state biofuels over similar out-of-state biofuels, which renders this case fully distinguishable from *West Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 188 (1994), upon which the dissent relies. In that case, a Massachusetts tax on in-state and out-of-state milk dealers was used to fund a subsidy exclusively for in-state milk producers. *See* 512 U.S. at 190–91. Under the structure of the Oregon Program, however, out-of-state producers are able to—and do—generate credits and thus share in the Program's benefits. As the district court noted, the Program "rewards all investment in innovative fuel production, irrespective of where that innovation occurs." *See* ODEQ 2016 Report. In contrast, the subsidies at issue in *West Lynn Creamery* were distributed explicitly and exclusively to in-state producers based on geography alone. *See* 512 U.S. at 190–91, 196–97.

Thus, the pleadings do not provide a plausible basis from which to infer that the Program will shift market shares to *in-state biofuel producers*, as opposed to biofuel producers in general. *See Exxon Corp.*, 437 U.S. at 126 (holding that a law did not discriminate against out-of-state refiners because "in-state independent dealers will have no competitive advantage over out-of-state dealers"); *Black Star Farms LLC v. Oliver*, 600 F.3d 1225, 1231–32 (9th Cir. 2010). The fact that some burdens of Oregon's program "fall[] on some interstate companies does not, by itself, establish a claim of discrimination against interstate commerce." *Exxon Corp.*, 437 U.S. at 126.[11]

c. *Pike* Analysis

"A nondiscriminatory regulation serving substantial state purposes is not invalid simply because it causes some business to shift from a predominantly out-of-state industry to a predominantly in-state industry." *Clover Leaf Creamery Co.*, 449 U.S. at 474. Such a regulation "will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits." *Pike*, 397 U.S. at 142. Although American Fuel alleges that the Program "imposes economic and administrative burdens on regulated parties" because importers of petroleum-based gasoline and diesel "must either change the composition of

[11] The fact that Oregon does not have a petroleum industry that is burdened under the Program does not support American Fuel's discrimination claims. We have previously upheld, for example, an Arizona regulation that could shift market share away from large wineries even though the state had only one large winery that would be burdened under the regulation. *See Black Star Farms*, 600 F.3d at 1227–29. The regulations show that the Program "'regulates evenhandedly' . . . without regard" to a regulated party's origin. *Clover Leaf Creamery Co.*, 449 U.S. at 471–72.

the fuel they import or purchase credits," it fails to plausibly allege that this burden is "'clearly excessive' in light of the substantial state interest" in mitigating the environmental effects of greenhouse gas emissions from transportation fuels. *Clover Leaf Creamery Co.*, 449 U.S. at 473.

B. Extraterritorial Effect

The dormant Commerce Clause also prohibits a state from regulating conduct that "takes place wholly outside of the State's borders." *Sam Francis Found. v. Christies, Inc.*, 784 F.3d 1320, 1323 (9th Cir. 2015) (en banc) (quoting *Healy v. Beer Inst*., 491 U.S. 324, 336 (1989)). American Fuel alleged that the Oregon program violates the Commerce Clause and "principles of interstate federalism" by attempting to control "commerce occurring wholly outside the boundaries" of the state. *Healy*, 491 U.S. at 336. But, these claims are squarely barred by *Rocky Mountain. See* 730 F.3d at 1101 ("Firms in any location may elect to respond to the incentives provided by the Fuel Standard if they wish to gain market share in California, but no firm must meet a particular carbon intensity standard, and no jurisdiction need adopt a particular regulatory standard for its producers to gain access to California."). Like the LCFS, the Program expressly applies only to fuels sold in, imported to, or exported from Oregon. Or. Admin. R. 340-253-0100(1).

American Fuel contends that its claim based on principles of interstate federalism raises issues not considered in *Rocky Mountain*. However, as the district court correctly noted, "irrespective of its constitutional basis, any such claim is necessarily contingent upon a finding that the Oregon program regulates and attempts to control conduct that occurs in other states." *See Rocky Mountain Farmers Union*, 2014 WL 7004725, at *13–14 (denying leave to amend on remand to add claim alleging that the LCFS was unconstitutional under principles of interstate federalism because claim was based on same premise as an extraterritorial legislation claim). Because the Program does not legislate extraterritorially, American Fuel's claim fails no matter how its constitutional claim is labelled.

C. Preemption

Finally, American Fuel alleges that the Oregon program is preempted by § 211 of the CAA. That Act recognizes that "air pollution control at its source is the primary responsibility of States and local governments," 42 U.S.C. § 7401(a)(3), but preempts state regulation of a fuel or fuel component if the EPA Administrator has declared regulation unnecessary:

> Except as otherwise provided in subparagraph (B) or (C), no State (or political subdivision thereof) may prescribe or attempt to enforce, for purposes of motor vehicle emission control, any control or prohibition respecting any characteristic or component of a fuel or fuel additive in a motor vehicle or motor vehicle engine—
>
> (i) if the Administrator has found that no control or prohibition of the characteristic or component of a fuel or fuel additive under paragraph (1) is necessary and has published his finding in the Federal Register . . . .

42 U.S.C. § 7545(c)(4)(A).

American Fuel contends that the EPA has found regulation of methane is unnecessary because it excluded methane from the definition of volatile organic compounds under § 211(k) of the CAA in light of its low reactivity. *See* 40 C.F.R. pt. 80 (1994); 42 U.S.C. § 7545(k). The CAA, however, makes plain that the administrator must find that "no control or prohibition . . . under" § 211(c) is necessary in order to effect preemption. The EPA's decision not to regulate methane under § 211(k) is not a finding that regulating methane's contributions to greenhouse gas emissions is unnecessary, and thus is not preemptive under § 211(c)(4)(A)(i).

III. Conclusion

For the reasons above, we **AFFIRM** the judgment of the district court.

N.R. SMITH, Circuit Judge, dissenting:

I cannot agree to dismiss American Fuel's claim,[1] alleging that the practical effect of Oregon's Clean Fuels Program (the "Oregon program") impermissibly favors in-state interests at the expense of out-of-state interests.

I.

Where "a statute discriminates against out-of-state entities . . . in its practical effect, it is unconstitutional unless it 'serves a legitimate local purpose, and this purpose could not be served as well by available nondiscriminatory means.'" *Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070, 1087 (9th Cir. 2013) (quoting *Maine v. Taylor*, 477 U.S. 131, 138 (1986)).

In *Rocky Mountain*, we followed the Supreme Court's decision in *West Lynn Creamery, Inc. v. Healy*, 512 U.S. 186 (1994). *See* 730 F.3d 1098–1100. There the Supreme Court struck down as "clearly unconstitutional" a facially neutral state pricing order that imposed a tax on all milk produced for consumption in Massachusetts while also providing a subsidy "exclusively to Massachusetts dairy farmers" that "entirely (indeed more than) offset" the tax for in-state producers. *W. Lynn Creamery*, 512 U.S. at 194. By increasing the competitiveness of in-state industry at the

[1] I agree with the majority that *Rocky Mountain Farmers Union v. Corey*, 730 F.3d 1070 (9th Cir. 2013), resolved many of the issues presented in this case. Nonetheless, although bound by our circuit precedent, I continue to believe that the incorporation of location and distance data into the calculation of carbon intensity values is facially discriminatory under the Supreme Court's Commerce Clause analysis. *See Rocky Mountain Farmers Union v. Corey*, 740 F.3d 507, 515–16 (9th Cir. 2014) (M. Smith dissenting from denial of rehearing en banc).

expense of out-of-state industry, Massachusetts "neutraliz[ed] advantages belonging to the place of origin." *Id.* at 196 (quoting *Baldwin v. G.A.F. Seelig, Inc.*, 294 U.S. 511, 527 (1935)). The Supreme Court explained that

> [n]ondiscriminatory measures, like the evenhanded tax at issue here, are generally upheld, in spite of any adverse effects on interstate commerce, in part because the existence of major in-state interests adversely affected is a powerful safeguard against legislative abuse. . . . However, when a nondiscriminatory tax is coupled with a subsidy to one of the groups hurt by the tax, a State's political processes can no longer be relied upon to prevent legislative abuse, because one of the in-state interests which would otherwise lobby against the tax has been mollified by the subsidy.

Id. at 200 (original alterations and internal quotation marks omitted).

In *Rocky Mountain*, we applied the West Lynn Creamery Rule in evaluating the constitutionality of California's clean fuels program (which the Oregon law models). 730 F.3d at 1098–1100. There we determined that the California law burdened more in-state industry than it benefitted. *See id.* at 1099. Importantly, that conclusion was necessary to our decision that California's law did not violate the principles in *West Lynn Creamery*. *See id.* at 1098–1100.

In its opinion the majority fails to grapple with the Oregon program's *West Lynn Creamery* problem. That decision causes them to err as is shown below.

II.

Again, to state a plausible claim for discrimination, American Fuel must allege that (A) the Oregon program discriminates against out-of-state interests in its practical effect, and (B) Oregon's legitimate interest in reducing global warming could be addressed by non-discriminatory means.

Further, as an initial matter in evaluating American Fuel's claim, this case is distinguished from *Rocky Mountain* because it comes before us on a motion to dismiss, not summary judgment. The evidentiary record has not been developed in discovery. Thus, we must take all factual allegations and reasonable inferences therefrom in the light most favorable to American Fuel. *See Adams v. U.S. Forest Serv.*, 671 F.3d 1138, 1142–43 (9th Cir. 2012).

A.

American Fuel's pleadings plausibly allege that Oregon's program discriminates in its practical effect. First, Oregon's program assigns a carbon intensity[2] to all transportation fuels produced for in-state consumption. The program then sets a maximum carbon intensity value. Fuels with a carbon intensity level above the maximum allowed carbon intensity value generate deficits and fuels with intensity levels below this value generate credits. Oregon also requires producers with deficits to off-set those deficits by purchasing credits from competing fuel producers that have generated credits under the law.

[2] The Carbon intensity value is based on a formula aimed at assessing the carbon footprint of each fuel from production through its ultimate consumption.

As American Fuel alleges, the discrimination arises from Oregon's decision to draw the maximum allowed carbon intensity value in such a manner that *all in-state* fuel producers generate credits and only out-of-state fuel producers generate deficits. As a practical matter, this not only exempts in-state entities from any burden under the law (to remedy deficits by purchasing credits from competitors), but it also affords them an additional subsidy in the form of valuable carbon credits. By contrast, out-of-state regulated entities, including American Fuel, generate deficits and experience the full impact of the law.[3]

Thus, like the tax and subsidy in *West Lynn Creamery*, Oregon's program discriminates in its practical effect. *See* 512 U.S. at 200. Out-of-state entities bear the full brunt of the law's burden, even though all fuel producers (including in-state entities) contribute to greenhouse gas emissions (and consequently global warming). At the same time, in-state entities not only avoid the burden of the law, they also receive a subsidy from the out-of-state entities in the sale of their valuable credits. Thus, American Fuel plausibly alleges that the Oregon program discriminates in its practical effect.

B.

It is also plausible that there are nondiscriminatory means of advancing Oregon's legitimate interest in combating global warming. *See Rocky Mountain*, 730 F.3d at 1087, 1106 (identifying legitimate state interests in addressing global warming). To state a plausible claim, it is

[3] As the majority is quick to note, there are some out-of-state entities that also generate credits. But the Commerce Clause problem emphasized in the *West Lynn Creamery* analysis was the uniform absence of an in-state burden—not the presence of a uniform burden on out-of-state interests. *See* 512 U.S. at 200.

unnecessary to identify every "available nondiscriminatory means" of accomplishing the goal of reducing greenhouse gases. *See id.* at 1087 (quoting *Taylor*, 477 U.S. at 138). However, it is easy to suggest one plausible example. Oregon could simply adopt a per unit tax on carbon intensity. Such a tax would discourage use of carbon intense fuels without artificially shielding in-state interests from any responsibility for their contributions to greenhouse gas emissions. The availability of nondiscriminatory means of addressing global warming plausibly establishes that the discriminatory effect of Oregon's law violates the Commerce Clause.

III.

There is no doubt American Fuel alleges a plausible claim. Taken together, the discriminatory practical effect of Oregon's program and the availability of nondiscriminatory alternatives plainly state a claim under the Commerce Clause that ought to survive a motion to dismiss.

Appendix A: Summary of Advisory Committee Input

Oregon Low Carbon Fuel Standards Report

Contents

Please note that numbering in this appendix follows the numbering in the LCFS report for consistency.

VI. Oregon LCFS Program Design

1. Summary of LCFS Program Design

November 16, 2010 Advisory Committee Meeting

- When you talk about covered fuels and then refer to the section of the report where it is defined, as an example of something we don't want to have covered now, it says ethanol derived from biomass sources such as Brazilian sugar cane, food waste, wood waste and agricultural waste, it seems like you could say purpose-grown crops or something else in there such that this list is not meant to be exhaustive. It seems like this list ought to have broader options.
- Figures 3 and 15 in report depicting the transport of LNG in or out of pipeline look incomplete to me because there will be natural gas piped possibly to California or even Washington and will trucked into Oregon, as opposed to being transported via an LNG barge. ***Response:*** *That statement is intended to say that LNG could be trucked into Oregon.* So you're assuming it gets trucked into Oregon from somewhere else in the U.S.? ***Response:*** *Right.*
- For LNG, is the fuel regulated when the barge stops and actually unloads the LNG onto a cube trailer? ***Response:*** *We haven't figured that out yet. Whoever is dispensing it, if they are getting fuel from a barge or trucked into Oregon, they would be the regulated party.* If it never gets co-mingled with the pipeline. It's unclear when you have the LNG barged or trucked into Oregon. It could be confused with the second schematic.
- There was a lot of debate around where the responsible party is if it was brought in from out of state. There was a question on jurisdiction in the example of a Boise distributor that brings a load of fuel FOB into Oregon. You're saying that the compliance obligation for that fuel will be on the Boise distributor, are you saying you've got the regulatory authority to regulate outside the state, and/or are you just going to shut down the market? ***Response:*** *Once they bring it into the state, they're responsible.* **Comment:** You're saying then that out of state parties are responsible. ***Response****: As the same way they are for the fuel tax and fuel quality standards required in Oregon.*
- In the At-A-Glance table for 2B, you have listed potential Opt-in parties as utility companies, energy service provider, or energy that goes into fuel dispensing equipment in Oregon. However, in that section of the report, it only mentions the utility companies. ***Response:*** *That is a mistake. They should read the same.* **Comment:** I also wondered if an energy service provider was essentially a fuel provider. ***Response****: In the report itself on page 55, the potential opt-in parties in Oregon are the three natural gas companies who own the majority of fueling stations, or CNG fleet owners who own fuel dispensing equipment.* **Comment:** Okay, I got thrown off where it says proposed, and then it says potential opt-in parties, and I didn't know how you were defining natural gas companies. ***Response****: It just needs clarification to indicate that anyone who owns or could own dispensing equipment could be an opt-in party.*
- How does the utility play a role in this? There are some concerns in terms of competition, because a utility can create a very uncompetitive market place, and it isn't clear if the regulation being proposed considered that, and whether it would require a utility to create shareholder subsidiaries because there is no way in a mature market that fuel providers can compete with utilities if they are able to cross-subsidize their rate base . Furthermore, for those non-participating rate payers, it doesn't seem fair why they would be paying for infrastructure. That's the issue currently being discussed with the California Utility Commission, and it is something that needs to be addressed in Oregon as well. ***Response****:*

(Wallace, ODOE) Utilities cannot sell electricity now into the transportation sector, and the PUC is the entity that regulates that. We're addressing that issue now for electric vehicles, but for CNG that has been addressed a long time ago. In fact at one point, NW Natural used to sell to the public, and they were forced to move their compressor behind the fence and cease and desist.

- For 2D (in the At-A-Glance section of the final draft report), there was something that really concerns me, particularly for utilities. The language on page 58 states that if you put biogas into the pipeline, the compliance obligation no longer falls on the producer but instead would go to the utility. ***Response****: It would go to whoever owns the fuel dispensing equipment.* The language which states that "The owner of the fuel dispensing equipment can show that the fuel was used for transportation, but the producer cannot if the fuel is injected into a natural gas pipeline." Clean Energy produces biogas from all over the country and then we pay a transfer rate to assure that those molecules can be tracked for the purpose of renewable portfolios. I would assume that the same logic that would be used for renewable electricity generation for electric vehicles, so if you assume that, this is actually inhibiting the potential for or doing production in Oregon completely because if I have no incentives to do biogas, people are going to lose that benefit immediately when the biogas goes into the pipeline. That would be a significant roadblock for us. ***Response****: Does most of the biogas going into the pipeline in California get used in the transportation sector?* Yes, because the customer is purchasing that quantity from us. They are creating the reason for us to pull that biogas from the landfill that would otherwise be wasted. So we contract that distribution with the utility. ***Response****: But in fact, what happens is the customers may or may not use that biogas, but they have paid for it to be produced.* It works just like green power for electricity. I'm paying for 10% green power, but may never actually consume that renewable power. But I am creating that market demand for the renewables to be supplied, and it's the same concept. If I'm a producer and I start biomethane projects in the state of Oregon, being pipeline accessible is an advantage because there's a line of transfer that is created so that I can actually power those vehicles that can make that case. If you take away the ability to put that biogas into the pipeline, my customer base shrinks and I can't provide those benefits. The pipeline doesn't make natural gas, it only delivers it. The actual production needed to make the fuel transportation-worthy is if you compress it or liquefy it, and that is why CNG and LNG are regulated completely different. The way the California Air Resources Board defines the regulated party as whoever has the ability to compress the gas at the station, and whoever delivers that natural gas to a transportation station is how LNG is regulated because otherwise you could put it anywhere and you'd have no idea how or if it would be used for transportation. That's why it's regulated the way it is. So if we're compressing natural gas at a station and we deliver biomethane to that station and pay for that transfer, we should be the one to get that credit, otherwise there's no reason to produce biomethane unless you're a utility and you're using the RPS. If you want it in the transportation sector, you have to make that change.
- So how would you make that happen? ***Response:*** *(WSPA) I will provide my thoughts in the written comments, but I think it would be something along the lines of the person that receives custody of the biogas in the pipeline.*
- Is the proposal for addressing fuel used in short line railroads something that has been discussed previously? ***Response****: It isn't something we have discussed as a committee. It was an issue during the authorization of House Bill 2186 and the question of how to handle fuel to be used in short line railroads was discussed in the Legislature. At this point, we don't have enough information. Real briefly, the issue with potentially using low carbon fuels in locomotives is that engine manufacturers don't warranty biofuels to be used in locomotive engines. This is an issue that may get resolved in the long run, and renewable diesel may not have that same issue, but for now we're thinking about biodiesel as not being able to be used in locomotives. And then you've got the fuel distribution network for short line railroads*

is captive in that fuel distributors are distributing primarily the short line customers, and since they can't buy any biofuels they basically have to buy 100% credits to comply with the LCFS, and we don't really know at this point how that will play. We are hopeful that the credit market will work well but when we have one small sector that is completely dependent on the credit market, we think it is premature to apply the fuel in that scenario. So what we'd like to do is by 2016 when we conduct the comprehensive program review, we'll have a lot of information about how well the credit market would work, the fuel distribution network and quantities/volumes of fuels. For perspective, we're talking about a very small percentage of transportation fuel that would otherwise be subject to the LCFS. What about the language in the rationale that says there's nothing in the LCFS that would prohibit regulated parties from obtaining unblended fuels, and that was included to address harborcraft, how is that any different for the locomotive operators? Why should DEQ be exempting anything that was not specifically mentioned in the legislation? ***Response****: For the other markets, the fuels distributors will be able to meet most of their compliance obligation by blending biofuels. They may have some customers that won't be able to use their product and will have to buy credits to cover that portion, we think in this case it may be that their primary or sole customer can't use biofuels, and they essentially have to purchase electric vehicle credits for 100% of their compliance obligation, which we think is premature before seeing how the market will work, so it's a very unique circumstance. And the harborcraft people haven't argued this same point? Response: We haven't heard from them that they have the same fuel distribution problem*

- I recognize the unique character of that small market share, but am sensitive to the fact that for many years there has been, albeit anecdotal, and not standard testing of a number of short lines that have blended biofuels and have we heard mixed stories about an unsatisfactory experience. It's not just the engines, but I understand its' also retrofits and associated warranties. Most of their fleets are somewhat legacy blends, but parts are still an issue. ***Response****: Hopefully one way or another, this issue will get resolved by the mid-program review, and there are a lot of reasons to wait and observe for now.*
- My concern with choosing a number (360,000 gallon threshold for fuels used for transportation in small volumes) we are inadvertently discouraging pilot and demonstration plants from locating in Oregon, and that is a very important stepping stone to commercial scale for new fuels. ZeaChem's plant is going to have a capacity of 250,000 gallons per year, and so I think at that scale it's still in the experimental phase, it's not commercial scale, and I think it would be preferable to have an opt-in status depending on how well the plant is running. I don't know where they would fit in the proposed exemptions. Obviously they are above the 50,000 gallon threshold, but they may be under 360,000 gallons but I'm not sure if that would apply to them. And the other issue I see is what if you get imported fuel from out of state that are outside of the categories, and how then do you define the category. You may be creating a disincentive to begin their development process. I would recommend a clarification of the 360K and what that applies to and how that gets parsed out. ***Response****: I'm not sure I understand how the 360K threshold might create a disincentive.* What you've got is a capacity, but under a demonstration scale you're really running campaigns. You're building a capacity but it's an experimental facility and under those circumstances, you aren't necessarily going to be hitting your pathway CI numbers, it's going to be really irregular. And so if you were in a position to take advantage of being a regulated party, you would want to do so. ***Response****: It almost sounds like we need another exemption for a pilot facility that could apply for pilot status if they were not in commercial operation.* ***Response****: (Chair) This also has to square with how we deal with new fuel pathways. Are you talking about a new pathway, or just making the same product the same way or a different pathway? Because with a different way, don't you have already some threshold?* ***Response****: We do, but I think what Harrison is saying is that if a company is still working on their process and wants to pilot a demonstration scale, they want to avoid all of that.* I'm saying that we would want the ability to opt-in to take advantage of it. You want the credits and want to be in the game, but it's very likely that you will not be in the game until you've refined your process.

***Response**: So what about an option for an individual small scale producer that produces greater than 50,000 gallons that is in pilot mode can apply for an exemption? They'd have to declare themselves to be a pilot facility and it seems like it would make sense if we had something like that. Does anyone have any objection to that concept, of having an opt-in option? There would have to be some demonstration that it was a pilot operation.* One distinction would be that the facility is demonstration or piloting a new technology, not one that already exists. (Chair) There probably also ought to be a time limit on it because the program overall wants to put all the low carbon producers in to the program so that credits can be available for use. ***Response**: (ZeaChem) But they don't get the benefit, and you'd want to seek that benefit when you are capable of doing so, and I think this can be set up appropriately to achieve that. I think a demo may remain a demo, and then you shut it down once you've built a fifty million gallon plant at that site or nearby.*

- Haveo you determined whether those facilities exist***Response**: Not that I know of, but it could happen in the future.* For those who are contemplating import of low carbon fuels in Southern California, it is really confusing to figure out what stations actually receive the molecules of biogas that are put into the pipeline and at what volumes. There will be times when a facility won't import, and it's really up to a utility with regard to how they purchase their gas.
- What about facilities that would eliminate truck stop idlingwould that fall under this exemption? ***Response**: I think it depends on who owns the equipment.*
- It seems a little inconsistent with CNG and electricity, because for CNG the proposal before us, if someone wants to put biogas into the pipeline it gets tracked the same way as green electric power. For example, when electricity derived from solar or wind power gets sold, the customers know what they're buying, but the exact electrons that they receive aren't going to all be generated from green sources. But there's a contract in place for that particular commodity and we can track where it goes.
- So is your suggestion that we use similar language that has to do with the chain of custody being documented by the dispenser? ***Response**: (ODOE) Yes.* ***Response**: The purpose of this program is not to reduce the carbon intensity of electricity production but it intended to reduce the carbon intensity of transportation fuels. There are other programs such as the Renewable Portfolio Standard and other ways of affecting the carbon intensity of electricity itself. What we're trying to do with electricity is capture what its carbon intensity is as a factor in calculating the carbon intensity of electric vehicles but not trying for implements that account for it, unlike the biofuels which are being produced specifically as transportation fuels.* ***Response**: (ODOE) My concern is that it is not consistent with some of the other efforts being made in Oregon to reduce greenhouse gas emissions, like Senate Bill 1059, which tracks on a county by county basis and looks at the utility aggregated mix of that county. Those numbers are drastically different than what is being proposed here and ODOE is looking at the transportation sector of a utility different than the residential, industrial and commercial sectors, so it's all pulled apart. You're looking at it as if it's part of the overall field and it's not. Nor will it be counted that way, because the transportation sector is going to be looked at separately.*
- This is too small a market to affect a change in the decision making processes of utility companies, so the question then becomes, can you put the burden on individual entities or users to prove through chain of custody that they've done something exceptional so that there is an outlet for that but the burden isn't on DEQ. There should be a process that utilities can go through to show that they've done something to distinguish the carbon intensity of the electricity they generate. ***Response**: The purpose of this program is not focused on community comparisons.* ***Response**: (ODOE) There's a statewide program for 2011 that SB1059 came out of, but we still have the statewide analysis to conduct. SB1059 was a separate mandate for Metropolitan Planning Organizations.* I don't see what the distinction is for biomethane and other renewables. Biomethane can be sued for power generation or transportation, and if you try to identify

where the renewables are coming from, you run the risk of double counting which diminishes the ability of the program to create real carbon reductions. It would take away incentives for an industry to move in that direction. ***Response:*** *Those are valid points. The other side of that is if you are purchasing an electric vehicle, the benefit that would come from that electric vehicle would solely depend on where you live because you don't have control over your service provider district and what choices are made in terms of renewables there.* I'm not sure that accurate, because I could produce biomethane and power a fleet of transit buses in Portland for example, and they could use that biogas. ***Response****: In the electricity sector though, the question is does the role of electric, which is predominately from the Bonneville hydroelectric source which is very low carbon intensity as compared to the Pacificorp and PGE service territories, and that is where the population centers are located that can most likely support electric vehicle infrastructure. So you've got a mismatch where the likely market is for electric vehicles compared to where the low carbon electricity is generated, so we'd be creating a system that would not likely create the right incentives for getting electric vehicles infrastructure. Beyond the timeframe of the LCFS, those electric vehicles will still be generating carbon reduction benefits for a long time. There's no right or wrong answer to this issue, but the net result is that the statewide average electricity carbon intensity then makes that all neutral with regard to the incentive for putting electric vehicle infrastructure in place.* I have no problem with a statewide application I'm just surprised that there would be no incentive for low carbon fuels in a low carbon fuel regulation.

- If you go back and adjust the value of banked credits, it's going to put a lot of companies out of compliance, ***Response****: The concept is that if we add indirect land use at some point in the future, some of those low carbon credits will have less value and the baseline would be off if we didn't adjust it, and any banked credits would be overstated. So this wouldn't affect a past compliance determination, but the use of those banked credits in a future year needs to be put on par with newly generated credits.* What would happen to a regulated party that is just barely in compliance at that point in time? Would you re-adjust the baseline before they are out of compliance so they don't have excess credits that then need to be adjusted? ***Response****: Adjusting the baseline doesn't affect their compliance, it affects how far we have to go to get the ten percent reduction. So what we'd be doing is calculating what the carbon intensity at the start and end of the program is and getting a ten percent reduction. I don't think it affects an individual company's compliance unless they were relying on those banked credits for next year's compliance obligation. If, as a result of the mid-program review DEQ decided to add an indirect land use change value to the carbon intensity of a fuel, regulated parties will know a couple of years in advance that that change is coming and there will be some established amount of time before it goes into effect. If the assumption was that the very next year regulated parties would be able to use those credits the following year but they couldn't, then that would be a shock to the system. But you can't allow the banked credits to be overvalued compared to the newly generated credits.* Starting with a number to represent indirect land use change like CARB is using and then adjusting that number at a later date as more accurate information becomes available would result in a smaller adjustment to those banked credits. Indirect land use needs to be included. What numbers should be sued I am not prepared to take a position on at this time, but there is enough out there that says indirect land use should be a component considered in the LCFS analysis. ***Response****: This is probably another one of those cases where there isn't a right or wrong answer, and DEQ encourages committee members to articulate their position in the exit survey. We realize there is not consensus on this issue within the committee, and we took the various positions into account when making this proposal.* They way I read and understand DEQ's position is that there isn't enough certainty behind the indirect land use change numbers and it's essentially a wait and see approach, and once there's enough confidence to move forward they would take action. I thought WSPA would be supportive of DEQ's approach, because I took it as if a fuel producer has any question with regard to my CI reduction associated with my fuel when I'm generating credits I may not want to bank them but instead I may just want to sell them because I don't know if those credits will hold their value. The problem I have with this proposal is that the people who sell the credits don't get dinged, the people who bank credits do. And a regulated party who is counting on those banked credits to help comply with the standard in the later years of the program gets screwed because the game has changed midway through. I think you have some unintended consequences with 8A (At-A-Glance) because it's not only not fair across the board, you're going to have a dumping spree of banked credits by those who think they might be at all in jeopardy of losing monetary value of those banked credits. If you want to avoid having to go back and re-calculate emission reduction credit values, you should also change the value of any credit that is generated from that decided date that the change takes effect moving forward. If my strategy is to bank generated credits for future years I get penalized because I may be more efficient and I don't need those credits, so that's a raw deal. ***Response****: The ideal scenario for the present is that we would have great science that would tell us what the land use change numbers should be and we'd do it from the beginning. But currently, the state of the science isn't there yet and in we also have a lot of questions about other indirect affects and whether biofuels are being unfairly penalized by an indirect affect and the divergence in the numbers of land use are so wide, the safe bet is to go with the cellulosic ethanol and what we're saying is that we not going to take corn ethanol and add an indirect land use change number to it at this point but stakeholders are on fair notice that those credits may be worth less in the future as the science determines what those numbers should be. So it wouldn't be of great benefit to bank a bunch of ethanol credits for long term as this policy approaches. But if we went with the approach you are suggesting and provided a protection for credits banked under certain set of rules and you should be allowed to keep them at the value they had when generated, the problem is if we have a large volume of banked credits, that's going to dis-incent future production of low carbon fuels. We're trying to balance the whole scenario.* I'd say include CARB's values for indirect land use change right now. You're saying DEQ won't start regulating until the Department feels like there is enough certainty as to which numbers should be used and sorry to those who banked their credits, you lose and the people who sold them win, and I don't think that's fair at all. I think that will create a high carbon flood in the market system, and they will take as many credits as they can and then we'll see a large exodus of those high carbon fuel producers from the LCFS program. ***Response****: Let's have everyone clearly state their position on this issue in their exit surveys and in your comments on the report as well and we can give this some more serious thought.*

- The EER figure being proposed for heavy duty CNG and LNG is a California-specific EER which accounts for the legacy vehicles on the roads today, so this is not what is expected for future vehicles. I would encourage DEQ to contact Cummins Westport and other manufactures for a more accurate EER value for those types of vehicles because this is not accurate.
- There was discussion earlier about adopting the California LCFS reporting system and this is quite contrary to that system, so it will require a lot of programming modifications and guidance development. So I would challenge the assumption that Oregon could use California's system without making significant modifications to it. An Oregon-specific program will require additional resources to build and implement.
- In California, credits cant' be used until the following year so that they can be verified by CARB. ***Response****: The regulated parties will be responsible for calculating the value of credits generated and reporting that information to DEQ. DEQ will not be going out and verifying all these credit transactions. We may spot check some, but the essence of the annual report is to show that you credits and deficits match and that you bought credits from somebody who reported to us that they generated credits. The regulated parties will have to be buying and selling credits that they know are valid. DEQ will not be*

certifying credits ever, even at the end of the year. DEQ will check the reports and make sure the credit transactions balance, but I don't see what the hold up of buying real time credits would be.

- Would all fuel providers have to register with the state? ***Response**: They would anyway . They are already automatically a regulated party, so if you think you're buying credits from an opt-in, you'd want to verify that they've opted in and that would be your due diligence as a buyer that you aren't buying more credits than they produced but otherwise you don't know if they've already sold their credits to somebody else.*
- The temporary deferrals are looking at two components. Some of the deferrals are looking at supply issues while the other is looking at cost issues to the consumer, but those two things are intertwined and under the Type 1 description where the regulated party is still having to comply, I can envision a scenario where regulated parties would continue on no matter what the costs just to be able to be in compliance and not have that compliance burden hanging over them. A regulated party is going to want to be in compliance and cost is a secondary factor versus the supply question. ***Response**: Even though they would still be in compliance carrying over?* But they wouldn't be, they would have a continuous increase of that obligation and I see that as potentially complicating because I see both components as one issue. A supply problem may happen, but you won't have the 12-month rolling price average to address that for a year, so you'll have a huge cost impact immediately. ***Response**: Type 1 was designed for a small debt that is over five percent and not likely to affect the price, and regulated parties will have to decide whether to buy credits now or decide to allow a deficit to accrue under the assumption that credits will be cheaper next year, but that is only an option when the deficit is small and doesn't have the potential to affect the price. If it's a large deficit under Type 2, it will be forgiven during the deferral period. In balance there is not going too far on either side with Type 1 or 2 because under Type 2 you're losing the benefit of the program during a deferral period and you're allowing credits to continue accruing so you aren't dinging biofuels producers but you're still diluting the program so you aren't getting any benefit from the program this year and you're also allowing banked credits to accumulate you're going to get less benefits next year so it's something you'd only want to do if it's a large long-term disruption in supply.* (Chair) The term "available" is used, and obviously price does matter because more things are available if you're willing to pay more. Do we have some threshold or significance to determine what is "available"? ***Response**: Not really. If there is a fuel that is being delivered to Oregon the previous year I would say that that fuel is available.* ***Response**: We can address that in the guidance that accompanies the rule, but we don't have that figured out at this point.* Also, there is a proposal on the table by DEQ to identify when a deferral is triggered, but we still don't know what the deferral means. ***Response**: For this one specifically or for all of them?* For this one specifically, you're identified the 0.01% trigger, but haven't articulated how the program would be affected. ***Response**: There are two proposed ways to address that type of scenario. The first is to administratively defer the LCFS for a week to a year and the second is to go through a rulemaking to adjust the compliance schedule end year. If it gets deferred for a year the standard would go right back to where it would have been the next year.*
- We may want to change the terminology that currently reads "Initial physical pathway report" in the reporting section to distinguish the physical route a fuel is transported on from the pathways associated with assigning a carbon intensity value to a fuel type.
- Correct me if I'm wrong, but I thought the concept was that the physical pathway was to document that you qualified for a specific lookup value on the table so it's not just new fuels. ***Response**: (Chair) So if that is the case, basically all reporters would have to do something at least once.* ***Response**: That is correct. It's a one-time report for each fuel from each company until a change occurred that would affect the carbon intensity of a fuel type, at which point they would be required to submit a new report.*

- If regulated parties were able to roll up all the identical pathways and report one number at the end of the year that's one thing, but if they were required to report each transaction that would be very burdensome. ***Response****: We welcome comments and suggestions on how to do this differently, because we only want to collect the data that will help us determine whether a regulated party is in compliance and no more.*
- If regulated parties were able to roll up all the identical pathways and report one number at the end of the year that's one thing, but if they were required to report each transaction that would be very burdensome. ***Response****: We welcome comments and suggestions on how to do this differently, because we only want to collect the data that will help us determine whether a regulated party is in compliance and no more.*
- With regard to meeting compliance obligations, do you need anything in the way of enforcement that says failure to submit a required report is a Class 1, 2 or 3 violation? ***Response****: Let me briefly explain DEQ's enforcement rules. There are several things that happen in Division 12. One is we classify all violations as either Class 1, 2, or 3, with Class 1 being the most serious violations like a violation of a standard. A Class 2 violation would typically be recordkeeping violation, and this is the default class that all violations fall into unless otherwise specified. There are penalty matrices, and the penalty for a Class 1 violation by a large business is bigger than a penalty for a Class 3 violation by a home owner, for example. So you have to identify which penalty matrix is appropriate for the violation based upon the classification. If those things aren't identified it all defaults to a moderate level so the program rules would work without any specific changes, but we do want to differentiate between the more serious violations like not complying with the standard against a more minor violation like failure to submit a report on time. Since the first two years of the program will be reporting only there wouldn't be any major violations during that time, and any reporting violations would default to the Class 2 violation category.*
- Is there an educational component? Will it be that a regulated party could receive a Class 2 violation before being trained on how to comply? ***Response****: Beyond the initial reporting years of the program, once the rules are defined in terms of classifying violations, then there is our existing enforcement guidance about how we respond. So if an inspector discovers a violation, and it's the first violation and the violating party is cooperative and correct the violation immediately then they get a warning letter versus something else where it's a repeat violation and the violating party doesn't cooperate, the violating party in that case would not get a warning letter but would instead receive a referral for enforcement.*
- In terms of funding mechanisms for the program, why not don't we a discussion about a funding mechanism? ***Response****: When House Bill 2186 was authorized it did not come with funding, and DEQ let the Legislature know that we could use in-house resources to develop the program, but that the Department wouldn't be able to implement the program without additional resources. Right now when you look at the schedule the initial program implementation is reporting so the resource needed primarily is resources to develop the database to receive reports and conduct outreach, and we're fairly hopeful that a combination of federal funding and in-house resources will be able to handle that. So the significant part of the budget requested would be when the compliance obligation begins in 2014, and we will have to have a budget request to go along with it. We will be discussing this with the Legislature this session, but it will not be presented as a budget request in 2011. It would probably be a budget request in the 2013 session, but remember there is currently a program sunset in 2015 so that issue will have to be addressed in 2013 along with other questions still remaining at that time with regard to the path forward.*
- And that could be a fee-based funding model? ***Response****: Whether it was general fund or a fee-based method, it would still have to go before the Legislature. We haven't investigated that at all, but we anticipate that if California has 40 FTE to implement their LCFS program, just on the back of the*

envelope, Oregon is about one tenth the size of California, and we will be heavily riding on their program for ideas on how to implement the Oregon LCFS, we will probably need 2 or 3 FTE to run this program, but have not yet conducted a detailed analysis. In the 2011 Legislative session, DEQ will not be taking any position on whether the sunset should be repealed or not, but as part of the report, we will identify what the potential impacts of the sunset are and it will be informational at this point.

- As part of the rulemaking process, DEQ must submit to the Legislature a Fiscal Impact Analysis. Does that Fiscal Impact Analysis include any estimate in terms of need for staff? Can you do that in the absence of any authorization for staff? ***Response****: Yes.* Is that typical? ***Response****: The thing that's not typical about this program is that it's got a phased and very delayed compliance element to it. So typically when we're adopting a rule it's got a fiscal and economic impact that we can identify, and this might be a little more speculative. But with the requirement in the Oregon Administrative Procedures Act, we need to disclose all the information that we have, and so we can provide what we know, but not what the fiscal impact is going to be.*
- I'd like to take this opportunity to say publicly that I thought this format was masterful in terms of laying out and laying everyone know what you heard, and that you made your decision. ***Response****: Thank you for that, and we're hoping that sine we knew going into this committee that there would be a wide divergence of viewpoints we didn't want to ask you to sing a report that says this is our committee recommendation. We are trying to be very clear that this is DEQ's recommendation informed by these discussions. Hopefully most of you agree with many or most of the recommendations even if you don't like the program as a whole. And we've said all along that if there are some of you who don't think that we should adopt it at all will have an opportunity to weigh in on that once the rulemaking process starts, but we were focusing this committee on what would be the best way to implement the program. We really appreciate the effort and time you all have spent on this committee. It has been really helpful and a great learning experience.*
- For the clarify the toxics reduced by biodiesel, can you elaborate on that? ***Response****: The PM from diesel is considered a toxic air pollutant.* CARB doesn't recognize any toxics reductions unless it's created in E20. ***Response****: the take home message from this is that we don't know where we stand yet with the anticipated revisions to the ozone standard and will hopefully know more with regard to any areas in Oregon that might be violating it by the end of this year. If we are violating the ozone standard, transportation is a significant source of precursor emissions for ozone and ethanol can increase the VOC emissions and biodiesel could increase the* NO_x *emissions, both of which could make it harder to meet the ozone standard, and depending on how much of those fuels are used we may have to offset that in other ways in out ozone strategy. So balancing all the environmental affects we definitely need to be aware that the low carbon fuel standard could work against the ozone standard but the effect of that may range from very marginal or nothing to significant.*

Summary of written comments from advisory committee member or alternate November 29, 2010

- 3B - Farm vehicle and logging trucks - a strange request given that these two industries stand to benefit the most from alternative fuels as feedstock providers. What conditions do they have that are different from others other than cold weather. Blending for cold weather is an important concer to address.
- Short line rail should not be exempt. The switch to cleaner fuels is a one time inconvenience. Short line rail systems consume a very large portion of a metro areas fuel and therefore a very large portion of the local and global emissions. While cold weather lines will need to vary their concentrations of some fuels in the cold months, much of the concerns come from improper protocols when people aren't informed on the transition methods. A one time education effort should not be a barrier to adoption.

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- 5 - Post 2022 should be a lot more aggressive in the reduction schedules. While we MUST allow for a real technology and infrastructure change, the emission reductions that mean the most are the reductions that happen sooner than later.
- 6a - EXCEPTION: An electricity provider who only provides electricity for transportation and is exempt from Oregon Public Utility Regulation by ORS 757.005 (1)(b)(G) can obtain a carbon intensity number that is different than the statewide average carbon intensity for electricity and specific to the electricity they supply. - Change the word "supply" to "dedicate or purchase for the purpose of meeting the EV load." "Supply" is too nebulous.
- 6B - Need to put something here that ensures that if the carbon emission reductions of the co-products are attributed to the fuel CI, then there is no other way that they can market those reductions in the channels for the co-products.
- 6C- Careful to align this with DEQ's definition of waste versus beneficial use. For compliance with the RPS it must be defined as waste. Mill waste and post consumer organics/wood are excellent beneficial use inputs. If they are categorized as waste, it may require a fuel producer to unnecessarily cary a solid waste permit.
- 6d - This assumption is fine given no timescale. Consider that bio sources that grow on a yearly basis are very different than trees on a 40 year plus cycle. The environmental community will fight any process that allows for large biomass that is on a long cycle. This section should be re-written to accomodate short life biomass and waste biomass only. This will alleviate the concern about "whole logs" as feedstock to energy and fuels and addresses the timescale concerns of a true living carbon cycle.
- 6E - Next cycle of this platform should include an Energy returned on Energy invested ratio. We can't afford to waste our energy in the name of lowered emissions.
- 6F - Should state that DEQ intends to implement a carbon intensity factor for land use in 2014. Otherwise it leaves it open for more delay.
- 6G - if we are considering or implementing indirect land use in 2014, we simply MUST pair this with other indirect effects. Otherwise we are incenting one fuel pathway over another.
- 7B and 7c are good ideas that will allow for the rapid change in technology and industry.
- 8 - Stipulate that dedicated electricity can not be zero carbon through offsets. It must be sourced from Renewable sources - reference those power sources that are zero carbon in production and insist on bundled recs. Buying NWPP power and matching recs does not reduce carbon. Recs do not equal negative carbon, just null carbon so adding them to NWPP power still equals the carbon intensity of the power pool.
- 9A & B - Note that this is VERY different then fuel *supply* disruptions.
- What do we do if the deficits are greater than what the credit holders want to sell? It seems that the only way to meet the compliance bar will be to import very large volumes of ethanol etc from low carbon fuel sources in other countries. While the CI may be known, it may encourage other ecological or social harm to those areas that are not regulated the way they are in Oregon. Likely the deferrals will build up for three years. Then the market will be flooded by imports for a brief moment and then go back to normal.
- This will not support innovation in our region. This problem will go away when the production volumes of LCFs catches up to the high carbon intensity fuels. Perhaps we should:
- Build in a preference for in state produced fuels somehow.

- Allow trading between states? We could also consider a price cap on credits that would take away the incentive to horde credits and make it mandatory that Oregon generated credits are purchased first. This would de-facto set the market price.
- 10A - this threshold is awfully low. It seems like this is well within market fluctuations.
- 11A - 5% is too low. The price of fuel fluctuates a lot. We can't interfere with the incentive to use less fuel.
- 11B - Exempting a fuel type is a bad idea. Letting deficits accrue is more appropriate.

Summary of written comments from advisory committee member or alternate November 30, 2010

- 2f) Electricity opt-in period should extend beyond 1-year.
- 4) Fully support two baselines—1 for gasoline, 1 for diesel
    - Promotion of low-carbon fuels derives the largest economic benefits for Oregon. Simply substituting diesel for gasoline based on vehicle technology improvements does not yield as many benefits. Oregon needs to develop clean alternatives to petroleum, especially as petroleum will grow increasingly carbon-intensive in the future.
- 5) DEQ should make every effort not to let the compliance schedule slip. Every year that we delay implementation of the program is a year delay in investment opportunities and carbon reductions for Oregon.
- 6a) Carbon Intensities
    - We support the exception for transportation-only electricity suppliers.
    - We support reviewing a statewide average for electricity during the 2016 program review.
- 6h) DEQ should reassess EERs to allow for technology improvements in all vehicle types. The way this is currently written seems to imply there will only be improvements in ICEs, where as efficiency improvements will likely be made in EVs and other engine types.
- 7c) DEQ needs a better method of tracking high carbon crude. This is important for the smooth administration of the program so that low-carbon fuel producers know how large the market will be from year to year, and for the environmental integrity and efficacy of the program. This distinction is very important and has severe environmental risks attached.
    - Reports suggest that tar sand production is poised to ramp up quickly. DEQ needs to closely track these developments.
- 10) Forecasted fuel supply deferral: A 0.1% threshold is too small. At this level, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5% confidence interval, so this number should be at, or just outside that range. This section also needs to allow for the 10% carry over to be factored in.
- 10b) Compliance adjustments: Whenever possible, DEQ should make up for reductions lost in deferrals.
    - Allows bigger market for L-C fuels.
    - Better environmental outcomes.

Summary of written comments from advisory committee member or alternate December 1, 2010

- 2f) DEQ needs to finesse this recommendation. Because there are multiple potential opt-in parties for electricity, there needs to be a way to cycle through so that each party has an opportunity to participate in the program. However, after that time has expired, there should be an opportunity for any party to decide at any point to participate in the program. Time limitations don't apply for other fuel types, so electricity should not be limited by a one-year opt-in period.

- 4) OEC fully supports using two baselines—one for gasoline and one for diesel.
  - Promotion of low-carbon fuels derives the largest economic benefits for Oregon. A single baseline would reward a simple substitution of diesel for gasoline—based on vehicle technology improvements, rather than fuel improvements—and does not yield as many benefits. Indeed, the economic analysis did not show any advantage for a single baseline strategy. Oregon needs to develop clean alternatives to petroleum, especially as petroleum will grow increasingly expensive and carbon-intensive in the future.
- 5) DEQ should make every effort not to let the compliance schedule slip. Every year that we delay implementation of the program is a year delay in investment opportunities and carbon reductions for Oregon.
- 6a) Carbon Intensities:
  - We support the exception for transportation-only electricity suppliers.
  - We support reviewing a statewide average for electricity during the 2016 program review.
- 6f, g) Indirect Effects: OEC supports inclusion of indirect effects within the timeframe proposed by DEQ. Indirect effects are real and are important for accurate carbon accounting.
- 6h) DEQ should reassess EERs to allow for technology improvements in all vehicle types. The way this is currently written seems to imply there will only be improvements in internal combustion engines, where as efficiency improvements also will likely be made in electric vehicles and other engine types.
- 7b) DEQ needs to allow for a pilot-scale category that does not automatically regulate facilities at this scale, but does allow an opportunity to opt-in.
- 7c) DEQ needs a better method of tracking fuel sourced from high-carbon crudes. This is important for the smooth administration of the program so that low-carbon fuel producers know how large the market will be from year to year, and for the environmental integrity and efficacy of the program.
  - Reports suggest that tar sand production is poised to ramp up quickly. DEQ needs to closely track these developments.
- 10) Forecasted fuel supply deferral: A 0.1% threshold is too small. At this level, the program will constantly be assessed for deferrals. Forecasts are usually predicted within a 5% confidence interval, so this number should be at, or just outside that range. This section also needs to allow for the 10% carry over to be factored in.
- 10b) Compliance adjustments: Whenever possible, DEQ should make up for reductions lost in deferrals. This will create a more predictable market for low-carbon fuels and yield much better environmental outcomes.
- 13) OEC encourages DEQ to develop LCFS-specific enforcement actions as soon as possible and to maintain strong oversight of the program.

2. Covered Fuels

December 3, 2009 Advisory Committee Meeting

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- Best option depends on how the program deals with credits. If the program does not have credits, Options A (electricity, hydrogen, LNG from biogas and CNG from N. American sources are opt-in, all other fuels are regulated) and Option C (same as A, except that biofuels plants could opt-out) would be fine. If the program uses credits, then Option B (all fuels are regulated) looks best in order to ensure that credits are available to buy under the program. ***Response****: An advantage of Option B is that information would be available about the supply of low carbon fuels because producers of low carbon fuels would be required to report. However, they would not be required to sell credits.*
- Whether opt-in parties decide to actually opt-in to the program depends on whether the trading mechanism is user-friendly, especially in the case of individuals owning electric vehicles. ***Response****: It seems unlikely that low carbon fuel providers will choose not participate, because reporting costs will be outweighed by gains from selling credits. It is important to give incentives for participation, both to ensure credits are available and to lay the groundwork for low carbon fuel availability after 2020.*
- Even if entities decide to opt-out, they will be subject to the LCFS as consumers of fuel.
- PacifiCorp prefers the opt-in approach. Their service area is largely rural, meaning that the costs of installing separate meters and gathering the data will initially outweigh the benefits of selling credits.
- Publicly owned utilities find it difficult to take a position at this time without knowing more details, but have concerns about lack of resources for investments and load growth.
- Perhaps charging stations could split credits with owners of vehicles, using a something similar to the cardlock system. ***Response*** *(PacifiCorps representative): In the short-term, it would be more efficient for the utilities to perform the function of accounting for and trading credits on electric vehicle owners' behalf, but in the long-term a liquid market may be developed that will make it easy for individuals owning charging stations to trade credits on their own. If utilities are forgoing an opportunity to generate revenues, people will bring it to the attention of the PUC.*
- The gradual phase-in schedule for LCFS argues for an opt-in approach.
- Biomass-based diesel has such low carbon intensities that it should be an opt-in fuel. ***Response*** *(CARB): They included it among regulated fuels because credits from biomass-based diesel are needed for compliance with the LCFS.*
- Many advisory committee members felt that Option A (electricity, hydrogen, LNG from biogas and CNG from N. American sources are opt-in, all other fuels are regulated) would work, with some reservations about whether biomass-based diesel should be included in the "Regulated" group or the "Opt-in" group. ***Response****: This determination will partly depend upon the ultimate carbon intensity numbers for biomass-based diesels.* A discussion ensued about whether participation of biomass-based fuels should be mandatory, with concerns raised that small producers could face reporting costs without a countervailing opportunity to sell credits. ***Response*** *(CARB): California allows an exemption for low volume fuel producers, because the reporting costs could outweigh the opportunities for some of them. However, they did not find most biomass-based diesels to fit into this category because they are not small volume.*

Summary of written comments from advisory committee member or alternate December 1, 2010

- Clean Energy believes it is the intent of the DEQ only to regulate liquefied natural gas (LNG) that is imported from overseas to the United States and not blended with otherwise North American natural gas contained in the country's pipeline system (i.e., LNG would be subject to regulation if it is trucked directly to a vehicle refueling station from an LNG import terminal). Clean Energy does not believe this is made clear in the "At A Glance" summary and section describing "lb)". We therefore recommend that

DEQ adopt the following language for fuels "Regulated (compulsory participants) under LCFS": "Fossil LNG that is imported from overseas and trucked directly to a vehicle fueling station without the benefit of blending with North American-based fossil natural gas within the country's pipeline system." We believe the above definition would provide a better understanding of DEQ's true intent under this section.

- Clean Energy supports DEQ's decision to limit the regulation of Fossil LNG to imported LNG that is not blended with North American fossil natural gas within the country's pipeline system as we believe the blending of imported and domestic fossil natural gas will still provide a fuel that will meet, if not exceed, the LCFS' 2022 carbon reduction goals. In fact, North America's abundance of natural gas due to the advances of hydraulic fracturing calls into serious question the economics behind the future importation of natural gas from overseas. Even if LNG is brought overseas and injected into the pipeline, Clean Energy believes such injections will be limited and represent a small fraction of the natural gas supplied to the state of Oregon.

3. Regulated and Opt-in Parties

January 27, 2010 Advisory Committee Meeting

- CNG is a currently-existing technology, useful for short “captive” fleets that travel short distances, but economically marginal at this time. The LCFS could tip the scales in favor of making it economically feasible.
- Natural gas utilities are considering ideas to make home compressors more widespread, like leasing them to homeowners.
- Natural gas world has changed drastically over the last 12 months, with many new discoveries. Heavy-duty vehicle fleet owners are especially interested.
- Most common use of LNG is forklifts. They would most likely liquefy pipeline gas onsite. LNG gives vehicles more range.
- California’s LNG filling stations were developed as a network for long-range trucking fleets, tied to the port of Los Angeles. The effort was led by a California clean air agency.
- The equipment is the same as for fossil fuel natural gas, although there could be extra steps to clean it to ensure there are no equipment problems. It’s more difficult to clean methane that comes from municipal solid waste and sewage, compared to dairy manure. Most of this methane is used for electricity generation now. The LCFS could tip the scales in favor of making these kinds of projects more feasible.
- What is included when calculating the carbon intensity of methane from waste? Where are the boundaries drawn?
- Is there an easy way of netting out fuels that come to a Portland terminal, and then are barged to Pasco? ***Response*** *(Trucking Association representative):* State economist has a study of fuels bought and used in Oregon and Washington. Perhaps the designation of regulated parties can piggyback onto the fuel tax system. Commenter believes that out-of-state distributors selling fuel into Oregon pay Oregon fuel tax. ***Response:*** DEQ LCFS team will coordinate with current greenhouse gas reporting rulemaking team to try to make reporting for LCFS and GHGs coincide where possible.
- How it would be handled if a distributor has retail stations on either side of the state borders? ***Response:*** If Washington and Oregon have similar programs, then we can coordinate.

- Does this proposal track with federal "Blenders of Record" designation? ***Response** (WSPA):* "Blender of record" refers to producer. For EPA reporting purposes, the refinery reports. That is the level where WSPA prefers reporting to be.
- In case of a retail station getting shipments from out of state, the retail station would be a regulated party? ***Response:*** This issue has come up for GHG reporting as well. The volume of fuel involved is very small, but some fuel does arrive in Oregon this way. We want to try to make this as simple as possible for small businesses – perhaps an out-of-state distributor could voluntarily agree to be the regulated party in order to make it easier for the Oregon gas stations they distribute to.
- Where the biofuel producer is selling to a terminal, it seems likely that the compliance obligation would shift to the terminal, but that the terminal would pay a premium for the biofuel depending on its carbon intensity in order to get the credits. ***Response:*** This is correct. However, the biofuel producer would still need to report.
- Why is non-North American natural gas treated differently? ***Response:*** We know that North American natural gas has a low carbon footprint, but non-North American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.
- It's possible that someone could deal in LNG, trucking it around to sell as a fuel. Or a fleet owner could liquefy it themselves. In any event, the volumes are likely to be small.

February 24, 2010 Advisory Committee Meeting

- There are some practical implementation issues there. Opt in versus regulated? If the regulated entity is always going to be a fuel dispenser, then the fuel dispenser might be a fleet operator. How is he going to know if he is opting in or if he is already regulated, because the portion of the natural gas that he gets from the utility will not go to any of the dispenser, so they are not regulated, but they are the ones that are coordinating the LNG. So is anybody going to do natural gas just by virtue of the fact that LNG makes its way into the natural gas distribution system that just happens to be a customer. Because if the regulating is the fuel dispenser you won't ever have an opt in. If you want to sell natural gas to transportation because there is LNG in the mix already, aren't you then already automatically regulating it? Because, I don't know how you can differentiate that if your point of regulation that the opt in regulation system is the person who owns the dispensing equipment. Because they don't have control…they don't have the management control. They are not making the decisions to import the LNG for their fleet operation. So that is why I see the difficulty here in differentiating natural gas, as to whether you are or not. The only way you have a regulated source is if, and I'm just going to throw this out there, Northwest Natural Gas is contracting or bringing imported LNG and NW Natural also operates a bunch of filling stations. That would be one hypothetical. Let's say they don't, because I don't believe they do. Most of them are title partnerships and the partner actually has title to the equipment. What happens with the customer who is receiving that? That is where I see that is the challenge of how you laid this out with the fuel dispensing equipment. I actually like that and I feel that is pretty close to what they will recommend on the electricity side. What is tripping me up is this differentiating between opt in and regulated.
- I can see our fuel dispenser guy could call up his fuel provider and say "What is your mix with North American and what is your mix with LNG?", and then maybe there is a different CI. Then that assumes a mix of those two. And so he is not given as much credit, because there is a greater percentage of imported LNG as part of that. It is almost an analogy of how electricity might work, at that point. What if there is a really lousy hydro year and higher carbon one year, and then the underlying mix is not as low carbon as it has been in the past.

- I just want to join the discussion here. So would CNG that was made 100% from imported LNG would it be over the carbon intensity value? *Response (CARB): It is possible that it would be very close.*
- So you might want to say that CNG that was not from North American sources that was not blended in with the pipeline, but that was sold directly as transportation fuel. That is unlikely a very small market, but that particular case would be regulated if it sold as transportation fuel. And then otherwise, if it is blended in the pipeline then I think Kyle is going down the right path. That when the person who owns the fuel dispensing equipment chooses to opt in they are going to get a carbon intensity value that represents the blend."
- Did we want to follow up with the point about if the percentages of imported LNG and the mix goes above some point would that automatically make pipeline fuel regulated as opposed to opt in to the extent that someone is selling it as transportation fuel. I guess there is some point you would have to wonder if it was going to be high enough to be worried about. Or whether the blend always going to be lower than the standard for gasoline or diesel and you just field differently with opt in?
- Practically speaking, if an LNG terminal is built and operated at the utilization factors that we are talking about, we will never breach that low carbon fuel standard.
- So we agree that there are no objections to this? Then I just want to reiterate Andy's proposal to make sure there is no objections to that. All CNG that comes out of a pipeline can opt it, any CNG that comes from LNG is not blender into the pipeline is regulated.
- So what you are saying is that they are all regulated by low carbon fuel standards because CARB has determined that the LNG uses of carbon are of higher intensity than diesel? How is it that they are regulated from the beginning?
- I think there is a fundamental policy question here and that is, do you want to introduce a barrier to the adoption of LNG transit vehicles, for instance. If you want to introduce a barrier to that you will make them regulate it. That is a barrier. It is a hurdle that must be overcome to, and maybe it's easy and maybe it's not, but it is a hurdle. So that is the question that you have to ask yourself whether it is regulated or whether it is opt in. Opt in and maybe they get to come in anyway, but regulated you are creating one more layer of difficulty for them in this process, which could be beneficial.
- There are 155 gasoline licensed dealers. So you have 155 entities in there and I would guess that most of them, maybe all, sell diesel also. They are different entities than the diesel licenced use fuel sellers.
- So what we are saying it those entities would be the regulated entities. That's what we are saying, for both the gasoline and the diesel.
- You would want to reword the regulation to say they are licensed and they are also distributing diesel then they would be regulated.
- How would one of these fuel dealers track where the fuel came from and what carbon intensity is? Generally, the fuel is coming from the terminal, and the operators of the terminal get their fuel from import.
- Can you can determine the difference between fuel that came from a terminal from Saudi Arabia or from fuel that came from California?
- It is not that much an issue for the gasoline itself, because all gasoline will have the same carbon intensity. The issue is of the blend stock, which is going to be the quantity and the type of ethanol.
- So they will have that information and you are going to be asking if they know the carbon intensity of the ethanol because of how the ethanol is made. So from California it would be the first producer of the ethanol that would be the regulated entity or importer but not necessarily the dealer who is distributing it.

So that might be a question to think about. Maybe the scheme works for the gasoline and diesel, but not necessarily for the ethanol.

- If you had a high super diesel blend stock, it has to come in and get mixed somewhere and somebody has to have a record of those two parts coming in and giving blend to get carbon intensity numbers of the terminal. So that is really the piece of the import or in production. So it needs to be regulated there before the terminal. Because the terminal is the blending area, right. So you are going to have that large scale then it's got to be up streamed at the terminal.
- I am sure that none of the fuel distributors know whether or not the ethanol they are selling came from Brazil or Idaho. Very few."
- Some will know, because because of the value.
- The terminal will know what it bought.

Options presented for biofuels/gasoline/diesel regulated party:

Option A: the regulated party for biofuel or petroleum is the producer or importer

Option B: the regulated party for biofuel or petroleum is the ODOT fuel tax payer

- From our point of view we like Option A. I think you are dealing with fewer parties there. It is where the action is happening.
- Option A versus Option B. Option A digs further upstream. Your original proposal doesn't necessarily track the taxing and ODOE information and may require the regulator to do something additional that they are not doing right now. Option B, which would have looked more to the 155, are more in line with ODOT taxing and has an ease of use and ease of implementation going for it, but it sounds like it has some difficulties in terms of the bio fuels, or at least a piece of it. How that information be pulled together and recorded.
- Option B is less flexible than A.
- One other consideration is that on Option A level they don't necessarily know if that fuel is being sold into Oregon or into Washington or somewhere else. Versus on Option B, I think they do know exactly that is sold in Oregon.
- This is difficult. In Option B, it's based on what is sold in Oregon. And Option A is not. Because something ends up in an Oregon bulk plant or is taken by an Oregon truck doesn't necessarily mean that it is going to be sold in Oregon. That person could be making a route through the stations in Oregon and in Washington and be all over the place. It is a much greater burden to do the record keeping on that. The reason why Option B for reporting purposes is much nicer is it is easy. If there is any way that we can get whatever numbers that are available on feed blend stock then that is probably the better way to go, with less burden to industry.
- There are two options to explore. One would be to use Option B for gasoline and diesel but not for the bio fuels. I don't know if that is easy to separate out. But they could go through an Option A approach and the other option would be what Paul said. Whether or not you could go with Option B for everything, but that the terminals would have to get the information on the carbon intensity somehow."
- The terminals would have to report the carbon intensity content into the dispensed blended fuels.
- They don't put it in their tanks if they don't know what it is.

- One of the points I wanted to raise is one of the reason we wanted flexibility in the system is you have to keep in mind that this has to be done in cooperation. These should marry to each other in my opinion. Secondly, we want flexibility, because one of the advantages that flexibility gives us is that an Oregon producers can create a relationship with a user allowing an increase in the level of the bio fuel use. And you want those two parties to be able to trade directly through each other, so there is a potential financial exchange relationship there, an economic relationship there that incentivizes that. So you want that flexibility.

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- Under the example of a gas station that hires a truck to pick up fuel from out-of-state and deliver it to the gas station, that truck owner has the compliance obligation and cannot transfer the compliance obligation, correct? ***Response:*** *That is correct, under that option.* And in that case the producer out-of-state of that fuel may or may not have transferred the compliance obligation. That's a private transaction. ***Response:*** *Yes, that's right.* In this example, the truck owner is not just a commercial trucker, but is a distributer or jobber, and that is the concern. Truckers don't own the cargo they haul. ***Response:*** *Correct, so it would be another distributor.* The taxes paid on that product is whoever imported the fuel, and in this case it would be the owner of the gas station. They can't refuse the tax obligation. ***Response:*** *If the gas station owner owns the fuel as it crosses the border into Oregon, they would have to take the compliance obligation under this option.* So are you saying that whoever has the tax obligation is the one that is required to report? ***Response:*** *There is a little more nuance than that.*
- Under the new ODOT rules, if a trucking company takes delivery of the fuel they can then submit the tax to ODOT. ***Response:*** *Do they own the fuel?* Yes, it's their fuel. This is not a for-hire trucker trucking fuel, this is a trucker that is receiving fuel that is used in their own trucks for fleet use. They shouldn't be a regulated party. ***Response:*** *But under this option, they would be.* The purchaser can refuse the compliance obligation if they're not the importer. But who's the importer? The importer is the petroleum company with respect to the fuels tax, not the entity receiving the fuel. They don't usually give up ownership of the fuel until delivery. It was never the intention to regulate trucking companies under the LCFS, so I want to make sure that you aren't. ***Response:*** *No, right.*
- Where you would not have a fuel tax obligation and still be the regulated party? ***Response:*** *Going back to the nuance, once an entity is defined as an importer, if they own the fuel as it crosses the border into Oregon, they become an importer. This means that they cannot refuse the compliance obligation for any fuel they purchase in-state. So it's really important how you define the importer.* So basically what you're saying is that you're trying to discourage rogue importers. ***Response:*** *In the June committee meeting we discussed exempting small importers but most of the distributors felt that would be unfair, so we are not proposing that. But we are concerned that someone who gets a truckload of fuel would be an importer, so we came up with an option where we created the definition of the small importer who could refuse the compliance obligation for fuel delivered and purchased in state.* ***Response:*** *(Paul Romain)* Frank, realistically, how many small gas stations along our border are arranging for their own fuel imports from across the border? ***Response:*** *(Frank Holmes)* I don't think very many. ***Response:*** *(Paul Romain)* They're small, which means they don't make money and they don't have the infrastructure to do this. So you have a solution in search of a problem. ***Response:*** *So you see option two as unnecessary.* I think you basically say that when you're bringing the stuff in you're the regulated party, and basically mirror the ODOT approach.
- There is an option in ODOT's administrative rules where the importer can pay the tax and the recipient can also pay the tax if they choose to do so, but the importer has to report the import. So as long as the importer is required to report the import, then I'm okay with that option.

- Do most of the perimeter stations acquire out-of-state petroleum products through WSPA members? ***Response:*** *(Paul Romain) This isn't like beer distribution where you can only have Oregon distributors distribute in Oregon. This is petroleum, so you could have a Washington distributor distributing in Oregon, or an Oregon distributor distributing in Washington. If they are distributing fuel in this state they are going to be paying tax in this state, regardless of where they are located.*
- If a gas station is importing and has a compliance obligation, would we need to have a mirror report from the out-of-state distributor? ***Response:*** *(Bob Russell) They are currently required to report to ODOT as an importer of fuel. You have imports and exports, and the net is basically what gets taxed. So there is a system that is more defined with gas than for diesel because the point of taxation for gas is the rack, and the point of taxation for diesel is the point at which it is put into the vehicle. What prompted the change in ODOT rules was to address situations where fuel is delivered to a farm and the farmer has a choice to either have the tax paid by the outfit that delivered the fuel, or pay the tax themselves. There is then an assurance on the part of the farmer that ODOT is going to treat that diesel fuel as tax exempt on the invoices they send to ODOT. In the past the farmer didn't have the option of paying the tax, that had to be paid by the importer and if the importer didn't pay the tax, because the incidence of taxation is when the diesel goes into the truck, then the farmer was on the hook for those taxes. So in order to let the farmer off the hook, they were allowed to pay the tax themselves so that the farmer could provide proof that the tax was paid.*
- Let's finish talking about gas before moving onto diesel, because we are confusing the two. ***Response:*** *Actually, we are proposing the same thing for diesel.*
- So is the farmer an importer under the LCFS program? ***Response:*** *(Bob Russell) You could look at it two different ways, and I need to be sure that we are looking at it one way and not the other. That it's the person that has the obligation of reporting the import to ODOT, that's the person who would be the regulated party.* ***Response:*** *It would be whoever owns the fuel, so is that the same person?* ***Response:*** *(Bob Russell) Usually it is, that's a contractual thing.*
- Regardless of whether a truck importing fuel is owned by the purchaser of that fuel, is there a way to tell how many small gas stations on the outlying edges of our state would take possession of the fuel before it was transported into the state? Because that's what gets at the definition of importer and how many small gas stations would be affected by the definition. ***Response:*** *(Bob Russell) ODOT's definition is slightly different than what you're proposing. They are more strict on the definition, because it's the person that brings the fuel across the border that is the importer.* No matter who owns it at that time? ***Response:*** *(Bob Russell) Yes. Ownership is almost always at the FOB destination.* ***Response:*** *So then would the definition we're proposing be workable?* ***Response:*** *(Bob Russell) I think so. I just want to make sure that what we're saying is that anyone that takes bulk delivery of fuel does not become a regulated party under the definition.* So as long as it's FOB, they don't, but if they actually take ownership out-of-state, then that farmer might be an importer. ***Response:*** *(Bob Russell) Which is why the definition of an importer being proposed for the LCFS is different from ODOT's definition. I've said from the beginning that the ODOT system should be used because that gives you the ability to do your compliance piece in the easiest possible way because ODOT already has all the reports.*
- It sounds like we don't need the distinction between small and large importers because the fact that you might become an importer, if you're a small gas station, you might make the decision to make the transaction in a certain way so as not be considered an importer.
- It sounds like most of the smaller gas stations are already receiving fuels in a manner that allows them to not be considered an importer. The gas stations aren't the problem, it's the farmers. ***Response:*** *Farmers are exempt.*

- Once the incidence of taxation occurs, then it adds another level of complexity that can affect the trucking industry. If we're using the ODOT definition of importer, then I'm fine. You need to use the ODOT definition of importer. ***Response:*** *Okay.* As long as you're consistent with the ODOT definition, then I'm good with proposed definition of regulated party. ***Response:*** *The ODOT definition is different than whoever owns the fuel when they bring it in.* They aren't doing it by ownership, they're doing it by who causes the import or export activity. They recognize that the contractual nature of ownership can be different under different circumstances.
- I'm still fuzzy on who causes the economic activity; because the gas station will be ordering fuel, they're causing the economic activity because otherwise there would be no delivery? ***Response:*** *(Bob Russell) If there's no customer, then there's no delivery of fuel, agreed. But the ODOT system doesn't follow the way you've described. They don't want to get involved in the contractual relationship between buyer and seller. The guy that owns fuel outside of Oregon and is going to sell it in Oregon is the guy that is considered the importer, under the ODOT system. In most circumstances it's FOB destination so the seller truly does own the fuel, but I could envision a situation where that may not be the case, but in ODOT's system they ignore that.* ***Response:*** *(Paul Romain) The importer is whoever owns the fuel and then causes it to be shipped into Oregon, and that person is responsible for reporting to ODOT for tax purposes in most instances, but there is an option with diesel.* So would the gas station who ordered the fuel be the entity that caused the fuel to come to Oregon, or would it be the distributor who supplied the fuel? ***Response:*** *(Paul Romain) Technically, both of them caused the import, so forget the word 'caused'; the bottom line is if you're bringing fuel in from out of state, you're the one who has the obligation regardless of whether you use your own trucks or hire a trucking company to transport that fuel into the state.* ***Response:*** *(Bob Russell) ODOT issues licenses and stickers that are different. In the example of a farmer, they would get a users license and sticker which gives the farmer the option to pay the fuels tax themselves. The petroleum provider has a seller's license and sticker, so it attaches to the certificate.* So that's the answer: It's the petroleum user or petroleum seller that has the obligation of tax and/or report to ODOT, period. ***Response:*** *So if a gas station received a shipment of fuel delivered FOB, who would be the importer?* ***Response:*** *(Bob Russell) The seller, always.*
- Is that going to cause some enforcement problems if the regulated party is located out-of-state? ***Response:*** *(Paul Romain) For tax purposes it doesn't, and it shouldn't for anything else.* ***Response:*** *(Bob Russell) This follows the existing reporting systems.* This creates a new compliance obligation for a lot of parties, so that might discourage marketing in Oregon. ***Response:*** *It won't necessarily be the person that pays the ODOT tax that has the compliance obligation.* ***Response:*** *(Bob Russell) Correct, but in most cases it will be.* ***Response:*** *Okay.*
- Request for committee input on draft economic analysis by Thursday, October 21, 2010.
- Will we see the draft rules in November, or just the final DEQ LCFS report? ***Response:*** *Just the final report with the proposed program structure. At the next meeting we would like to spend some time talking about the last committee meeting and what comes after that in terms of our post-committee vetting process and how you will be given the opportunity to see the rules, among other topics. November's meeting is when we will address the committee's request to review the whole program structure. At that meeting we will look at all of the proposed elements together. And December's meeting will cover anything we haven't wrapped up in our November meeting.*
- In terms of rule timing, will the report be done before the Legislative check-in in February? ***Response:*** *The rules are complicated, and we need to have the benefit of these last few discussions to finalize that, so I think it's best at this point to focus our energy on the final report and the economic analysis which means the draft rules might lag by a month and that would be part of the post-committee process we will discuss with regard to how we will receive your input.* ***Response:*** *(Bob Russell) My understanding from*

previous discussion is that the committee wouldn't see draft rules until sometime next year, and probably not in the first six months. ***Response:*** *Right, not proposed rules, but a model rule that people could see the rule language in addition to the overall structure of the program.* Will there be a fiscal impact along with those rules? ***Response:*** *Not in that step. If or when we get to the point of actually proposing rules for adoption, that would include the fiscal impact analysis in our usual rulemaking process. We won't be able to get all of that done by December, so we want to concentrate on the report and have the model rules probably a month later.* If we give the legislature a model rule with no fiscal impact because we're going to do proposed rules down the road, it seems like they'd be getting half a loaf. ***Response:*** *The economic analysis is part of that package that they will review.* ***Response:*** *(Mark Reeve, Chair) The fiscal impact shouldn't differ from our economic analysis unless the rules are different than what we've discussed.* ***Response:*** *In our report to the legislature, we'll have things to discuss that go beyond the economic analysis, such as implementation questions, resource questions, etc. So I imagine our report would be more comprehensive, but would have to include this committee's report, the economic analysis and other aspects of the fiscal impact of the rule and then we'll have a fiscal impact statement, but we wouldn't be proposing adoption at that point. We've heard from many people that they would like to see in detail what our draft rule would look like.*

- My understanding of this process is that in November we will have the economic analysis report, we'll get a better view of what the program will look like in December, we'll have a more complete report to the legislature to show that we're making progress and what the economic impact of the program is expected to be as it's being proposed and this update isn't supposed to be looking for legislative approval but is intended to show the progress being made. And then we will begin the process of EQC rulemaking next summer. What is the target date for that – are we coming up with a proposed rule throughout the Spring and then looking for the EQC to begin the rulemaking process? ***Response:*** *The rulemaking process typically takes six to nine months. So we hope to start the rulemaking towards the end of the legislative session and have something adopted by the end of the year, but we don't have a rulemaking schedule established yet.*

- If we go with what we're proposing in terms of the compliance schedule, wouldn't we need to make regulated parties aware of what the rule is by the end of 2011? ***Response:*** *Hopefully the model rule will be what we propose.* ***Response:*** *(Bob Russell) The first year would be reporting only, which is 2012, so 2013 would be the first year of compliance?* ***Response:*** *That would be roughly the schedule.*
- There is some balancing to do in terms of the timing of the fiscal impact analysis because if you do it too early and the rule is modified it can be out of date. ***Response:*** *(Bob Russell) And that's a very important piece and it almost seems like we are going to be out of step because I agree that until we have a final rule or close to it, it's hard to calculate those impacts. I think the legislature is going to want some oversight in terms of cost to the agency and budget limitations at some point – when is that point?* ***Response:*** *As part of our reporting back to the Legislature in this next session, we'll talk about implementation of the program, the resources we would need to implement the program, and I think the budget would come from there. I don't know if it would be in that session or in a following session.*
- Will DEQ be asking for legislative approval this session for all the funding needed for the whole program? ***Response:*** *I don't think so.* ***Response:*** *(Mark Kendall) There was a fiscal and a revenue pack submitted with the legislation when it passed and the final report would indicate if there was a wide separation from the fiscal and revenue impact that the legislature approved.*
- Is part of the administrative process a requirement that a new fiscal be done? ***Response: Every*** *rulemaking will have a fiscal.* ***Response:*** *(Mark Kendall) But that's a rulemaking, not a statute.* ***Response:*** *The rule is not proposed at this point. Mark is right because the EQC could change what is proposed.*

- Correct me if I'm mistaken, but my understanding is that the budget provided staffing to conduct the rulemaking, it didn't provide any staffing to implement a rule. You're going to need a budget to issue whatever is necessary to impellent the rule. Funds are going to have to come from somewhere, so there is going to need to be some kind of legislative action prior to the time that DEQ implements the rule. The questions is, is that something that you are going to go into the 2011 session with, or are you waiting to 2012 assuming we'd have a special or annual legislative sessions? ***Response:*** *(Brock Howell) I think this is a question for Andy, so maybe we can get a quick response from him to that question to the committee members.* ***Response:*** *Sure. We will talk about to the legislature about the resource needs to take the program forward. When and how much and if we ask for it, I don't know.*

Summary of written comments from advisory committee member or alternate November 5, 2010 regarding regulated parties.

- If we're looking at Oregon in isolation, have we calculated in an avoidance factor? Given our aversion to biodiesel at the moment, and if there is a price differential, then there should be an avoidance factor for both rail and trucking, because we are capable of buying fuel elsewhere. ***Response:*** *(Michael Lawrence, JFA) We can think about that in the change – remember what we provide to the model is dollar expenditures for fuel and if we were to reduce that by some portion we'd have less impact. That could be done but the fuel taxes would still have to be paid to Oregon since you pay taxes on where you drive.* Oregon doesn't have a fuel tax. ***Response:*** *(Michael Lawrence, JFA) The weight-mile tax applies.* ***Response (ODOT):*** Oregon does have a fuels tax, however, if the vehicle is over 26,000 pounds then the weight/miles tax is paid. In Oregon you either pay the fuels tax or the weight/mile tax but not both. There are exceptions, like with farmers or split weight vehicles.
- Michael mentioned the only benefits in this analysis are due to the plant construction in-state. With the scenarios being discussed, would this avoidance factor then eliminate that positive impact and add a negative to it? ***Response:*** *(Mark Reeve, Chair) I thought I heard Michael say that it would be an overall reduction of fuel use potentially, and if truckers that fuel their trucks in Washington drive through Oregon and re-fuel in California, what percentage of fuel use in Oregon it could represent. And that percentage reduction of fuel use would come off the overall gains and losses running through the model, so unless you have a huge plant that is anticipated to be built doesn't get built, I'd think you would bring down those benefits proportionately.* ***Response:*** *(Michael Lawrence, JFA) I'd have to think about it a little more, but I can't think of any other. You have to pay fuel taxes in Washington and weight mile tax in Oregon, so that would make it less desirable to try to avoid re-fueling in Oregon.* That's not correct, the tax system is based on where the fuel is burned, not where it's purchased, so you're going to pay the same amount of tax no matter what state you're in. So tax is not a motivator. ***Response:*** *(Michael Lawrence, JFA) In terms of location of fuel purchase.* Correct. While I agree with you that the total amount of fuel we're talking about is small because gasoline is consumed in much larger quantities than is diesel in Oregon, but it is a significant portion of the diesel consumed. ***Response:*** *I think it's an effect they could explore, maybe as a sensitivity analysis of "x" amount of fuel is able to be purchased out of state.* You're missing the point, because at one point we said we're looking only at Oregon, and now we're looking at effects of a LCFS regionally. ***Response:*** *No, I'm not looking at it regionally, I'm questioning whether your scenario of avoidance is realistic when you consider that California already has a standard, Washington is considering a standard, and our indication is that the price isn't going to be different and so you have a scenario that we could look at sensitivity on to see if it makes a difference.* Based on what you're saying the investment scenario needs to reflect that there is going to be demand for low carbon fuels in Washington and California too because of their standards, which would impact the location of plants. ***Response (ODOT):*** *This would not be the case as the fuel taxes are considerably*

higher in both Washington and California. Fueling in Oregon would actually be a savings. You only pay weight/mile tax on vehicles over 26,000 pounds. Vehicles under that weight are subject to the fuels tax.

- This raises the question of how we're accounting for compliance. We discussed using the weight-mile tax as the numbers we'd use for the net amount of fuel used in the state, and if we're using that number to hold accountable the system, then we would have to figure out how that would work. ***Response (ODOT):*** *This is incorrect. As the point of taxation for diesel (use fuel) is at the user level and in Oregon you either pay the weight/mile tax or the fuels tax, this method would only capture the gallons "reported" to MCTD, none of the gallons "reported" to FTG and none of the gallons sold in bulk and never reported.*
- If a gas station is importing and has a compliance obligation, would we need to have a mirror report from the out-of-state distributor? ***Response:*** *(Bob Russell) They are currently required to report to ODOT as an importer of fuel. You have imports and exports, and the net is basically what gets taxed. So there is a system that is more defined with gas than for diesel because the point of taxation for gas is the rack, and the point of taxation for diesel is the point at which it is put into the vehicle. What prompted the change in ODOT rules was to address situations where fuel is delivered to a farm and the farmer has a choice to either have the tax paid by the outfit that delivered the fuel, or pay the tax themselves. There is then an assurance on the part of the farmer that ODOT is going to treat that diesel fuel as tax exempt on the invoices they send to ODOT. In the past the farmer didn't have the option of paying the tax, that had to be paid by the importer and if the importer didn't pay the tax, because the incidence of taxation is when the diesel goes into the truck, then the farmer was on the hook for those taxes. So in order to let the farmer off the hook, they were allowed to pay the tax themselves so that the farmer could provide proof that the tax was paid.* ***Response (ODOT):*** *Not even close for diesel. Diesel (use fuel) is not taxable until it is used upon the roads and highways of the state, therefore, there is no restriction to "importing" diesel in any amount for any reason. Use Fuel "importers" are not required to be licensed under the current statutes.*
- Let's finish talking about gas before moving onto diesel, because we are confusing the two. ***Response:*** *Actually, we are proposing the same thing for diesel.* ***Response (ODOT):*** *This is problematic because they are treated differently in ODOT statutes.*

Summary of written comments from advisory committee member or alternate December 1, 2010

- Long-term, plug-in cars powered by renewable energy are likely to be the best technology to reduce global warming pollution from the transportation sector. To make sure that plug-in cars and plug-in infrastructure can take advantage of the LCFS as a market driver, the electricity optin period should extend beyond one-year. In addition, because plug-in cars are likely to improve in efficiency, the EERs for all vehicle types should be periodically reassessed.
- Utility companies should not be eligible for credit generation under OR LCFS. As we noted during the November 16th Advisory Committee meeting, Clean Energy does not believe any "utility company" should be eligible to generate LCFS credits unless it generates such credits through an investor-owned subsidiary that cannot "rate-base" or "cross subsidize" the cost of infrastructure (i.e., a home refueler or charger, public or private CNG/LNG fueling station, public or private electrical vehicle charging station) or the price of fuel (i.e., electricity or natural gas). The Draft Final Report mentions "utility company" for CNG under Section 2b), for LNG under 2c), for biogas under 2d) and may be inferring a "utility company" for electricity providers under 2f) with the use of "electricity provider". Incentivizing utilities to enter the market for alternative fuel infrastructure through the use of ratepayer funds will create an anti-competitive environment. Private enterprise (i.e., Clean Energy, Trillium, ALT, Prometheus, etc.)

would struggle to compete as such entities do not have the ability to crosssubsidize with profits from a regulated monopoly. Incenting utilities by allowing them to generate credits is likely to limit market development and thus limit the state's ability to achieve its LCFS goals.

- In other words, utilities should not be permitted to participate directly in the natural gas vehicle fuel business, such as NGV refueling, that compete with non-utility enterprises because ofthe risk that they will engage in anti-competitive conduct (e.g., below cost and cross-subsidized pricing of the refueling services provided to the retail customer). If the holding companies of the utilities want to participate in market activities which result in the generation of credits, they should do so on an unregulated basis with the same terms, conditions and risks facing any non-utility enterprise and without any benefit from inappropriate affiliate transactions with the utility. In this situation, and only in this situation, the non-regulated affiliate of the utility would be the "fuel provider" that would be entitled to receive the benefit of any LCFS credits that are generated as a result ofthe affiliate's activities which generate the credits. Furthermore, allowing utility companies to rate-base or cross subsidize their costs to provide natural gas vehicle or electric vehicle infrastructure or fuel pricing would not be fair to non-participating rate-payers who would not benefit directly from such investments. Clean Energy therefore objects to direct utility company participation in LCFS credit generation without the use ofan investor-owned unregulated subsidiary for CNG, LNG, biogas or electric fueling.

- CNG Opt-in definition of"energyserviceprovider"under2b). Under the "At a Glance" section of the document and Section 2B on page 55 itself, the "opt-in parties" for Compressed Natural Gas (CNG) are defined as "utility company, energy service provider, or any entity that owns the fuel dispensing equipment in Oregon for transportation use", Clean Energy wants to make sure that the DEQ definition of "energy service provider" means third-party fuel providers of CNG. At the November 16th Advisory Committee meeting, it appeared DEQ staff concurred with this interpretation and we wanted to raise this initial concern to you in writing so that staff may further clarify this definition in the narrative.

- LNG Opt: in definition and figures should be further clarified under 2c) to reflect DEQ intent. During the November 16th Advisory Committee, DEQ staff clarified its position on what kinds of LNG processes would be subject to regulation or would qualify for opt-in status. Specifically, DEQ made it very clear during the meeting that LNG subject to regulation would be imported LNG that never enters the pipeline system and is directly trucked to a fueling station versus opt in LNG that is either imported and blended in the pipeline system or LNG that is produced from North American natural gas from the pipeline system and then trucked to a fueling station. Unfortunately, the current definitions under Section 2c) and figures 3 (page 56) and 15 (page 116) fail to clearly make this distinction. Clean Energy therefore recommends making the following changes:

- LNG from fossil sources -"Opt-in: Any LNG produced from natural gas supplied through a pipeline" Clean Energy supports DEQ's use of the phrase "natural gas supplied through a pipeline" as we believe LNG produced by natural gas from a pipeline anywhere in North America should qualify for "opt-in" status. That said, Figure 3 and Figure 15 could be interpreted to read that such fuel would not qualify for "opt-in" status and would be regulated if fossil-based LNG is produced from the pipeline system outside of the state and trucked into the state to a fueling station. Note that the language used to describe the first phase of four phases for both figures under the regulated pathway reads, "LNG barged or trucked into Oregon". Clean Energy therefore recommends that the first phase of the "regulated fuel" pathway read, "Overseas LNG barged to the US". This modification of the pathway would clearly show the intent of DEQ: to regulate fossil-based LNG that fails to blend with North American natural gas within the pipeline system.

- Clean Energy supports DEQ 's decision not to regulate overseas fossil-based LNG if it is blended with North American fossil-based natural gas in the pipeline system. Clean Energy would like to express its support of DEQ's decision not to regulate imported fossil-based LNG from overseas if it is blended in the pipeline system with North American fossil-based natural gas. Clean Energy believes that the amount of imported natural gas from overseas will be small if imported at all given the significant resources of natural gas available in North America. Estimates to date are over 200 years of proved reserves of fossil natural gas based on 2008 consumption levels in the U.S. and this leads Clean Energy to believe that there will be an insignificant percentage, if any, of the natural gas made available to the state of Oregon and the United States from overseas. In fact, since natural gas as a commodity in the U.S. is at $3 to $4 per mmbtu at current market prices and international prices are around $7 per mmbtu, it's hard to understand why imported natural gas would be shipped to US markets under current market conditions.
- Clean Energy urges DEQ to change how it attributes credit generation to "Biogas (CNG and LNG) ". Clean Energy is very concerned as to how DEQ defines what constitutes an "opt-in" party for biogas if the biogas enters the pipeline system. Clean Energy believes that the definition will: (a) slow or kill any viable projects within the state; (b) prevent any potential biogas shipments into the state from out-of-state to help support the state's LCFS; and (c) again float the possibility that a "utility company" can participate in the marketplace, creating an anticompetitive environment with its ability to rate-base and cross-subsidize projects. Specifically, Clean Energy strongly objects to the language found on page 57 of the Draft Final Report on that states: "If the biogas is injected into the natural gas pipeline (this does not occur in Oregon, but it could), the producer would earn and sell the natural gas to a natural gas company. If the natural gas company dispensed a volume of natural gas equal to the biogas they had bought for transportation, they could earn and sell credits for that volume of biogas bought." Clean Energy believes there are several options that the DEQ should consider to ensure that the "chain-of-custody" of biogas would be retained by the biogas producer once the biogas product enters the pipeline.
    - Pipeline Transfer Fees to Retain Chain-of-Custody of Biogas. Biogas fuel producers should have the ability to retain the rights to their product and market and sell that product to the end-user, even when the biogas is injected into the pipeline system by paying pipeline transfer fees. Specifically, if the biogas fuel producer pays the pipeline operator for the transfer of biogas through the pipeline system, this can serve as the "chain of custody" required by DEQ to demonstrate the physical delivery of the biogas to the fueling station. Of course, this option has the downside of adding unnecessary costs to in or out-of state biogas production and that is why we would urge DEQ to strongly consider biogas swaps.
    - Biogas Swaps. A second option that Clean Energy hopes DEQ would consider over the requirement of paying pipeline transfer fees to create a "chain of custody" would be for DEQ to allow "biogas swaps": the practice whereas a biogas producer contracts the production and sale of biogas to a specific customer without the actual physical transfer of the biogas to that customer. This is a common practice in the electricity market as the approach eliminates the expensive pipeline transfer fees associated with physically transferring the biogas from point A to point B while ensuring the continued production of biogas. The reason why biogas swaps should be accepted is obvious: greenhouse gases that cause climate change are not considered "local pollutants with localized impacts" like criteria air pollutants and the energy swap policies encourage the development of economically viable biogas projects throughout the county by providing carbon compliance to sell the biogas. This ultimately enables the largest reduction in greenhouse gas emissions. While Clean Energy sensed that DEQ would prefer to have a system that could physically demonstrate the transfer of biogas to a fueling station, DEQ should be aware that this adds a significant premium to the cost of producing perhaps the lowest carbon fuel available on the market today and could actually make

some biogas production projects economically infeasible. This is not an outcome or hurdle that Clean Energy believes DEQ would intentionally want to establish. Further, not allowing biogas swaps also creates an unfair advantage of electricity over gas. If it would be useful, Clean Energy would be more than happy to work with staff to create this option for future biogas sales that would support the Oregon LCFS's goals of a 10 percent carbon reduction by 2022.

- Clean Energy believes it would be helpful for DEQ to better define how a party would qualify as an "opt-in party" for CNG, LNG and biogas (CNG or LNG). The Draft Final Report, as it is currently written, is virtually silent on this detail and Clean Energy believes that it should be defined so that it is clear under the LCFS who is actually generating the LCFS credit for fueling a natural gas vehicle (NGV). Clean Energy, therefore, urges DEQ to consider how the California Air Resources Board defines each ofthe respective parties as each fuel (CNG, LNG and Biogas) has their own distinct process or pathway.
- Specifically, natural gas on its own is not a vehicular fuel. It either needs to be compressed or liquefied before it can be used by a natural gas vehicle (NGV). The California Air Resources
- Board (CARB), with this understanding ofthe NGV Industry, decided to define the "opt-in" party for each fuel as follows:
- CNG: The owner of the fueling infrastructure that compresses the natural gas.
- LNG: The entity that delivers the LNG to the fueling station.
- Biogas (CNG or LNG): The producer of the biogas.
- CARB defined the "opt-in party" for these various forms ofnatural gas to identify the party that actually "enabled" the fuel to be used in the vehicle. For CNG, natural gas needs to be compressed. The party that invests the monies to create the infrastructure to compress the fuel should rightfully take the LCFS credit under the LCFS program. For LNG, the physical delivery ofthe fuel to the LNG fueling station is the enabler and therefore defmes the "opt-in party". As for biogas (CNG or LNG), this should favor the biogas producer to remove any barriers that could be created by diminishing the profitability ofbiogas production. Clean Energy will provide CARB's exact language to DEQ as an appendix to these comments.

4. Exemptions

November 3, 2009 Advisory Committee Meeting

- Non-road fuel is not as available as many farmers would like. Some have to drive 30 miles to buy it.
- Most gas stations have two underground tanks, one for premium, and one for regular. Mid-grade gasoline is produced by blending the two. Some stations have a third tank for diesel.
- The approval process for new tanks is said to be longer than two years.
- Railroads are said to use the same fuel as trucks as both come from the same supply.

December 3, 2009 Advisory Committee Meeting

- If producers less than 10,000 gge equivalent are proposed to be exempted, and that is the volume of the smallest producer, then no one would be exempted. ***Response:*** *That is a suggested starting point – the* *idea is to give the smallest producers time get up to production volume before being regulated. DEQ is open to other suggestions.*

- Need to consider barge system, towboats, etc.
- With regard to intrastate locomotives, the definition of "intrastate" has to do with where the shipment is going, not where the locomotive is going. So a truck could be transporting wheat to a silo, which then gets put on a train out of state. That truck movement, although never leaving Oregon, is interstate commerce because the wheat is destined for out of the state. Some trucks are captive and will fuel in Oregon, but 90 percent of trucks registered in Oregon are engaged in interstate commerce and could probably fuel elsewhere. ***Response:*** *What DEQ is concerned about is the fuel, not the goods that are being shipped. An interstate locomotive is likely to fuel outside of Oregon, as could the oceangoing vessels. DEQ will look into the definition of intrastate railroads. Farm and log trucks are exempt, but the truck owners themselves would not be subject to the LCFS. What is important is that the fuel they use is exempted. So we're not talking about exempting the interstate locomotives, but the fuel they use. The question is about the fuel and the fueling system and can the fuel be supplied separately.*
- If you are regulating at the blender level, how will you separate that out?
- What about fishing vessels? The entire fleet is legacy. Should we consider granting them the same considerations as logging trucks?
- Commercial construction equipment, off-road equipment fuel is supplied in two ways. Some companies own their own equipment, others rent. So when you're talking about this in relation to the construction industry, it is very complex – some are small businesses. ***Response:*** *This regulation is for the fuels, not the equipment.*
- But all of the construction equipment doesn't get capitalized very often, and what kind of retrofit or new equipment would need to be purchased to use the fuel? Some portions of construction equipment fleets have specialized uses. Even though it doesn't use different fuel, it needs to operate well. ***Response:*** *The statute requires that any biomass-based diesel or ethanol meets fuel specifications enforced by the Oregon Department of Agriculture. On-spec biodiesel should be able to function in any engine.*
- Part of the statute says the rule has to be feasible. Truck manufacturers will only honor warranties with five percent biodiesel or less.
- Of the fuels for which exemptions are proposed, some are outside DEQ's jurisdiction and some are specialized fuels that have their own specifications.
- Currently, we have an Oregon Renewable Fuel Standard requiring B2 (diesel blended with two percent biodiesel) is being distributed. We have an avenue for off-road fuel to be clear, and we have clear aircraft fuel already. For people concerned about the effect of a LCFS, what are you doing now? You're either using a clear off-road product, or you're using B2. Hence, potentially low carbon fuels are already on the market and people are using them.
- Why didn't DEQ propose to exempt all off-road? Airport and ground support or port equipment is not exempted. All of those fuels will need to use fuels that meet a LCFS spec. If that is the case, then those technologies become candidates for electrification or natural gas. In California, there are existing regulations that address this equipment, and they are working on sorting out the relation to the LCFS. In Oregon, we do not have regulations that address this type of equipment.
- Recreational boats are exempt from the Oregon Renewable Fuel Standard for a good reason. It's not a large amount in terms of quantity, but you might want to be consistent with the Oregon Renewable Fuel Standard.

- The regulated entity is the fuel provider, and not the fuel consumer, so these fuels should still be provided. It's the provider's obligation to balance the fuel mix, so there is a potential to provide for some of these consumers while making reductions in other areas. So the LCFS is not a wholesale change in the fuel mix.
- Right now farm operations use the same fuel as truckers and the construction industry. This exemption was given to the farm industry, and it seems not to mean anything because fuel providers might not maintain a separate fuel supply for the agricultural community. Maybe in some areas it might be available because out-of-state suppliers will still be bringing in fuel.
- Exempting all non-road fuel would be appropriate to ensure that fuel distributed to farm vehicles is functionally exempted from a LCFS. It is widely held that fuel distributors minimize the number of fuels they provide to reduce cost and simplify operations. Therefore, relatively small volume uses (such as farm vehicles) may get low carbon fuels regardless of exemptions. Furthermore, a LCFS has the potential to increase use of biodiesel making fuel more expensive or causing performance problems. ***Response:*** *Because exemptions dilute the overall effectiveness of a LCFS program, they should be used only as actually needed. LCFS fuels still need to comply with established fuel standards.*
- Throughout the passage of this bill (House Bill 2186) and in hearings the agricultural community heard that this would have no impact because of the exemptions. It's frustrating that this does not appear to be the case because the fuel suppliers will not be supplying clear fuel.
- Are agricultural users today getting clear, off-road diesel fuel? Yes, either dyed or clear, depending on the amount of fuel they buy. To buy clear fuel, they have to purchase a whole truckload, and there is only a small segment that can do that. The concern is the cost and availability and what the LCFS means to their business.
- If the agricultural community is getting clear fuel now, the LCFS should not affect that.
- Is it the price or perceived performance issue? During the session, the concerns were raised because of the price.
- When ULSD first became available, the Port of Portland wanted to require ULSD as a pilot project for one construction project, and there were major concerns that it would cost more, etc. It turns out that it did not cost more, because of the large supply. The more these low carbon fuels have to become a specialty fuel due to more and more exemptions, the more they will cost. There might be economies of scale if there are fewer exemptions.
- What is the nature of the burden to agriculture? If agriculture is already using fuel that is highway grade, that means they have made the fuel filter switches and the commenter doesn't understand what the cost risk would be given that the fuel would be available ubiquitously, and the cost would not be more.
- The concern is what happened with the move to 10 percent ethanol – there were significant impacts to not just the agricultural sector. We need to look at the exemptions from the Oregon Renewable Fuel Standard, because there were significant costs, not just to agriculture. Costs of engine failures, new carburetors and retrofitting because engines can't run with ethanol. The agricultural industry runs on older equipment and vehicles. B2 (diesel blended with two percent biodiesel) is a low percentage blend, but as we move to a higher percentage – current warranties allow for five percent biodiesel, but older vehicles do not have that consideration.
- But haven't they already borne that cost in the switch to ULSD? ULSD, with its higher solvency, has already cleaned out all of the tubes, so what is the additional cost?
- I think the ULSD is only on clear and not red at this time. Is there going to be with LCFS, a new change, such as a higher blend or something else that would have an impact on older engines.

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- So that is question for DEQ – is the fuel more problematic as it gets purer? This is a discussion not just for the agricultural community, but for all users.
- So far, there has been nothing but anecdotal evidence presented on the cost of increased biofuels use. Do any advisory committee members have any actual evidence or studies of greater cost or problems due to increased biofuels use?
- One member stated that federal rules require locomotives to be retrofitted in future years to reduce emissions of Volatile Organic Compounds, Nitrogen Oxides and Particulate Matter. He indicated the use of biodiesel in upgraded locomotives would nullify the equipment warranty. ***Response:*** *DEQ will investigate this issue.*
- One potential solution regarding agricultural fuel use (it wouldn't solve the whole issue with the exemptions) is that the farm coops are a large fuel buyer and they they already keep track of agricultural use of fuel for tax purposes. Some also have fuel sales to cars, but can separate out that documentation. Although, off-road fuel is not tracked for tax purposes. Could the rule be written around this existing documentation? ***Response:*** *Yes, the criteria are that the exemptions would need to be verifiable and traceable. DEQ suggested one way to achieve that end would be for final users of exempt fuels to provide simple statements of exempt use. Such statements would be aggregated by regulated parties and their total volume would be subtracted from compliance calculations.*
- For bridge construction projects that required fuel tracking, it was easy to get fuel information from a fuel supplier. It's just an accounting protocol for the fuel supplier, and is easily traceable.
- Other members also expressed concern that a LCFS would cause problems with legacy vehicles or niche uses such as sailboats (in which fuel for auxiliary engines can remain unused for years). On the other hand, one member pointed out it is likely such vehicles are already getting biodiesel; another thought any problems would be temporary and limited to clogged fuel filters.
- The committee also discussed whether exempt fuels should be allowed to earn low carbon fuel credits. Allowing such credits could provide an incentive for low carbon fuels when they are not mandated and provide flexibility in meeting a LCFS standard. Not allowing such credits could discourage the use of biofuels beyond what is already required by renewable fuel standards (in response to concerns that greater use of biofuels in exempt categories would cause problems).
- What percentage of biofuels is likely to be required? The advisory committee would like DEQ to provide information.
- Some agricultural users have been using higher blends of biodiesel, and love it.
- LCFS does not require biofuels to be blended.

Summary of written comments from advisory committee member or alternate January 15, 2010 regarding exemptions

- There is an exemption for interstate rail but not interstate barge. There are several operators including Tidewater on the Columbia and Snake river system that operate interstate as well as our harbor boats that are strictly intrastate. My question is was there any thought given to the possible perception of a competitive advantage afforded the interstate rail companies which just happen to be our biggest competitor?

Summary of written comments from advisory committee member or alternate June 17, 2010

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- On revisiting exemptions, I see the exempt parties and/or fuels of low market volume pretty well addressed in earlier discussion and decision. Given the magnitude of the influence of any exempted fuel or opt-out of provider on either the near term fuel carbon content or overall accomplishment of the LCFS, I see that as an edge discussion. We simply want any rule adopted not to provide permanent exemption for any fuel or provider or regulated entity, but to simply provide a vehicle for it to be administered by staff. We want to reserve rights in any case to remove exemption for various and obvious reasons.

June 23, 2010 Advisory Committee Meeting

- Unless you can demand a huge amount of volume, don't expect to get non-blended stuff. And that is where the exemption thing is going to cause some political troubles down the line because the folks who are exempt thought that they were going to get non-blended stuff.
- Interstate locomotives are currently getting non-blended fuels because they represent 2 million gallons of demand where the trucks are getting the mandated 2% biodiesel. The locomotives probably won't have a problem getting non-blended in the future.
- How does this fuel exemption certificate functionally get from the user to the supplier that they can then use that to take into accounting for their credit? **Response:** *There is no certificate. Regulated parties will track how much fuel is sold to exempt parties and that volume is not used in the calculation of meeting their LCFS compliance obligation. The documentation of that sale should include a statement that it is being used for an exempt use.*
- The 360,000 gallon equivalent what is that percentage rise for the volume in Oregon. Is that like 1% or 1/10%?" ***Response*****:** *There is basically 2 billion gallons statewide, approximately.*
- The marine exemption does not apply to all other watercraft and that didn't seem to be what you said when you discussed it previously. Did that change for same reason? **Response**: the exemption is *just for ocean-going marine vessels. All other watercraft uses are not exempt.*
- Water craft are exempt from the ethanol requirement. But if they are not exempt from the LCFS, so they could get a blended fuel that they don't want. **Answer:** *The marina could still provide the appropriate fuel to that boat, but the ultimate regulated party would have to make it make it up by selling more low carbon fuel elsewhere or buying more credits so the net balance works out.*
- The problem is with the language. Saying that possession of the fuel is the key in meeting the LCFS is wrong. That has nothing to do with it. They can have whatever fuel in their boat, in their logging truck, or whatever. **Response:** *Yes, that is correct. We will work closely w/ DOJ to craft some language that would apply more broadly but still specifically refer to the exempt uses.*
- DEQ should consider that consistency with the RFS is something that regulated parties would like to see. I.e. exempting water craft. This is not a technical issue, it's a political one.
- For any type of federal reservation I assume they are exempt. **Response:** *They are not exempt except for those uses specifically called out in this section of the rules.*
- Shouldn't we exclude these exempt groups from the sectors that are included our REMI model? **Response:** *Even though the fuels are exempt, there may be other economic impacts to these sectors so they should remain in the REMI model.*
- I would strongly advise as our job as the advisory committee, knowing this process and going through it in California, making it clear up front as soon as possible about who are the regulated parties in this

program. Right up until the end I kept going into CARB and saying “You are not regulating me right? You’re not regulating me?”

- With propane, if we switch from diesel to propane, can we get credit it for that even though it’s exempt? **Response:** *Propane is exempt from this program, which means that fuel distributors can’t get any credit from selling propane. Propane did not want to be a regulated entity and they would have to become one if they wanted to sell credits. We can look into whether we could write the ability for them to opt-in and then if they opted-in they would have some reporting obligations. As long as they are okay with it I think it would be beneficial to the program.*
- Six months ago, when we first talked exemptions I was basically told to wait until later in the process. Is now the time? For the economic impact analysis, is it going to be about fuel prices only? Is it not going to be about whether a whole fleet, in my case the legacy fleet/construction industry, can make happen what is going to be essentially a mandate by the fuel producer to use more low carbon fuels? It would appear to me, that there is no place in this process that an industry like mine to know for sure what is going to happen. That is why you are doing an economic impact analysis, right? It seems that we are not going to drive down deep enough to help some industries understand or help you understand what the impacts could be on industry. Am I missing something here? A whole number of industries and a big part of this advisory committee’s job is to try to understand the implementation of this program and I’m not seeing the place where that is going to happen. **Response:** *The economic analysis is going to be looking at all sectors. It is going to provide a lot of good information for you to see what we anticipate the cost of fuel is going to be and the availability of fuels and what kind of demand there might be for, in particular, on your sector. Let’s see how it comes out and then let’s revisit it.*

Summary of written comments from advisory committee member or alternate December 1, 2010

- Small producers of low carbon fuels are exempted from regulation under the LCFS as recommended by DEQ. ZeaChem supports DEQ's recognition of both individual small producers less than 10,000 gallons gasoline equivalent (gge)) and total aggregate volumes of low carbon fuels under 360,000 gge to ease the burden of introducing new fuels into this highly competitive market. However, ZeaChem is concerned that the exemptions outlined do not adequately account for pre-commercial scale production facilities, such as research and development and demonstration scale, which are needed in order to verify a new technology prior to commercial production.
- Recommendation: The language surrounding aggregate volumes is vague as it specifically applies to ethanol. The report recognizes the important role of ethanol as a low carbon fuel including current first generation corn ethanol and advanced cellulosic ethanol production. In the proposed aggregate volume exemption, DEQ should indicate that cellulosic ethanol is a separate, distinct fuel group from com ethanol since the state already has production levels of corn ethanol well in excess of360,000 gge aggregate volume. By creating a separate fuel group for cellulosic ethanol, the DEQ will recognize the advancements being made in the industry based on different feedstocks and novel technologies and processes and ensure that small volume producers of cellulosic ethanol are exempt.
- Recommendation: In addition to the above proposed modification to the total aggregate volume language for ethanol, ZeaChem respectfully submits to DEQ an additional exemption category for research, development and demonstration facilities. This additional exemption allows novel pre-commercial technologies to be established in Oregon without additional regulatory burden, thereby promoting future commercial scale production of low carbon fuels in the state. On November 23,2010, the Oregon Depal1ment of Energy (ODOE) published the new permanent rules for the Business Energy Tax Credit (BETC) program. Included in the final rule is a definition for "Research, Development, and

Demonstration Facility (RD&D)." In order to simplify state policy and regulation impacting pre-commercial scale facilities, ZeaChem recommends that DEQ include the ODOE BETC definition of RD&D facilities as an additional exemption to the LCFS. (See: OAR 330-090-0105 62(a)(A)-(C), available at: http://oregon.gov/ENERGY/CONS/BUS/docs/BETC Rules 112310-Final.pdf.

5. Setting the Baseline

January 27, 2010 Advisory Committee Meeting

- The 2007 data is fine to start with and for DEQ to use for its analysis, and the Energy Information Administration data is widely reported although not perfect. As we get closer to developing the rule, we can see if 2008 data are significantly different than 2007.
- Why not use 2008 data if it's available in July? ***Response:*** *DEQ and its contractor need to go ahead with compliance scenarios and economic analysis before then.*
- Considering 2007 versus 2008: In 2007 the economy was strong, so demand for oilsands as the marginal, most expensive resource, should be higher than in 2008 when the economy was weak. That would make 2007 a conservative baseline with regard to carbon intensity.
- Do we give fuel providers credit for blending ethanol into premium gasoline, if it's considered "exempt" from the state RFS?
- Commenter prefers not to include biodiesel in the baseline. Biodiesel blending was not required under state law in 2007, which is the year we're likely use for our baseline data. Would like to get credit for what we've already done. ***Response:*** *We should include biodiesel at the 2010 required blend rates if we're trying to reflect what will actually be in the market in 2010, which includes B2 statewide and B5 in Portland (Portland reports sales of 15 percent of state diesel market).*
- We shouldn't simply reward existing biofuel use. Biodiesel should be included in the baseline.
- The legislation says 2010, not 2007. Conversation ensued about how to interpret the date set in statute, whether it simply refers to the start of the program or to the actual data that must be used to set the baseline.
- Perhaps the program should require zero reductions until 2010 data is available, or should make it clear that ultimately regulated parties will have to true up to a baseline based upon 2010 numbers. ***Response:*** *We have to start somewhere, and 2007 is what's available now.*
- Will the baseline be used to figure out what regulated parties have to do year-by-year, or simply to set the 2020 goal? If the baseline is used to set the 2020 goal, then making midterm adjustments once 2010 data is available is not as big a deal.
- It seems like we're talking about really small changes, while indirect land use change is going to dominate over the difference between 2007 and 2010.
- It makes sense to leave out small volume fuels when setting the baseline (for example, electric cars, blends over B5, etc.).

- Fuel-switching almost guarantees a new vehicle, and new diesel controls are stricter, so not that worried about increased diesel particulate pollution. Don't want to encourage dog fight over natural gas supplies between transportation and electricity generation.
- Commenter prefers one standard, and agrees that co-pollutants from diesel are not an issue. Light duty diesel is an improvement over gasoline.
- Oil industry prefers one standard, based upon new numbers from CARB on carbon intensity of soy biodiesel which is not much better than petro diesel.
- Commenter does not get the point of two standards, concerned about creating silos. ***Response** (CARB): If you have one standard, then once you take into account efficiency of diesel vehicles, regular diesel will generate credits without doing anything to improve its carbon intensity. Those credits could be applied toward gasoline, and gasoline would not have to make many improvements either. If there are two standards, improvements will have to be made on each side. Credits from each can still be applied toward compliance for the other fuel category. Acknowledges there are concerns about the lack of enough low carbon diesel alternatives. Even if the carbon intensities for gasoline and diesel are the same, if you apply an EER to diesel, then regular diesel will comply with the LCFS and you will get zero reductions from the program.*
- Biggest contribution of the LCFS is stimulating innovation in the fuels market, so we want to make sure the program we design does that.
- We have high benzene content in our gasoline, so switching to diesel is not a big concern.
- Carbon intensity of soy biodiesel is a big compliance concern for oil industry.
- Oil industry representative stated that diesel vehicles travel approximately 30 percent farther for the amount of carbon emissions generated.
- Switching more of the light duty fleet to diesel would have an immediate effect on carbon emissions. Reducing emissions in the short run is more valuable than in the long term. Two standards will delay the reduction in emissions, which makes the reductions worth less.
- How will electricity providers track when electricity is used to displace gasoline and when it displaces diesel? It would be easier for them to have one standard.
- Andy Ginsburg pointed out that Oregon is much smaller than California, and has much less chance of stimulating innovation in fuels, so perhaps other factors, such as avoiding complexity, should drive Oregon's decision about one versus two standards.
- Commenter expressed preference for two standards, but sees that benefits will also come from one standard.
- Commenter expressed concern that one standard will allow credits for what regulated parties are already doing, causing lower benefit from the program. ***Response:** Baseline could be set to ensure that there is no credit for existing diesels, only for new users of diesel.*
- Andy Ginsburg asked whether committee was comfortable with a tentative consensus that they preferred one standard, but with plans to re-examine the issue once they have seen compliance scenarios.

Summary of written comments from advisory committee member or alternate June 17, 2010

- The legislative intent is to reduce carbon content in Oregon's roadway transportation fuels. That is plural. Setting two baselines provides equal incentive for diesel and gasoline to progress. One baseline obfuscates the differences between the fuels, the potential(s) for each to lower their carbon content and creates an environment where fuel choice may be as attractive as improving our fuel base carbon performance. Although more choice of distillate fuels and compression engines over internal combustion will reduce carbon dioxide emissions, it is a benefit that is in addition to the objectives of the LCFS legislation. We should use two baselines to be specific about our hopes and targets for each fuel. Using the EER and tracking gasoline conversion to light duty diesel is rife with data collection efficacy issues that we shouldn't base public policy accomplishment on. We are treating each of the alternative lower carbon fuels independently, we should do the same for base fuels. The complexity of administering a two base approach will not that difficult to do and drives innovation in each fuel. Option 3 will yield the best outcome for lowering the carbon content in each fuel. If we want to reduce carbon dioxide emissions from fuel us, then there should be an approach that encourages of incents diesel use over gasoline as long as PM et. al. is appropriately addressed and that should be separate from LCFS.

June 23, 2010 Advisory Committee Meeting

- People are buying light-duty diesel vehicles. There is fuel switching from gasoline to diesel. ***Response:*** *Right, and it would be appropriate to apply a diesel EER to the switches from gasoline to diesel.*
- The new SCR technology for light-duty passenger diesels results in diesels that are almost as clean if not cleaner than gasoline. The concern about diesel for more toxic air pollution is one of the things that is happening now with the latest rule making in California Level 3. The phase in starts at 2014 and will be fully phased in about 2020 in Oregon.
- Gasoline has benzene, so any toxicity in diesel makes the issue a wash.
- Fuel suppliers would like the flexibility of encouraging fuel switching to diesel to meet the standard, rather than having to blend low carbon biofuels or purchase credits. This might reduce the innovation for low carbon fuel.
- For tracking light duty diesel fuel use, use the Cost Allocation Study. It is a model that predicts how much revenue is going to be produced from various classes of vehicles.
- Individual companies are going to have to show compliance with the low carbon fuel standard based on the volumes of diesel and gasoline that they sell. They will generate a certain amount of deficit relative to the standard, and will have to generate credits by blending biofuels or buying credits from other low carbon fuels. So if we have general data that we know this number of diesel passenger vehicles were sold in Oregon in a given year. First we have to figure out how many of those would have been sold anyway and how many are as the result of fuel switching so they represent a reduction in gasoline. And then we have to figure out who gets that credit, individual companies?
- If you look at the fuel not the cars, from the individual producers point of view, you can certainly provide that data on the ratio of gasoline to diesel. ***Response:*** *the change in ratio could happen because of fuel economy on the gasoline side, the diesel side, a change in market share, or fuel switches from gasoline to CNG or some other fuel.*
- There are fuel economy standards, at least for heavy diesels. ***Response:*** *A change in the fuel economy standards for diesel (or gasoline) could mask the effect of fuel switching and companies would not accurately receive credits.*
- What we are suggesting is that diesel is viewed as both as a regulated fuel and as a low carbon substitute for gasoline. ***Response:*** *Yes.*
- For gasoline, if it were possible to track it I think that is what we are suggesting. We are trying to see if there is a mechanism that would actually work, or are we going to end up basically providing credit for something that is not really occurring but is actually just masked because of fuel economy improvement in gasoline vehicles.

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- Someone switches to an E85 vehicle, so goes from gasoline vehicle to an ethanol vehicle. What then? ***Response:*** *There is no change in the EER because it is the same kind of engine as gasoline.*
- Why is the reason for the switch relevant? You should just keep it at the fuel supplier level. The goal is to get more low carbon fuel out there. The reason people are switching is irrelevant.
- Here is an extreme example just to illustrate the point. In a future year we had absolutely no growth at all in the amount of gasoline vehicles. They stay stagnant, and fuel economy doesn't improve. The amount of gasoline sold stays constant and the amount of diesel that is sold goes up because there are more people and they are buying new cars and all the new cars are diesel passenger vehicles. And so what has actually happened here is just that we have had growth in the amount of vehicles and we have had no improvement in greenhouse gas emissions, but our program having not been able to capture that difference gave credit for all the growth in diesel use and made it appear as if we had reduced greenhouse gas emissions. But nothing had happened, other than population increasing in Oregon. That is an extreme example.
- If you relatively lessen greenhouse gas emissions, but you have more vehicles on the road, but the level remains the same. Relatively, you really have reduced it.
- Not if you are assuming that the diesel vehicles are replacing the gasoline vehicle, which I think we are assuming. We assume that the diesel vehicle replaces the gasoline vehicle.
- The easiest way to reduce carbon emissions is to use efficient fuel. We should encourage fuel switching.
- You want to get credit for that in the right way and I think that is the key. How do you give credit for that in the most accurate way possible? And the dual baseline may actually do that better.
- The duel baseline doesn't encourage fuel switching. It would be a benefit if we could approach the percentage of diesel passenger vehicles in the fleet such as in Europe.
- How do you parse out the credits to the individual supplier of diesel?
- I would hate to see that issue hold us up from doing something that is beneficial. ***Response:*** *You can't separate out growth from fuel switching. If we set up the program like this with no way to track clearly how much of increased diesel use was as a result of reduced gasoline use and how much was as the result of just growth. We would be providing credit for increased overall use of fuel as opposed to reduction in emissions.*
- But I think you can discreetly analyze cars, which are 10,000 lbs or less, medium duty or heavy duty separately. So once you recognize that you can, say this is what is happening in 10,000 lbs and under category today that is your baseline. And you can see what happens in the future. I think you can do the same thing with the suppliers. I don't think you look at the vehicles. I think it's a low carbon fuel standard and you look at the fuel. That is what you are measuring. You are not measuring the number of vehicles. You are measuring the amount of fuel. So if you see an increase in the amount of diesel fuels sold how do you tell how much of that is from growth in total vehicle travel and how much of that is from fuel switching?
- You would be able to see the difference in the ratio, which is what you have in the slide right there. ***Response:*** *that slide is the list of things that will not work.*
- The ratio will be affected by fuel economy changes. As gasoline cars become more fuel efficient due to the new Café Standards, the ratios change
- You calculate the impact of the Café Standards, both for gasoline and diesel, because you know the turnover of your fleet, how long it takes for it to turn over, so you know what percentage of your fleet would be in compliance with the new standards versus the old standards. ***Response:*** *If you were able to*

do that you still couldn't attribute it to an individual regulated party. I don't want you to get the impression that DEQ doesn't want to make this work. We would love to see if there is a way to make it work. We just haven't been able to figure it out yet. We have gone through the same mental exercise and if we can figure it out. If there is a way for us to implement it and be actually able to track the credits we are open to it.

- If you have 100 vehicles on the road today and there are 20 diesel and 80 gas, and ten years down the line you have 150 vehicles on the road and you've have added 50 diesel and no gas, that is a positive thing. Your ratio is lower. So, why are you having a problem in saying just stay with the fuel? It's okay, we are implementing the low carbon fuel standard, because in effect there is less carbon out there, because people are switching fuels and you can track it simply at the fuel supplier level when you regulate.
- Would the supplier be able to tell us how much light duty diesel they sold to light duty applications?
- They would be able to tell you how much they sold to a gas station.
- You answered my question that I was going to ask you and that is from the rack going out to the stations if that fuel supplier will know where that fuel is sold, light duty versus heavy duty, in a gross percentage. And those would be the people who would be looking for the credits, who would want to do the accounting to get that credit. You have the registrations of the vehicles. We know what the fleet fuel economy is going to be and you can basically do a calculation of what your overall fuel economy is based on vehicles registered.
- That's where you are trying to do your accounting for the greenhouse gas in the atmosphere. The oil industry is looking to figure out what is there in credits that they are getting. And maybe you change that credit amount or value every two or three years. But you can come up with what the fleet looks like and you can come up with what the percentage of gasoline versus diesel. And then you can value how much that additional diesel is.
- It's not exactly right, because you are going to have a statewide average for where the vehicle fleet has gone, but what you need is that at the individual transaction level so that way you know that the vehicle is sold to what type of vehicle or vehicle that was in. And all you know is the statewide average. You don't know whether the transaction was to a fuel switch.
- Well there is a gross assumption that you have to make in all of this stuff here. If you try to save us the CO2 emissions from each one of these cars, you might want to do that. Obviously, if we could monitor the CO2 output of every car that makes all of this easy, but you have to make a few assumptions along the line. And I think you make the gross assumption of what the average fleet is in the State and then you know what the amount of diesel that is being sold versus the amount of gasoline. If what is going on Europe is any indicator it is going to be pretty significant. What I'm hearing from the majority of manufacturers is they are talking 30-40% diesel introduction in the next couple of years because of the fuel economy standards. You are laying curves on top of curves. It is not a flat line that you are going to see change. You have a fuel economy standard that is going to increase and now you are trying to adjust off that adjustment.
- This single baseline seems to violate two significant principles that we operating under. 1) we want a system which promotes innovation. We've understood that that is a compromise here of the single baseline. 2) administrative simplicity. It needs to be workable and this is like grabbing something here and making assumptions and tracking this, and simplicity is the only way this thing is going to work. I think we should go through the other scenarios and options and see how they really look and how the impacts may affect these considerations.
- At the federal level, the President has put into effect Executive Orders to increase efficiencies for not only light duty vehicles for the years 2012 through 2016, but also to go beyond that and also look at

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medium and heavy duty trucks. The low carbon fuel standard is intended to shift the market away from high carbon fuels to low carbon fuels, not to move vehicles to greater efficiency. So, moving from gasoline to diesel will essentially move you from a 95 gram CO2 equivalent fuel to roughly a 94 gram CO2 equivalent fuel. The California Resources Board largely identified this and rejected the approach of having diesel fuel switching in the light duty sector because of the following. One, the objective of the standard is to bring low carbon fuels into the market. And two, it would be an enforcement nightmare essentially. But I think the former reason is of much more weight. Further, if you look at the California low carbon fuel standards lookup tables, they clearly demonstrate that they are looking at substitutes for gasoline and don't consider diesel, because it would not be in the interest of the State to consider this minor substitution for a multiple of reasons. One, it wouldn't really be a lower carbon fuel objective to go to this pathway. But, second, it would also further undermine efforts to bring in truly low carbon fuels into the market. So I think as the Department of Environmental Quality moves forward they should strongly consider the pathway that California Resources Board chose. They worked out this issue fairly extensively and I think fuel switching with another essentially high carbon fuel in a light duty market won't achieve the objectives that the state is trying to achieve. ***Response:*** *applying a diesel EER could bring down the carbon intensity of diesel used in fuel switches to 79.*

Options presented in the meeting:

Option 1: Single baseline, diesel EER applied to light-duty diesel use

Option 2: Single baseline, no diesel EER applied

Option3: Two baseline standards

- The intent of the legislation is to reduce our carbon emissions, not to encourage innovation. I think best way is Option 1.
- Option 3 gives the best results in reducing carbon emission. If we think about the overall impact or method we have to reduce carbon emissions, we know on the transportation side there is increasing fuel economy, which is already being taken care of, in things like reducing vehicle miles traveled. And then there is actually addressing the fuels piece. I think Option 3 gives us the clearest cut way to actually get both fuel pathways, and is the easiest to administer.
- We did say that we are going to remain fuel neutral, but now we are saying except in this case. I agree probably in the long run, but I still think Option 1 is the best way if we are going to remain fuel neutral and let the marketplace do what it wants to do to reduce carbon.
- We seem to be trying to base a decision on a lot of assumptions and not enough facts. I think that DEQ can do more research to figure out how to administratively administer the different options. I also think that last time we had this discussion, Andy said that we would take this discussion up again when we had the compliance scenario information together so that we can actually see the kind of the impact it had. It could change all of our opinions once we have that information available. More information that would allow us to make a much better decision.
- The overall goal is to reduce carbon and Option 1 does that the best way and is the easiest and quickest. If we encourage fuel switching to help us to meet our goal, then innovation can come later.
- One baseline would make the most sense because of carbon intensity we want to drive towards that. But administering a program and making sure we achieve the ultimate goal, there is a lot of value in achieving success and making sure it is done in the most efficient way possible. Two baselines is a lot easier. That the difference between having one baseline and two baselines isn't big enough to warrant trying to go through all the hurdles we would have to do to go towards one baseline. If we really want to get this program going and be effective and enforceable we would just go with two baselines. The need to do more research and data is a question mostly of administrative ease and the experience of doing

regulatory programs. DEQ has a lot of experience in that. I respect their position of going towards two baselines to make sure that we can get the program off the ground.

- Anything that we do on this program is going to be extremely complicated and extremely costly. Not only for the agency but for the parties who are trying to comply. But I think that Option 1, DEQ is not going to be the responsible party to have to track this stuff. If a person who it has a requirement under regulation to reduce low carbon intensity fuel on a baseline fuel, they are going to be the ones that are going to be doing the tracking. And if they want to use this as a pathway to get credits then they are going to do the tracking.
- Option 3 encourages innovation.
- Let's assume for the moment that there is no low carbon fuel standard and over the next ten years there is normal growth in gasoline vehicles and diesel vehicles, and figure out maybe there is more diesel vehicles. I don't know that most people would view normal growth as a greenhouse gas reduction strategy. I think that what the low carbon fuel standard is trying to do is reduce greenhouse gases below where we would be under normal circumstances. So what we are trying to find is what part of that change over time is attributable to people who are really switching from gas to diesel and we can't just see how to nail that down with any reasonable accuracy. As a practical matter we need to know what part of that change is actually attributable to people making the switch. And when we put our draft rule for the public and stake holders and the legislature, I don't think it is going to be enough to just say the regulated parties will figure it out. I think we really have to have an idea of how it is going to work. We don't know the cause of increased or decreased diesel use.
- Diesel light-duties have been stable for a long time and any change from now on is going to be a change in consumer habits. What is normal increase? We could pretty much say that it is flat or 1% or 2% and anything above that give the diesel guys credit for it. Maybe the petroleum industry could come up with some language on how that would be tracked or how that would happen.
- Awarding these credits is a serious monetary event. So you are opening up the state and other parties to a legal challenge, which I think is a tremendous complexity burden. To the extent possible, we do not want to be taking big estimates and guesses about how much of this is happening.
- My suggestion is that you just set up an application to the state that shows the vehicle switching from gasoline to diesel and that would be the person who would get the credit. So only that portion that really felt motivated to make the switch and demonstration of registration going from gasoline to diesel would get the credits and that would be the extent of the switching. The owner of the automobile wouldn't be the regulated party, but could trade credits on the market, or handle it through the state.
- It still doesn't answer the question of whether it was a natural switch or an LCFS switch. And if gas prices are going to increase, there would have been some natural switching over to diesel, because diesel is more fuel efficient and, therefore, you have to buy less gas. It just is really cumbersome.
- I just want to come back to language of the statute. "We want to reduce the average amount of greenhouse gas emissions per unit fuel energy of the fuels (and that's transportation fuels) by 10% below the 2010 levels." Again I think the point is that the low carbon fuel standard did not say anything about vehicle miles traveled or fuel efficiency or things of that nature, but that is does have to do with the amount of greenhouse gas emissions per unit.
- Philosophically, I'm hoping that we are all trying to get to a level playing field that doesn't try to do anything other than focus on the carbon impacts of the various transportation fuels.
- That's the question on the table, are we reducing carbon and are we innovating new fuels?

- There are legitimate, practical questions in terms of how to make this work. And it sounds like there are some hurdles. I haven't heard a fix or insurmountable problems. For me at least, it is still an old question. As Frank, for example, suggests somebody with an incentive to get the credits or whatever can figure out a way to make it work, to come to DEQ and say we've got this switching, there is this much less carbon than a business as usual case would have been and this is why we are entitled to whatever. It would be helpful, probably, putting this issue out there and saying DEQ is thinking of going into Option 3 certainly I would give incentives for those who feel they need to comply to really think hard about if we do want to do this switching, if we want it to be valuable to us how would we do it, what kind of case do we make, and are we justified.
- I think with this program, by the very nature, tracking is an essential part of how they work. And there is complexity. But legitimate greenhouse gas savings from clean diesel technology shouldn't be in this forum. So I think Option 1, while having complexities, because this program will have complexities in a number of areas.
- Our clients are the ones who supply the fuel. We are the ones who get it out to the gas stations, get it out to the farms, or wherever it is going. We track what we sell. So tracking is not it an impossible task. If you move it to any other level it becomes almost impossible, basically we are the ones who can do it. We are not supposed to be picking the fuels. And that is really what Option 3 is going to, we are going to pick the fuels. We are going to eliminate these and force you to go to other things. Now if that is something that people want, and I'm sure there are folks around the room who do, then that is fine. That is a legislative concept that can be brought up next time around, but if it is simply driving towards lower carbon emissions, then Option 1 works and we can implement it.
- Could advisory committee members or somebody from the regulated side provide to DEQ a hypothetical scenario that says in 2020 we think we could, just on the 2010 baseline say we sold X gallons of gasoline, we sold X gallons of diesel for light duty use. In 2020, we have a scenario where we sell Y gallons of gasoline and Y gallons of diesel for light duty use. And we would like to take advantage of an EER on the light duty diesel side and here is our compliance scenario. Could you provide that hypothetical to show that it is a doable, practical pathway?

- The legislation mandated lower the carbon content of the per unit of the fuel. So we are looking at on a per unit basis, we are not looking at an aggregate carbon emission from the state. And if we take that one point, it drives us, in my view, towards Option 3, because that is the option that actually delivers the fuel industries' ability to execute on lowering the carbon content per unit. And with that I would like to throw in, for other reasons that have been expressed by others, we strongly support DEQ moving with Option 3. Thank you.
- If there were no low carbon fuel standard and just the normal growth in diesel vehicles occurred and there was an increase in diesel vehicles, there might be fewer future emissions than there would have been if everybody was driving 100% gasoline car. But it wouldn't reduce the carbon content of diesel fuel, which I think is really more of the central point of this program.
- Subparagraph G of House Bill 2186, specifically calls out the fuel efficiency of the drive train. You have more than one consideration in this bill. Option 3 ignores this subparagraph.
  - Subparagraph G calls out the drive train to take it into account for electric vehicles. It is not to account for the switching from gasoline to diesel, and not to encourage that. Being involved in the bill, the intent of that section was not to encourage the switching of one type of vehicle from another. The intent was to account for electric vehicle drive transmission.
  - That is not what the language says.

  - But it really is about the carbon intensity of fuels and the best way to overall reduce the carbon intensity of the fuels. The entire pool. You take the whole thing and reduce it by 10%. It doesn't say gasoline, diesel, electricity, ethanol, or any of the above. It says take the entire pool and reduce it by 10%. So you have to take into account all of the constituents and you have to build one baseline, which is one number and it is going to reduce by 10%.
- Does an electric vehicle displace a diesel or a gasoline vehicle? Implementing a two-baseline scenario is not possible. ***Response:*** *It depends on the vehicle. Light-duty substitutes for gasoline.*
- Right now we can tell you how much we are delivering to gas stations for the light-and medium-duty markets. You have to get away from what normal switching is. The whole goal is to get better fuel out there. The fuel is here. We know the numbers.
- So again, can you present the compliance scenario with a pathway to DEQ that says here is what we can do, here are the numbers that we have for 2010? Here are the numbers that we think we can have for 2020, and if supplier "A" doesn't do it, but supplier "B" does it and maybe has extra credits and sells to "A" or whatever. But, it would be verifiable, implementable.
- If a fuel supplier blends that ethanol, they have a RIN number, and at the end of the year, EPA says show us your accounting. And they have to give them pages and pages and pages of RIN numbers to show how much ethanol they have blended from gasoline to make their standard. It is the same thing that they would have to do with diesels or gasoline or everything.
- What about when someone decreases their diesel sales?
- There is normal versus LCFS driven and I don't think that there should be a dividing line in there.
- Option 1 is the fairest. It can be implemented. There is a cost associated with each Option.
- And I think what DEQ is saying is the cost is greater with Option 1, so they are biased against it. They can't see how it would work.
- With regard to whatever the statutes specifically states or is interpreted to state, it has already been interpreted once today that we can push the deadline back to 2022 or 2024. There is clearly latitude then to consider one or two baselines. It is interesting that the more regulatory burdensome option is being favored by the regulated party, which is unusual in environmental policy. I hope this trend continues.
- Summary of our conversation or discussion today. There are a number of folks on the committee who believe that Option 3 is the best. There are a number who also think Option 1 is better. And we have heard different views about accountability. First of all, let me just ask, is this something that you need to nail down now? Or can we revisit this? Response: The problem is in the economic analysis. We are going to have to run some scenarios and we are limited in the amount of scenarios that we can develop in the economic analysis.
- The hurdle to one pool is the practicality of it and DEQ needs an alternative.
- Can fuel providers come back to DEQ and say this is how we think we can do it?
- We can talk about whether there are still some options. Look at both as we go forward and come back and see if we really do have to settle on one to be able to move forward. But we have to at least take a step forward with this for the compliance scenario.
- Looking at light duty stations, if we have diesel on some of these stations already, I don't see any reason why we shouldn't go with Option 3. That seems to make the most sense to me.

July 7, 2010 Advisory Committee Meeting

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Discussion on including a "one pool" scenario in the compliance scenarios.

- Commenter thought DEQ was still looking for input on how you would actually implement a single silo approach.
- Commenter heard that it should be one and I definitely heard that it should be 2, and there was a robust discussion about that.
- The approach of taking two silos is likely to increase the costs of compliance for within each of those silos. So it is almost a conservative approach to analyze it within two silos, because you can't have a tradeoff between the two different fuels.
    - I disagree. There is lot of things that are going to have to be tracked under a program like this.
- We are talking about scenarios and I think we need to have a scenario that shows one silo approach.
- Just so I understand what it might look like before we make any decisions. It would give some carbon intensity reduction by switching the light duty fleet from gas to diesel, I mean some portion of it. Is that where the benefit would come? So there has to be some assumption about how much of a switch would occur and what's the relative carbon intensity between those two.
- Washington is doing a single pool, and you are able to do an analysis of it. ***Response (TIAX):*** *Yes, we did two one pool analyses. We did an 8% reduction one and a 10% reduction.*
- So I don't see why we don't do the analysis and if compliance issue knows things we can also do it separately. I don't think we should borrow this, at least the questions that we have at this point, including in the analysis.
- Is the problem when you go to actually implement this, you don't know how much fuel switching is occurring. On the ground, how do you actually figure out the new amount of diesel that is substituting for gasoline.
- It is very possible to do that with more precision than what we are talking about. We know that diesel that is pumped into a car is charged tax. We know how much diesel is taxed and we know that diesel pumped into a heavy truck is not taxed.
- For medium duties you have to do an estimate.
- That's a small percentage, but it's the whole problem with the medium duties. It's a small percentage of the number of the vehicles. And we don't have good statistics anywhere, that I'm aware of, on the ones between what we consider light vehicles and heavy vehicles. And, in Oregon, it is between 10,000 and 26,000 pounds.
- So the presumption in that is that all future light duty diesel sales substitute for gasoline.
- No, above the business as usual.
- So does business in usual in Washington then project light duty diesel as increasing at some natural rate. ***Response (TIAX)****: We did not adjust the light duty diesel populations at all. It stays the same. It's just that it gets a credit in the one pool, and if it's separated it doesn't.*
- But there is no some sort of middle assumption that there would have been some Normal diesel sales that would happen absent a low carbon fuel standard anyways.
- And just the other projections that we are doing, we are going to project what the base case is and what would happen in 2022. Yes, there would be additional diesel sales that would happen.
- And I certainly don't expect you to take my word for it, but what I'm suggesting is that DEQ go talk to the people who run those programs to see what kind of data that they can produce. I mean I've been working with it for 30 years, so I have some idea of what it is, but you know there are the folks at the

fuels tax branch and you would probably need somebody from DMV and, again, I would encourage you to touch base with (inaudible). He's sort of the guru of making estimates from all of this.

- So if I'm hearing it right, there could be in the base case a projection of diesel sales that would happen absent of low carbon fuel standard? Then there would be additional diesel sales and scenarios and the difference gets a low carbon credit, but then when you actually go out in the field and try to document how much volume of diesel fuel belongs in the low carbon fuel piece, not in the base case, how do you distinguish?
- Same way that you just did it, is you take here's the diesel that is doing into light vehicles, project that to 2022, here's the diesel that is actually sold in 2015 and if there is a difference then that diesel gets credited.
- A projection is fine for modeling, but it would be difficult to use for compliance, which needs to be based on actual data.
- If a guy is driving a gasoline vehicle and the next car that he buys is a CNG or diesel, which would be either way, then how would you differentiate that?
- Sounds like Washington's scenario assumes that all future light duty diesel sales substitute for gasoline. They didn't try to parse it between these would have been some increase in diesel fuel.
- There are two issues. One is how you measure compliance and the other is what are you modeling, two pools or one pool. So we kind of mixed those two things up here in this discussion. We don't have resolution on how you comply.
- Well what I was hoping was that we could still allow running the scenario or running numbers that would allow you to say you get some credit for the switch, without having to decide is it actually implementable.
- I'm wondering has Washington numbers been run already, or is this a draft of them. Is there a huge difference between one silo and two silos? ***Response (TIAX):*** *In the one pool approach, the diesel dominated. I can't remember the percentage of the reduction, because the focus of that compliance scenario was to use in-state production and there is a lot of projected canola biodiesel. Because they have a lot of biodiesel production capacity in Washington and a lot of potential canola production. Their one pool scenario was more or less a biodiesel heavy scenario.*
- So what this tells me is that even if there were not a big difference in cost that the likely difference in cost is that a one silo approach is less expensive if administrative details can be dealt with, in terms of a market transaction to the regulated parties the one silo approach may be cheaper, at least based off of how the Washington state set up their system. So if we are looking at very conservative analysis of what the impact of this program might be on regulated parties then a two silo approach may be the more conservative for us to take. So I don't see anything wrong with just, if you want a conservative analysis of what the impact might be the regulated parties to get forward with what we've had to give them.
- Each of these scenarios are going to feed into REMI, is that right? ***Response****: Right*
- Why are we afraid of getting the information on one vs. two baselines? We haven't chosen it, but at least we could make an informed decision.
- **Chair:** Certainly we are hearing some strong requests from some members to run a scenario with one pool. We hear a strong objection from other members that say, no, more conservative approach is appropriate. DEQ is saying they are concerned about implementation so they don't want to run scenarios that aren't likely to be possible. I think they don't have a strong opinion one way or another. I would like us to clear out the information and move this onto a decision-making body, because ultimately, as this committee, we aren't going to craft the rule. We are going to make recommendations about the rule, but

we aren't going to decide about the rule. I liken us to be a clearinghouse for information and for opinion and then move it forward. So that tends not get us to closure, but I don't think we can get to closure on this one any ways. Do you at DEQ have a strong objection to running another scenario? Are you concerned about costs and resources and time?

- There are some real barriers to light-duty diesel that you are not taking into account. We have less light duty diesel models available than we do flex fuel vehicles. It's going to take a long time to get those out. Also, you have the same problems with diesel that you do with E85, because there are not enough diesel pumps available. They are going to have to start adding pumps. I think it is a more complex issue than you are probably really thinking about at Administratively approving adding a carbon intensity this point.
- You are probably aware that legislature in February suspended the biodiesel mandate for next winter because of the problems we had last year. Once we get to renewable diesel, we won't have those problems.

6. Low Carbon Fuel Standards Compliance Schedule

January 27, 2010 Advisory Committee Meeting

- It looks like we're considering a similar trajectory to California. Is Oregon starting at the same place with regard to market penetration of alternative fuels as California? ***Response:*** *The fuels assessment will help the committee consider what is reasonable and feasible with regard to expectations about low carbon fuel volumes. All of the program elements interact with each other: exemptions and deferrals, compliance schedule. A deferral would push the compliance schedule back if our projections turn out to be* unreasonable, for instance.

April 15, 2010 Advisory Committee Meeting

- I would be interested in hearing from the fuel suppliers about the decision to move the date to 2022. That means that there has to be a larger reduction in gross terms, because you have growth for two more years if you are going to reduce it to 2010 levels. Therefore, it will have an impact on the programs. It should be a whole committee discussion **(Issue was discussed on June 23, 2010)**

June 23, 2010 Advisory Committee

- It makes sense to use the same horizon year as Washington (2023), because 90% of our petroleum fuels come from there. ***Response:*** *We do not know if Washington is going to move forward with a LCFS. Assuming they do, we do want to be as coordinated with Washington as possible. But the LCFS program does not involve changes in blending at the refinery or pipeline. Biofuels are blended at the terminal or lower in the distribution chain. Therefore we are not tied to Washington, as we would be on other types of fuel standards.*
- Will the baseline year stay at 2010? ***Response:*** *Yes*
- Renewable diesel comes from a refinery – so it would be important to be on the same timeframe as Washington. ***Response:*** *It is a good point you are making. But different horizon dates for each state provide a more flexibility for the refiners, so they won't have to produce enough for both states on the same schedule at the same time. A difference in timelines between WA and OR does not change the type of fuel refineries need to produce. When we go to rulemaking, we can look at what Washington is doing*

and consider aligning the actual horizon dates at that point. What we want to do here is look at a ten-year phase-in schedule.

- The basic principle of the program is to reduce greenhouse gas emissions. Transportation is about a third of our global warming pollution, so postponing the horizon year from 2020 to 2022 makes a significant difference. The legislature said 2020, and knew it would take awhile to implement the rule. We need to leave the option open to have a 2020 baseline so we can sync with California. The biggest perceived hurdle is the technical feasibility, and biofuels will be able to come on line fast enough to meet a 2020 horizon year. If the economic and compliance scenario work is completed for 2022, there will be no information to support a 2020 horizon year.
- We should have a compliance scenario with a 2020 horizon. There is enormous public support for reducing pollution and breaking oil dependence. 2020 is a workable horizon year and the benefits of this program need to be brought to the state as quickly as possible.
- Can we decide a ten year period is okay, and then decide which ten year period later? ***Response:*** *Everyone is making good points on this. I don't think we are going to be doing the economic analysis showing compliance with 10% at different horizon years. Forecasting oil prices, etc. is tied to a specific year. There are already many variables and we need to have the contractor only use one specific horizon year. This program is intended not be an incremental change, but to be really a significant change. In order to get these kinds of significant changes you really need to back in your technology to give the companies time to innovate. The original vision with HB 2186 when moving through legislature is that we have rules adopted by the end of 2010 and that is just not going to happen. It's going to be more like the end of 2011 or later and so if we compress the compliance schedule it could raise the cost of the program. People will have to develop advanced technologies on a faster schedule and that always ends up raising the price of the program. So if we really want innovation, we just have to be a little bit patient. So like everything else we are deciding in this committee, all these decisions are inter-related. We could have an eight year horizon, backload the schedule more and have everything happen in the last two years and you would get the same affect, but I think that could be also a negative. My recommendation would be that we spread the difference 2024 and 2020 and just go with 2022 for the analysis and then when we actually get to the point of proposing rules we can look and see what makes sense right now given what Washington's done and given where all the litigation is, etc.*
- Our assumption is that we would have at least proposed rules prior to the 2011 legislative session. ***Response:*** *We will have at least a draft rule prior to the 2011 legislative session.*
- Regarding 2020 vs. 2022; California is going to drive the technology, not Oregon. Because of that, 2020 is the correct date for Oregon to use because it syncs with CA.
- We need some analysis on 2020, because it will be difficult to consider if there is no analysis done on that timeframe. If there is analysis done on 2020, we can then consider a range of 2020 to 2024.
- How difficult is it for the contractor to say that delaying or expediting the rule by a year or two will cost more or less? Is it like re-running the whole model or something they could do at low cost? ***Response (ODOE):*** *It would be both. It depends on what variables you are choosing. There are main variables and variables that are changing the direction of the impact. So some key variables have to be designed on business as usual and the other alternative cases on the different scenarios. If you are looking at changing the time line of the modeling and year of the horizon year you are looking at potentially having to relearn how the alternate scenarios change under a different horizon year. The base year will not change, but you are looking at potentially new interpretation of scenarios or your understanding of these changing costs across the different sectors or the changing baseline across the different fuel availability, the change of the economy, and these are key effects that you want to measure.*

- It seems to me that the biggest factor between 2020 and 2024 isn't that there are going to be huge spikes projected on any of the markets, because generally when we are projecting what is going to happen it is just a steady trend that we project based on historical data. ***Response (ODOE):*** *Not necessarily. If you look at 1990 projection of natural gas or 2002 or 2020 it is a wide scaling range. I cannot assure that it is 2010. Steady trend is what is done in economic analysis to allocate or to show the best case reasonable, so you know what the main dominant potential set of prices to be or likely impacts to be. We look at main variables to adjust these. AAA does this all the time with fuel prices and we go by that.*
- If we have five different compliance scenarios and we are projecting how much of the different types of low carbon fuels are going to be available in a given year that is going to determine the cost. And so if we compress the compliance schedule then we have to also forecast what the affect is going to be on the supplier of the low carbon fuels, and, for example, construction costs for ethanol plants to be built on a shorter schedule. A whole new analysis would be necessary. And then we run the model. ***Response (ODOE):*** *Yes. And you haven't even talked about sensitivity analysis.*
- Is there a way of just using the sensitivity approach rather than re-running the whole thing for 2020? Could we run it for 2022, and ask the contractor to give us an assessment of how the prices would change for 2020? ***Response (ODOE):*** *Answering this would require some work with the contractor.*
- This is a really important decision. What you said earlier is that we would do 2022 and then we would decide what the rule date is when we get into the rule making process. It sounds like we really don't have the opportunity of doing that if we don't have the luxury and infinite amount of money to pay the contractor to do multiple scenarios. Then we really need to pick a date and that becomes the date. And it also sounds like it would be very helpful to discuss this with the contractor to see what kinds of things they think they might be capable of doing and at what cost.
- Resolution and compromise means that nobody is entirely happy and it strikes me that the folks who will ask to stick with 2020 are not going to be entirely happy with 2022 and the folks who would like to see this slowed down with a horizon year of 2023 pr 2024, are not going to be entirely happy. 2022 seems like a reasonable compromise that works, given the DEQ limited budget and having to pick a date. I would hope that we would hear more from the contractor, such that we could say we can have them go forward with that date, but know that if we moved it up this would be the consequence and if we moved it back this would be the consequence. It sounds to me like DEQ is taking a middle of the road approach that is workable. So let's give them that chance, certainly until the next meeting, to talk to the contractor.
- The converse is that we are stretching out the timeline, and therefore, economic and environmental benefits are diluted.
- The larger issue is the greater environmental benefit to the state. ***Response:*** *You are right, where we started was that we want to get the benefit of the program, but we are aiming at a ten year phase in schedule because of the amount of time it is going to take to get the rules adopted. A ten year schedule takes us to 2022. If we compress that then we are probably going to make the program more difficult to implement because the compliance schedule will be compressed. The only reason we are talking about the cost of the economic analysis was just the suggestion that we run the analysis for both years. We probably can't afford that, but that is not the driver here. The real driver is what is a logical phase in schedule for this program? It is a combination of the horizon year and then that curve between the base year and the horizon year, which we have all talked about as a back loaded curve where most of the reductions happen in the last several years. But we haven't actually agreed to or nailed down that curve yet. So, as with everything in this committee these are all decisions made that affect each other. But obviously you could have a 2020 compliance year and then change the shape of the curve so it is even more back loaded. I would propose 2022 as a good date, both from the renewable fuel standard and at*

the federal government level. It ties all of the actions of Oregon into that program so that as all the fuel companies move forward to change their fuel mix to comply with the 36 billion gallons that all of that would happen in parallel here in Oregon. The other thing that happening is California is discussing the LEV Program, changing all those emissions standards. The year of that full implementation is 2022. So you are going to have all of these new vehicles to comply with this new program happening in 2022. It just seems that you have the stars aligning around 2022.

July 7, 2010 Advisory Committee Meeting

- Regarding the 2022 horizon year: we don't have consensus with the committee. So 2022 is our analysis year and we are going to do our best to see if we can get any kind of comment about what we would expect to be different if it was 2020. We can't afford to do the analysis for both years, but I would like to make certain that we keep track of things that would make a difference. We can comment on that it would be substantially similar in 2010 and 2020 would be different. I know that Washington is analyzing 2023. So we will be able to know from their analysis what those kinds of assumptions might make. But to the extent we can bring any information in the final report, even qualitative, I think that committee members would appreciate seeing that affect of that horizon.
- I appreciate the comment and we will work to find a way to provide some sort of background analysis to explore what 2020 might look like. We can go back and compare other state analyses or just a review to show 2020. So I don't know if it is through this process, but through another process.
- So in our analysis, the percent reduction would be for 2020 at 6½%. To meet a 10% reduction in 2020 I presume would have some effect that we can at least qualitatively describe. ***Response****: After we finish this whole report, sometime next spring or summer we will be doing rule making and if at that point we propose the program that goes with a base year of 2010 to the horizon year of 2020 or a base year of 2013 and going to 2023 we are not precluding that decision by analysis on these years and I think committee members would like to see if there is any information that we could keep track of as we go that would help us know if we did that at that time is that going to make it significantly more expensive to implement the program or less expensive. So we may just be able to qualitatively say talk about how they might be affected by an earlier or later horizon year. If there is some way to qualitatively note that I think that is what the committee members were asking for.*

- An earlier completion date for the LCFS program would require a different compliance slope. ***Response****: Our original legislation talked about 2020 and DEQ is thinking 2022 just because of the time it takes to do the rule making and the advisory committee. So it's still a 10-year phase in and advisory committee members have asked what would it look like for 2020, which would be an 8-year phase in. We would have a different curve. So with that in mind, if you can keep track of any qualitative things you might say about the cost of the infrastructure and so forth, then we could at least get a sense of if we wait or were convinced to adopt it within 2020 horizon year, how that would affect the economic analysis.*

Summary of written comments from advisory committee member or alternate December 1, 2010

- The state legislature adopted the LCFS with the intention of reducing the carbon intensity of fuels 10 percent by 2020. This standard would have a significant volumetric decrease in global warming pollution by 2020. DEQ should make every effort not to let the compliance schedule not to slip past 2020. If it is deemed necessary to delay the full 10 percent reduction past 2020, then the projected volumetric reduction should be made up in the subsequent years. This would assure that the LCFS achieves its desired impact in meeting Oregon's climate challenge.

7. Updating or Adding to the Carbon Intensity Lookup Table

Summary of written comments from advisory committee member or alternate November 6, 2009

- Oregon should look into encouraging sequestration of carbon through bio-char production.

December 3, 2009 Advisory Committee Meeting

- Carbon intensity analysis should not overlook the possibility of improvements in conventional petroleum fuels.

May 20, 2010 Advisory Committee Meeting

- For landfill gas, are fugitive emissions represented in that carbon intensity? ***Response:*** *we will research that and get back to you.*
- For DEQ, is adding new pathways a workload issue ? You want to only go through that exercise for people who are going to be serious about it and produce commercial quantities. ***Response****: Yes.*
- For funding purposes, a pilot-scale producer needs to be able to get a carbon intensity number for their commercial-scale facility. ***Response:*** *DEQ would be able to establish a new carbon intensity number for a small-volume fuel producer, but we would not be required to. If we saw a promising new fuel we could still go below these thresholds and establish a pathway. the fuel volume would be based on the capacity.*

  But the producer would be relying on DEQ having enough time. Is there a way to provide an administrative alternative to acknowledge a producer's carbon intensity analysis?
- For the new fuel pathway, the fuel producer would do a GREET analysis, and DEQ would be responsible for reviewing that application and validating it.
- Carbon capture and sequestration (CSS) is included in California's rule to decrease the carbon intensity if a high carbon intensity crude is used. CSS it is being used for oil production enhancement in a number of places and at electric power plants. Commenter is concerned about how CSS would be included in the lifecycle analysis. This will addressed this in the fall in detail. But to the extent that any CCS is directly related to compliance with cap and trade it should not be credited towards the LCFS. The low carbon fuel standard is not a policy tool to encourage carbon sequestration.

October 14, 2010 Advisory Committee Meeting

- When you come to the market with a fuel with different carbon intensity you will have a natural incentive to want to establish a new pathway. If you have a fuel with a higher carbon intensity then you don't have that incentive and will want to try and hide the fact. That is one reason the significance threshold is geared towards improvement. To the extent we can account for Canadian tar sands or account for countries with high carbon intensity we can use the precautionary principle of this is how much there is and not try to get too much finesse. If we provide as many numbers as possible in the beginning, the market can adjust itself.
- The way proposed all along is that gasoline has a statewide average number as does electricity and diesel. No mechanism exists for individual companies to get their own numbers in the table.

- This is an opportunity if processes change to lower CI. This is a periodic snapshot of what is actually coming into Oregon.
- This does not reflect the refining processes, but crude production.
- If we update the whole lookup table it would take into account the whole process.
- Seems like a three year cycle quite a bit of uncertainty about what the CI will be every three years and it would be better to have an established CI so that if you change your technology and get a better CI then you create a new pathway but have the certainty of an established CI.
- Do we want to update the whole table? ***Response***: *Not unless the pathways change.*
- For Option 2, are we calculating the mix of petroleum fuels? There is no incentive for an individual company that is reducing CI of its production and refining process because whatever good they accomplished everyone else gets credit for it. Since it is more administratively simple, but only makes sense to do if we don't expect the CI to get big between the companies. If it gets large, it could be problematic. If the difference is modest, it is probably a simpler way to do it.
- It is mixed together now, the CI for petroleum represents an average. We haven't gone where individual companies can establish their own boutique CI. If it ever happened that individual producers started deviating we can visit the system; but, having average is easier.
- Is it realistic to expect that petroleum companies will have a mix of high and low carbon crudes, or specialize in low carbon?
- Different companies get their fuel from different places, so they have different values currently. We don't know what individual CI is so if they changed we wouldn't know. (it is a basket)
- Unintended consequence of the actions here is that companies might wait to introduce lower CI products.
- A compliance schedule goes for ten years, if at year three we determine the average mix of crude has gone up by two points, we have further to go. The next three years we check it again we are keeping up with it. You could say it would be better to do it more frequently but in the end we still need to get at the 10%. It may be more of an administrative question what the frequency of the reassessment is.
- Main question is should we do it as a pool and keep adjusting the basket or separate it out? Are we trying to create an incentive for oil companies to decrease the CI or create a disincentive to increase it. Or are we trying to get low carbon fuel into the market.
- In favor of keeping it as a basket. Companies are tied into a portfolio of the fields they have which are leased. New fields don't come on line that often. If we are trying to reduce carbon, shouldn't we r treat petroleum like we are treating electricity which we decided is a basket. If too much of a burden every three years, do it every five years.
- Process of updating the CI is not what is burdensome, it is the rule making process.
- Crude shuffling would occur when the table is changed on a regular basis.
- Oregon is attempting to be a model for other states to adopt similar programs. Some of this on crude shuffling problem will go away when more states adopt. We should not worry about the shuffling in the near term and use the program to leverage long term gains in greenhouse gas reductions.
- Whatever system we set up needs to apply to all because the same variability in feedstock and transportation. When you put in the same basket the bad actors hide behind the good guys. This has an impact on the credibility of the program.

- Can Oregon regulate this when there are not producers in the state? Should this go forward, crude should be treated as crude and not penalize the high intensity crude. Calculate on the fuels from the refineries. Option 1A is better.
- Oregon is a small player, fuels will be shuffled to our neighbors not necessarily China or around the world.
- At a previous meeting, the committee had discussed allowing a new fuel pathway for refinery efficiencies. Options 1A and 2 do not include this. Does WSPA have any comment on that?
- Question: Is shuffling calculated in the baseline. ***Response***: *It is since transportation is a factor.*
- Option 1A appears to be rather neutral in terms of causing shuffling and will keep things simple in the pool. Option 1B would be the worst in terms of incentivizing shuffling but is the most accurate. Option 2 is a kind of compromise between the two.
- Fuel shuffling won't occur because of Oregon's rule, we aren't that significant in the market. California is the most advanced and every time we try to do something different that our neighboring states we make it more difficult on the industry. Doesn't it make more sense to mirror California and Washington?
- In some ways Washington may be looking to us because they aren't in rulemaking.
- We keep talking about crude, but the process of carbon intensity needs to apply to all fuels because you do have a system set up with rewards and penalties.
- Petroleum is asking to be treated differently.
- Ok with the pool to start with but ultimately but we are looking at how the fuel changes in the future by dis-incent more carbon intense fuels and incent less carbon intensive fuels. Not taking that into account will cause gaming in the petroleum sector. Electricity was a very unique sector because CI changes dramatically from utility district to utility district.
- Clarification of 1B, only address a new source or new process for refining the crude. Increases from existing HICF would use the existing table. There can still be sizable increases or decreases from existing sources that will use the old number.
- We have established that our market power is very interesting, we aren't going to cause shuffling. Option 2 makes the most sense by seeing if the industry around us, sending product into our state, has it changed.
- Table of all the pieces of the program and when they are updated. Does the schedule include CI updates? ***Response***: *No, we will add it when we conclude what that timeframe will be.*
- Treating crude as crude without continual analysis probably is not the right thing to do.
- Ideally, like to see all liquid fuel sold in Oregon have a pathway. A basket is less complicated. If we do have neighbors around us like CA that are getting a lower CI value because of the process there, shouldn't there be a mechanism that allows for buying from those producers?
- If there is a pathway established in CA, we should use that number as a default, is that what you are suggesting?
- We aren't creating any numbers for petroleum, just biofuels.
- Using 2009 data from Canada DEQ estimated what is coming to Oregon through WA and UT.
- Needs to be some ability to piggy back on our neighbors as they learn. Pick one of these options but have the ability to adjust down the road.
- Does it make sense every three or five years to update the basket to keep it accurate. We are trying to get from 94 to 86, we aren't going to get as far as we want, so we should check.

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Mark Reeve, Chair, summarized the discussion on high carbon intensity crudes at the end.

- No perfect way to do it
- Trying to get overall carbon intensity down over a ten year period
- Dealing with the fact that our state is a market taker not maker
- In an ideal world without a lot of complications and differences in the petroleum world we should not have a basket. Don't think we are close enough to that ideal world . We need a simple approach which is starting with the basket.
- Option 1B isn't particularly attractive particularly with what CA is doing, but if sub-pathways are developed we need flexibility to change the basket as well as bring folks on along side.
- Certainly some version of one is preferred by others.
- Periodic review, over three years is favorable.
- We need to document diversity of viewpoints; there is no right or wrong
- If we update the pool periodically, we are counting for any changes in the crude side of it.
- If making assumptions that carbon will be higher in the future, the interim updates will show that. The end number does not change.
- If we update the average every three years, the actual shift to a high carbon fuel could have happened in year one, there could have been a compliance obligation based on the baseline. More frequently the table is updated the better.
- Don't see us going retroactively back

Summary of written comments from advisory committee member or alternate December 1, 2010

- High-intensity carbon fuel, such as Alberta tar sands, need to be carefully tracked and reassessed. Otherwise, there is a strong potential that the LCFS will lose ground in meeting its goal to reduce the carbon-intensity of fuels 10% by 2020.
- Energy Economy Ratios (Drive Train Efficiencies) for NGVs. Clean Energy made DEQ aware of the CARB decision to apply a 0.9 energy economy ratio to heavy-duty NGV fleets largely due to legacy vehicles in operation throughout the state. Oregon, unlike California, does not have a significant legacy fleet of NGVs to the same extent in operation, and therefore would ask that DEQ consider a 1:1 EER for HPDI systems and a
- 0.94 EER for spark-ignited systems. Based on data provided by Westport Innovations (engine manufacturer of the ISL-X) and Cummins-Westport (engine manufacturer of the spark-ignited ISL-G) that will be provided in the appendices, we believe the proposed EER for each system would be reasonable.

8. Credits and Deficits

December 3, 2009 Advisory Committee Meeting

- Oregon may generate business opportunities by incorporating the ability to connect to voluntary credit markets. Trading credits should reduce costs of the programs, since it will give regulated parties options for how to comply.
- Is there potential for secondary markets (i.e., investment firms) to evolve to pool individual charging station owners to sell credits?
- Market for credits under LCFS will not be a "free market," though, since it will be required by a government regulation, so assumptions about transactions only happening because they are economically beneficial to both parties would not apply.
- Does it make more sense to calculate credits at the point of sale for an electric car, because there would be only a few car dealers that would be regulated, rather than at the point of car ownership? ***Response*** *(PacifiCorps representative): LCFS credits should be allocated according to fuel use. As electric vehicle use grows, there will be incentives for utilities to install separate meters and charge lower rates for charging during off-peak hours in order to lessen the impacts of load growth.* ***Response*** *(CARB): The LCFS should reward entities that pay for fueling infrastructure by allowing them to claim credits.*
- If Oregon does not have a system outside the LCFS for selling credits generated within the LCFS (as California has under AB 32), then there is not as strong a reason for keeping the credit revenue with the electricity providers. ***Response*** *(PacifiCorps representative): If LCFS credits become substantial sources of revenue for the utilities, it will become an issue for the Public Utilities Commission.*

January 27, 2010 Advisory Committee Meeting

- Megajoules as a measurement unit reflects the generation of heat which is different than energy applied to the wheels which is horsepower, signifying how many times the wheels turn.
- Could unlimited banking of credits dilute the effect of the program in later years? Conversely, getting more GHG reductions early on is helpful for fighting climate change.
- It could become a political factor if a big credit surplus builds up.
- Under the Renewable Portfolio Standard, credit banking encouraged early wind investments and allowed investors to be nimble and manage risks.
- Is there any problem with a business-to-business agreement promising to sell future credits? ***Response:*** *No, but credits for fuel not yet produced could not be used for compliance purposes.*
- If the concern is high credit prices, then capping the price could be a better option because it will be difficult to define "third party."
- It may not be legal to exclude third party participants, but a good alternative may be to not allow unlimited banking by parties without compliance obligations.
- There is also a risk that a regulated party could sit on a pile of credits (hoarding).
- Would 2015 sunset mean that credits would expire? ***Response:*** *Yes*.
- It would be useful to reframe the question: Is there any value to third party participation, and if so how should they be constrained?
- Potential regulated parties are very nervous about speculation.
- The rules could require registration of third parties.
- SO2 market-based program lets parties buy credits after close of compliance period and before the compliance filing is due in order to "true up," giving an extra couple of months to ensure they are not out of compliance. ***Response*** *(CARB): This approach could add complexity to the LCFS credit accounting*

- Suggest that the rules don't contain an absolute prohibition on credits from other programs, maybe say "not allowed at this time"
- Broadening sources of allowable credits could allow the program to achieve the maximum CO2 reduction possible.
- ***Clarification*** *(DEQ): Oregon can't control the terms of a Congressionally-passed program, but does have the choice about whether to allow offsets to be used within the LCFS program.*
- Could credits be traded with California and Washington's LCFS programs?
- Perhaps Oregon land use programs with impact on transportation emissions could generate LCFS credits in the future.
- Oversight would be needed for multi-state trades to prevent double-counting
- We should use whatever information we can from the RINs in order to make our administration simpler. ***Response*** *(CARB): California requires RINs to be reported, and plans to use it to double-check the information submitted for compliance.*
- Oregon could end up building a lot of complications and limits into the LCFS, making it difficult for regulated parties to comply and encouraging fuel shuffling between states.
- Railroads fear price increases if their fuel distributors can't sell blends to them, but have to make up for it by buying additional credits. ***Response****: This is one reason why the choice of who has the compliance obligation matters; in this case, higher up the distribution chain is better.*
- There is some concern about large amounts of banked credits building up in early years
- There are concerns about protecting investments made in low credit fuel production capacity

Summary of written comments from advisory committee member or alternate December 1, 2010

- LCFS credits can be banked indefinitely without expiration. Clean Energy supports DEQ's determination that credits can be banked indefinitely without expiration as this provides a regulated party with the opportunity to save credits for future compliance purposes or the potential of selling a credit at a reasonable return when the market is not overly saturated.

- Low Carbon Fuel Credits that are banked should not be compromised. Clean Energy disagrees with DEQ's current position that credits generated and banked under the LCFS program would be subject to an adjustment of carbon intensity at a future date by DEQ when all credits generated under the program and sold during the same period of time would not be subject an adjustment by the DEQ. Clean Energy believes that the DEQ must maintain fairness across the board and DEQ's current policy would harm those who bank their credits.

- Further, Clean Energy believes that DEQ's position will also create an early liquidation of credits in the market as some assumed low carbon fuels face a potentially significant adjustment in carbon intensity when indirect land use change (ILUc) factors are applied. In fact, a potential unintended consequence of DEQ's current approach may be that fuels vulnerable to indirect land use change (ILUc) may oversell their product into the market, falsely inflating the market's performance of low carbon fuel penetration only to discover that the real benefits are substantially less, and those low carbon fuels that provided a true carbon benefit to the program are harmed as the value of credits will have been diluted. A fairer approach by DEQ would be to apply the ILUc numbers that CARB has adopted and adjust credit values on a prospective basis once there is a broader agreement on ILUc values in the regulatory community.

- Finally, Clean Energy is very concerned that DEQ's position to postpone the adoption of ILUc factors at the program's implementation and decision to make an adjustment to carbon intensity once ILUc issues are resolved will create a disruption to the market at or near the time DEQ will be seeking re-authorization of the LCFS by the Oregon State Legislature. This
- Clean Energy will most certainly provide those regulated parties who are the focus of the regulation fresh allies to oppose re-authorization as many who invest in providing low carbon fuels may find that their fuels do not provide the anticipated carbon benefits. Clean Energy strongly urges DEQ to consider the longer term consequences of its actions, especially actions that could create crisis right before the state considers the longevity and viability of the program. In fact, the uncertainty caused by this potential change could derail the entire program.

9: Buying and Selling Credits

October 7, 2010 Advisory Committee Meeting

- Any info we collect is public information unless the entity providing the information can prove that it meets the requirements of Oregon's a trade secret law.
- Could you give us an example of what information would be used to verify a credit? ***Response:*** *Buyer and seller would both need to report the credit transaction, and respectively, who they sold or bought it from. There are several pieces to a "valid" credit. First, DEQ needs to approve a carbon intensity number for the fuel. Next, a regulated or opt-in party needs to demonstrate (one-time) the way that fuel gets from that producer to them. Lastly, invoices for fuel sale would show the volume of fuel that had been supplied to a retail facility or end-user.*
- You cite administrative burden as a consideration, what types of information (analysis, audit, etc.) would create such a burden? ***Response:*** *To show a credit has been generated, a regulated party could show us how much fuels sold and carbon intensity, and DEQ would verify invoices.* ***Response:*** *There are two parts to this- at the sale level, there is the need to verify the number of credits bought match the number of credits sold, verifying the transaction. Then there is a second kind of verification that needs to happen, where DEQ would verify the number of credits generated based on the fuel type, pathways, etc.*
- To the extent a credit becomes a sort of currency, then the currency has to be trusted, and there has to be a process to verify the value of a credit being sold. ***Response:*** *So the question there is does the credit need to be verify before the credit is sold, or can it be verified at the end of the compliance year?*
- There's a bit of a trade-off here, where the less verification you do, the more transparency is needed in the market to self-regulate itself. The first approach concerns me because it doesn't provide the market players enough assurance that the credit is worth what the buyers and sellers think the value is. I would favor an approach that increases transparency that keeps the regulatory burden low.
- A utility can get Renewable Energy Credits now, would those be essentially the same thing as LCFS credits? Could they apply for these instead of the RECs, or do both at the same time? ***Response:*** *These are different because some renewable won't have a very low carbon intensity electricity footprint.* So they would qualify for a REC but not for an LCFS credit? ***Response:*** *Remember that the LCFS program*

is going to use the statewide average for electricity, so it will be different from the REC. The same thing would go for RINs – someone could sell the same RINS with the same fuel as LCFS credits, because they are different programs with different intents. So they could be sold to different programs, theoretically? ***Response:*** *No, because the credits in each respective program represent very different things. Remember that the 10% reduction from baseline, we're talking about all reduction, no matter where it comes from.*

- So if credits are not fungible, could you choose to sell them as a RIN or a REC or a LCFS credit? And if you can do that and the programs are significantly different on the market, that could create a shortage or a surplus, depending on how that worked? ***Response:*** *A utility that's buying or selling RECs that is separate from electricity sold for transportation and any associated LCFS credits. Credits would not be fungible, and could not be double counted.*
- So if credits are not fungible across programs, you have to take into consideration the market for those as well as for these to see how the market is going to respond and whether there is an adequate supply.
- Our example is slightly different in that we will be producing RINS, and at the same time producing credits under the LCFS program. The credits are not fungible, but the same gallon of fuel will be generating credits under two different programs, but the credit value under the LCFS is not competing with the RIN value.
- In your case I agree, but in Todd's case, it does have an effect.
- It depends. I'd rather sell credits in the transportation sector rather than in the electricity generation market due to the economics. The economics favor the transportation market.
- This is projected to only be about 5% by 2022 and it's not a large part of the mix in trying to meet the standards as currently calculated, and then this problem is a smaller percentage of that 5%. So what it's worth, the program won't be jeopardized by RINS and RECS. ***Response:*** *I'd like to go back to the discussion about option 1. If a biofuel manufacturer were to sell a LCFS credit twice to two different buyers, under the minimal DEQ involvement option, presumably the buyer would be able to review the records of the seller to assure that the pathway and carbon intensity had been approved for the fuel, and DEQ would expect that level of diligence on behalf of a buyer to validate the carbon intensity, but they wouldn't have any way of being able to determine whether the seller sold credits to other buyers, and at the end of the year during the compliance reporting period, DEQ discovers that a company sold more credits than they actually generated during that year through production. So the selling company would be in violation, but what about the receiving company that purchased the credits in good faith thinking they'd bought a valid credit, but in fact that credit had already been sold to someone else? What would happen to them under the minimum involvement case? Would they theoretically have to make up the value of that credit later but wouldn't necessarily have to pay a penalty for being in violation? Could such a scenario be addressed under option 1, minimal DEQ involvement?* ***Response:*** *We could require them to buy more credits within the next three years to achieve the desired greenhouse gas reductions. Or we could hold the buyer harmless and require the seller to make up the invalid credits they had sold.*
- Even under option 1, there could still be a market where credits are bought and sold that is facilitated by DEQ, where regulated parties notify DEQ of what they've sold and that information is posted, without DEQ verification of each transaction, allowing for some transparency in the market with minimal DEQ involvement.
- The last thing we'd want to do is set up some sort of secondary insurance market where companies need to insure against the market not working the way it is supposed to.
- Do you think that this is something that DEQ could fairly easily have a third party contractor provide the verification services and act as a pass through in terms of the cost? Do you see that as a potential

scenario? ***Response:*** *Yes. DEQ has programs like that where there is a pay for service. It is difficult to staff for something like that because you don't know how many requests you are going to get, and hiring a contractor to manage it is one way of addressing the issue.*

- Would it be possible the collective regulated parties could contract with a firm and they would facilitate the process? ***Response:*** *I suppose anything is possible. It seems like the main questions is around having a way to track that the seller has actually generated the credits claimed and that they haven't already sold those credits to someone else, and a ways of collecting, cumulatively calculating and conveying that information in real time to buyers and sellers of LCFS credits.*
- The timing of the credit accounting is still an issue, and at minimum, and annual truing up of the books will be needed. ***Response:*** *Another question which needs to be answered is who would ultimately be responsible for making up for lost greenhouse gas reductions for any credits that were double counted, or sold more than once.*
- I think option 2 is a false option, because I think all my customers are going to want any credits they buy to be verified in advanced, and that could put DEQ in a situation where they are unable to manage the load of verification. I would prefer to see the program budget reflect the knowledge that there is a real demand for verification of credits.
- As a potential regulated party under the Oregon LCFS program, we wouldn't buy any credits unless they were verified, preferably with DEQ, with no clauses that would allow for an adjustment of credit value as a result of discovered errors in reporting. (Public Comment)
- In terms of the verification of credits, due to the uncertainty in the volumes of low carbon fuels that will be produced, and the costs involved with staffing new programs at the state level, the approach of running the program with some sort of third party assistance in facilitating the credit market with DEQ oversight as appropriate seems like a good start.
- I wonder if there should be some consideration existing credit markets that are run profitably by third parties, and a similar market could be created for LCFS credits that would operate under the guidance of DEQ so credits are verified without requiring DEQ staff time and resources.
- Options 1 and 2 don't seem very viable to me. It also seems like this is going to have to be self-supporting system because the legislature probably won't provide funding for such a program, so whether it's a third party or contractor, they are going to have to get the money from an administrative fee on the credits themselves. I don't think it can be on a % basis b/c if these things are going to go up and down, DEQs costs are going to be fixed each year, so they are going to have to recoup the exact costs of the program each year, so that is administrative aspect that needs to be looked at. I do not think that non-verifiable credits are a viable option.
- Do we need to verify that a particular fuel is that fuel, or can we have an approach that doesn't verify prior verification for every sale?
- I sense there are three different types of verification that are getting mottled. 1- that there is a compliance obligation to be met and the compliance calculation was don't correctly, 1- that the transaction is being made on good credit (number of credits sold actually at stated value exist) , and 3- the verification of the credits themselves. It's unclear to me if there is another way to get a credit other than through DEQ, in which case, why would I want to verify the validity of a credit if I can't get it on the black market? I'm struggling with the third aspect of verification, and if someone can correct me if worrying about whether a credit can be generated by any other means than through DEQ is a valid concern. I'm more concerned about the first two aspects I've described. Is that an accurate portrayal of the considerations to be made with regard to verification of credits? ***Response:*** *The first two, definitely. With regard to the third aspect you've described, credits would be generated when a regulated party sold a low carbon fuel. Credits*

wouldn't come from DEQ, and it would be possible for credits to be sold without DEQ being informed, so the question is – do sellers of credits need to go through DEQ to check invoices and verify the amount of fuel claimed as sold was accurate.

- Having a web interface that is run by DEQ as a forum where buyers and sellers can transact could minimize costs to DEQ. Requiring sellers to register with DEQ before selling credits into the LCFS market would provide transparency, but the aspect of verification may still need to be addressed.
- Can low carbon fuel providers outside of Oregon be a regulated party under the Oregon LCFS? ***Response:*** *Whoever imports the fuel into Oregon would be the regulated party under the LCFS.*
- This discussion is about how much certainty is needed about the volumes and carbon intensities of regulated fuels being bought and sold to determine whether the standard is being met.
- Blended biofuels sold to retail sellers contain fuels with two different pathways, and would have to verify the carbon intensities of both fuels, And when fuels are blended twice, where is what would be the equivalent to the incidence of taxation, and how will the values of the credits be verified? ***Response:*** *The buyer takes possession of a fuel and blends it, they will know the carbon intensity and volumes of fuels being blended to be able to calculate the carbon intensity of the final product and compare that to the standard. That is the relatively straight forward scenario. Another scenario that poses more of a challenge is where credits are purchased instead of actual product. Regulated parties will submit annual compliance reports to DEQ that can be used to verify that the regulated party does not sell more credits than they have*.
- The buyers of credits are going to want to know that the credits are good at the time of purchase, so an end of year audit won't work as a means of credit verification.
- Who is considered the regulated party? ***Response:*** *If it's manufactured in Oregon, the producer would be the regulated party, if it is imported, the regulated party would be the entity that imported the fuel.*
- If it is discovered that credits which were sold were not of sufficient value at the time of purchase for which they were represented to be worth, who is ultimately responsible for the compliance obligation?
- As a potential credit producer, it is my expectation that quarterly, we will verify that we aren't double counting production volumes.
- Credits could be sold separately from the fuel which generates the credits.
- We would not sell forecasted credits- we would only sell credits which have been verified. ***Response:*** *In a situation where a seller overvalues credits and sold them, the deficit is sitting with the buyer, but they would not be obligated to make up for that deficit if it could be demonstrated that the buyer practiced due diligence to verify the validity of the value of credits purchased. At that point, the obligation to make up for the deficit would rest with the seller.*
- Typically there are contractual remedies built into agreements that would address liability issues being discussed. ***Response:*** *Reviews of credits sold could happen quarterly to help catch them sooner.*
- We are in favor of transparency, and think it would help the market run better. We would like to see how many credits are on the market, the number of needed credits, and prevents periodic confusion as in other programs. ***Response:*** *It would also help DEQ because it gives us a sense of capacity and program tracking.*
- The challenge if regulating is that the mix in a tank is always changing due to the blending of fuels. ***Response:*** *That would be the case if you had to verify each credit transaction. But if the total volumes of fuels sold are aggregated on a yearly basis, that information can be accurately tracked.*

- But the issue is the need for accuracy for buyers of credits to know if they are getting full value of the credits they buy. ***Response:*** *I think if we set the rules up in the way we are discussing, buyers could rely on a registered option regulated party information, and if a seller oversold they are responsible for any deficits generated as a result.*
- If a purchaser of credits wants to know the value of the credits, they will need the volume and carbon intensity data of the fuels purchased in order to know what the credits are worth. ***Response:*** *Each credit will be one metric ton, so there is no difference between credits across fuel types. A regulated party will report to DEQ how many credits they generated based on the volumes and carbon intensities of the fuel the bought or sold. If a regulated party thinks they generated 100 credits but actually only generated 99 because their blend changed, it doesn't matter because at the end of the year DEQ will subtract the 100 credits and if they don't have enough credits left, they are going to have to make up the difference. All of the credits they sold would still be valued at the value for which they were sold. By registering with DEQ as a regulated or opt-in party, that regulated party takes on the obligation of selling an accurate credit.*
- All regulated parties will have to report regularly, and that should verify credit transactions. ***Response:*** *How much due diligence does the buyer need to do before buying credits? Might want to have information posted so potential buyers could know what the production capacity and pathways are to help them calculate and verify the value of credits being sold.*
- How elaborate does the audit need to be?
- We sell a variety of blends wholesale and retail, and the IRS and the State of Oregon show up randomly to audit us;, and my expectations here is similar in that at any point, I could be asked to prove the information submitted about volumes and carbon intensities of fuels being sold or generating credits for sale.
- There are three steps in the process that have to occur – a credit has to be generated, verified and sold. Before a credit can be sold, it has to be verified, and verification cannot happen before the claim of generation. (Public Comment) ***Response:*** *A program could be set up that way, but it would be very labor intensive to verify every credit before it is sold. We are trying to come up with a system where that is not necessary.*
- You might look at the program the green power program used by utilities to meet the Renewable Power Standard requirement. That program was all done on a voluntary basis, the generation was contracted out and PGE did the verification itself. That model could be useful for finding a suitable approach here. PGE was subject to audit and there was federal guidance on improper marketing. (Public Comment)
- Having false credits on the market would negatively impact the credit market, and so verification of credits prior to sale and transparency to do so are very important.
- Fuels can be tracked really well, so there isn't too much concern over where a batch of fuel came from or what the carbon intensity of blend is.
- If sellers of credits were required to post transaction information quarterly, this information could be used to get a closer to real time sense of the number of credits available on the market at any given time. I am a little concern about putting 100% liability on the seller and no liability on the buyer. ***Response:*** *That is why there would be some sort of minimum requirement of a buyer to exercise due diligence in trying to make sure that the credits they buy are bought from a registered opt-in or regulated party.*
- The federal EPA RIN system has worked because of the robustness of the verification aspect of the program. (Public Comment)

- Administrative request to consider, in addition to the narrative describing this process, can we also have a flow chart with inputs and outputs and time phases for the process, when a credit is generated, etc. diagramming how the process would work. ***Response***: *We can provide a flowchart in the final report*
- With regard to the options for levels of transparency, Level 3 - Quarterly reports used for compliance purposes (meet or within a percentage of standard) - this option causes some concern. Meeting the LCFS on a quarterly basis may prove challenging for some fuel types due to seasonal fluctuations in fuel quality. ***Response:*** *The benefit of a quarterly reporting schedule is that it would create demand for credits. The challenge it may present is that it creates more opportunities for violations and more administrative burden to review quarterly reports.* [No voiced support for this option/level.]

October 14, 2010 Advisory Committee Meeting

- We need to make sure that the carbon benefit is counted only in one regulatory platform/market. I'm guessing that the LCFS will be more lucrative, until the Brazillion ethanol importers start generating huge sums of credits - which will drive down the price. This presents another problem of devaluing the locally produced low CI fuel.

10. Fuel Supply Deferrals

August 5, 2010 Advisory Committee Meeting

- Compliance adjustment options is to give DEQ flexibility in being able to address a variety of fuel supply shortage scenarios and to be able to implement the appropriate type of deferral, based on a specific situation. If a disruption were so major, the compliance curve would need to be recalculated and the horizon year may need to be moved out.
- How does the issuing of deferrals affect the market place and the signals of creating low carbon fuels? The more forgiving you are, you are diminishing the market incentives, the less forgiving you are you are creating a premium which is going to create market incentives for more market supply. ***Response:*** *We are aware that this is an issue and we will try to balance these factors in moving forward with a proposal.*
- Are you suggesting normalizing or using a metric? ***Response:*** *Since it's a monitoring threshold, you'd want it to be simple and able to be spot it easily because all it does is trigger an investigation, and we want to avoid triggering an investigation every time a small disruption occurs.*
- With regard to monitoring, the only entity capable of knowing what's going on is DEQ, aside from an alert from a producer. With reporting mechanisms that will be in place, DEQ will have an ongoing data collection system, so (determining) when there is a red flag is a management decision, not an advisory committee decision. ***Response:*** *Agree.*
- If a regulated party opts not to comply, what is the enforcement and is the enforcement less onerous than complying? ***Response:*** *Different violations comes with different penalties, but a key element of penalties is that they would cover any kind of economic benefit gained in addition to the penalty.*
- A 25% is huge if you're talking about total CI weighted fuel. Even 5% is huge because you have to add in the amount you have to do better the next year.
- What would be a reasonable number? ***Response (Committee member)****: I don't know, this is a first flush. Short- and long-term deferrals are based on volume, whereas forecasted deferrals are based on the carbon intensity.*

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- Determining the significance threshold for when a supply disruption should trigger a deferral depends on how far out we're looking. The purpose of program is to get more low carbon fuel on the market. So if we were to base our decisions on the amount of low carbon fuel that is currently available on the market, we won't be able to meet the standard. But we are assuming that there will be growth, and this rule will generate additional demand, so when looking out 10 years, we need to use a more appropriate threshold. The threshold for determining if a deferral is warranted really depends on how far into the future the program compliance schedule is being assessed in tandem with the magnitude and duration of a low carbon fuel supply disruption.
- With regard to wanting to build a (low carbon fuel) market, one way to address forecasted deficits is to penalize the low carbon fuel providers for not meeting the standard, because that incentivizes them to get those plants up and running in a timely fashion.
- The timing question never was addressed: what is the timing of this process? If a supply disruption happens, it happens quickly. This is in direct conflict with the CCSN component- so it isn't making a lot of sense right now.
- But (the disruption) is only going to be at that plant for those particular regulated parties that have a contract with that plant, so its' not going to fit into the question of the scenario that has been presented so far today, or that is written up in this document. ***Response:*** *It's a good point that can be argued either way with regard to whether a disruption affects every supplier or just those under long-term contract.*
- Because enforcement costs more than compliance, they (regulated parties) aren't going to wait for DEQ to conduct an analysis- they are going to have to be out there complying.
- In the normal language for fuel supply contracts, to cover a situation where that supplier went down, what would the fuel purchaser do as a "plan B"? ***Response:*** *All companies have a robust planning department, and want to comply with every regulation in place, and that's why an expensive, complicated program like this doesn't make sense. Each company will have its own supply agreements, but it's not going to be on a universal, industry basis.*
- The difference is what's in the control of the company. For a permitted facility, their control device is under their control. Under the LCFS program, a regulated party doesn't have control of a fuel producer elsewhere.
- Will DEQ issue a violation for being out of compliance before the department knows if the scenario comes true or not. ***Response:*** *For a short-term disruption, when a plant goes down say for example, for two months, the goal would be to have the deferral in place before the compliance reporting which happens as soon as possible in the following year (perhaps sooner). If it's a longer term deferral and we're projecting out into the future, and wouldn't be able to achieve the curve in the year after, that's less of a problem. So if a disruption happens within a short time frame, DEQ would investigate the nature of a disruption and potentially grant a deferral.*
- It is important to leave room for what happens in the best case scenario – a breakthrough in technology – we should build flexibility in to the system so if there is a deferral granted for a one-year disruption, and the new technology emerges, it could make up for the difference and the deferral may be revoked.
- Does it (the granting of a deferral) have to be a public process? Can it be an administrative process? ***Response:*** *It depends on how the rule is written. The Department needs to seek advice from DOJ on this topic.*
- Please consider meeting with a small group that represents the interests involved that can explain in greater detail to DEQ what is going on, because this is all going to be market disruption in a variety of ways, and to understand what is going on, DEQ needs to hear from those that are in that market.

- I hope that the fuel cost is connected to this. ***Response:*** *That will be addressed via the Consumer Cost Safety Net.*
- The system being proposed won't work in practice because (a disruption) is going to happen too quickly for the first component and the price impacts and the alternative backfilling is going to potentially affect price out there. So to wait until you see something happening and then try to analyze it and implement something a few months down the road isn't going to happen. For the forecasted deferral scenario, you're still going to have questions on compliance and meeting obligations under the rule.
- Equal to conversation about making sure prices stay low, is making sure the signals are right for the alternative fuels producers. Some of the deferrals (short-term) may just be on a portion of the market, and the entire market wouldn't go away, so forgiveness would only be on the portion that was affected, and not on the fuels that were not affected, correct? ***Response:*** *Right.*
- A ten percent reduction in ten years is a significant change and equates to a lot of low carbon fuel, and where we run the economic analysis, we'll see that we are going to be asking the industry to really reach to get a 10% reduction, and we think its achievable but not easy, and we need to have a process in place to track our progress, and that's what this discussion is about.
- If we step back a little bit and realize that today there is a 90% monopoly on fuel imported into this state, and the price of that (imported fuel) is affected by world events, from spills, from wars- things that we live with all the time. We've seen the price volatility occurring and what we're looking at in the infancy of, is activating a local supply that is additive to what we're dealing with on a monopoly basis…feedstocks that are not impacted by world affairs and sensitivities. Granted it is still early and hard to see what will be out there in the future, but because local or regional volumes of transportation fuels are less dependent upon the monopoly-imported fuels, you are creating a dynamic , long-term solution, in which volatility should be dramatically reduced. ***Response:*** *That was one of the conclusions that California came to, (which is) that diversity of supply is part of the reason they projected that the LCFS program would reduce fuel costs over time.*
- I would like to see us stick to the end point. I would use rulemaking to change the end point if it needs be to (so as not to discourage low carbon fuel production), but would prefer not to alter the end point for short-term deficits.
- The forecast scenario deferrals seem like something worth exploring because that gives you a sense of where you are on the (compliance) curve, and how you are tracking along that curve.
- The short-term deferral scenarios are unclear because DEQ will not be as fast as the market, and the market will get around DEQ. It's more of a forgive and understand that over a year or two, you want to shoot towards a recovery, but it's really the forecast approaches that I'm interested in looking at keeping an eye on preserving or re-calibrating that curve.
- The overall purpose of the LCFS is reducing carbon emissions because they matter climatically and to Oregonian's well being. We need to track the cumulative emissions and if there are deferrals and forgiveness of deferrals, we need to take that into consideration because greenhouse gases have a long residence time in the atmosphere, and any lost time makes any future reductions that much harder and more important. There needs to be flexibility in the system to make sure that compliance is achievable throughout out the program and there is success, but we need to think carefully about how we shift the curve.
- To me, success of the program means getting to the year 2022 and being able to achieve reductions on a consistent basis from there on forward, being able to carry the program into the future and maybe think about phase two of this program. We don't want to do anything in the short term that would jeopardize

that. From my perspective, the most important thing is not to make up reductions lost in any given year, but getting back on the compliance curve the following year and move fuel technologies forward.

- The idea of banking credits is interesting so that some of the early actors can get the market moving, because in the early years it will be easier to meet the standard and if there are reductions happening that may build in a bit of a buffer moving forward.

Summary of written comments from advisory committee member or alternate December 1, 2010

- The significance threshold of forecasted supply for program deferral is far too low at 0.1 percent. The forecasts are usually predicted within a 5 percent confidence interval, so the threshold should be outside that range. In addition, if there is a deferral, the lost reductions of global warming pollution need to be factored into the future schedule of reductions.
- Clean Energy opposes DEQ's decision to allow the consideration and potential approval of temporary fuel supply deferrals as such provisions only create more uncertainty for low carbon fuel providers who are investing precious capital to produce low carbon fuels. While well intentioned, such policy actions tend to favor the regulated party and add risk to the very parties who are helping the state move the market in the right direction. As you know, the status quo already presents significant obstacles to low carbon fuel penetration as refiners have a virtual monopoly on fuels commonly used in light-, medium- and heavy-duty transportation in the US today. That is why Clean Energy doesn't understand why the DEQ would want to add further uncertainty into the marketplace.

11. Consumer Cost Safety Net

December 3, 2009 Advisory Committee Meeting

- The timeframe for an Environmental Quality Commission finding on whether exemptions and deferrals are necessary is too long. Could the Environmental Quality Commission could set up criteria in administrative rule, and then delegate the finding to staff? ***Response:*** *The commission can delegate some things to the DEQ, but when the statute specifies an Environmental Quality Commission finding (as HB 2186 does on this issue), it is unlikely that finding would be delegated to staff. But we could set up criteria so the process could be streamlined. There are other deferrals and exemptions to deal with adequate fuel supply that would be more immediate. The 12 month average is not just a price spike – it is a problem that has been building for months – it's a building problem, and would need analysis.*
- For a temporary spike in prices, it would be unlikely that getting rid of the LCFS in the short-term would have a substantial effect on price because you would not have changed the fuel stock over.
- Washington gasoline prices tend to be a few cents higher than Oregon's.
- Has DEQ done econometric analysis to see what inputs have driven up the price of gasoline? Wouldn't we do that to see what caused the Oregon price increases? ***Response:*** *No – the thought was that we would investigate the causes of an elevated Oregon price of gasoline once the 12 month rolling weighted average price in Oregon is more than five percent (proposed) above the statutory PADD-5(WA, OR, NV, AZ) price.*
- Right now Oregon's 12 month rolling weighted average price of gasoline is at 3.2 percent above the statutory PADD-5 average, so it wouldn't take much of a bump to put Oregon over the proposed 5 percent threshold. ***Response:*** *If the price went over 5 percent, exemptions and deferrals wouldn't automatically go into effect – there would need to be an investigation as to why the 12 month rolling*

weighted average in Oregon is 5 percent more than the statutory PADD-5. If it was from other factors, nothing would need to be done, but if it was due to the LCFS, then we would need to implement the exemptions or deferrals.

- Is there any way to back out the effect of Oregon not allowing self service? ***Response:*** *Even with the differences in self-serve between OR and WA, WA's price is still higher. The 12 month rolling weighted averages included in the discussion paper show the normal variation in the system without a LCFS, and with self-serve in WA but not OR.*
- The public needs to be aware of the cost of this policy and the commenter wants to ensure that the public knows the real cost of this policy. The commenter felt that this safety net is a fancy way of masking the real cost of the policy. The commenter suggests that the trigger for an investigation into whether exemptions or deferrals are necessary should be when the 12 month rolling weighted average price of gasoline or diesel in Oregon is ten percent, not five percent higher than the price in the statutory PADD-5. The public would then have to absorb more of the cost of the policy before something was done.
- For diesel, the 12-month rolling weighted averages need to be calculated without state tax because Oregon does not have a tax for on-road diesel, and the other states do. CA also has a sales tax.
- Is the task to model the factors causing an elevated Oregon 12-month rolling weighted average price of gasoline or diesel to understand how to identify when these happen? If you don't do that, then you won't know beforehand if it will be causal. The statute seems to ask for an econometric causation. ***Response:*** *The proposed approach is to investigate the cause of a price increase once the 12-month rolling weighted average price of gasoline has gone above five percent.*
- Some factors listed in the discussion paper would rule out that the LCFS was involved. They would be one-time occurrences that effect fuel supply or elevated crude prices with a resulting spike, and you could see clearly that they were the cause. Econometric analysis would be needed for more long-term trend analysis and to know which variable was trending upwards the most. Econometric analysis would not be needed in all cases.

- If a spike happens, you don't have a concept what caused it if you don't have a pre-determined theory of causation. Bounds on the criteria would be helpful. ***Response:*** *DEQ cannot predict all possible events that could cause a price spike. However, at points in the program where the required reduction has stepped up a notch, it may be more likely that any observed price increase is due to a shortage of low carbon fuels. In situations where the standard has not changed and there are no interruptions to the low carbon fuel supply, whether relative price increases are due to the LCFS may not be obvious and an econometric analysis may be necessary.*
- As shown on the graph, there is not a tremendous amount of variation between Oregon prices and the PADD5. This would mean Oregon's price is different than the 20-30 year history. You don't need to go through a huge econometric analysis to know that the LCFS is at fault. ***Response:*** *The Oregon price has gone above 5% compared to the other states without an LCFS. If Oregon's fuel was more expensive, the state would want to do what it could to decrease that difference. But if the price difference wasn't caused by the rule, we'd want to know what the cause was –if the LCFS was not the cause of the price increase, then deferring/exempting the LCFS could make the price situation worse. We would want to do an investigation to determine if the LCFS was causing a price difference and instigate exemptions and deferrals to address this. Also, there have been several times where Oregon's 12-month rolling weighted average price went over the same in the statutory PADD-5. Oregon's 12 month rolling weighted average price of gasoline has been over 5 percent of the statutory PADD-5's eight months since 1983 (3 percent of the time). For diesel, we only have the actual PADD-5 price information, and diesel has not gone 5 percent over the actual PADD-5 since 1983, although it has been close several times.*

- What happens if the Oregon 12-month rolling average stays over 5 percent and it is determined the cause is not the LCFS? What triggers the next investigation? There needs to be some flexibility in the rule to address this. If Oregon's fuel is considerably more expensive than our neighboring state, the legislature will want to look at that. ***Response:*** *DEQ needs to address this situation in the rule. For example, we could say that if the difference stays above 5 percent and the conditions haven't changed, we don't need to do another review.*
- Exempting a certain company or companies is fraught with problems, while exempting a certain fuel would be valid.
- There is concern if this is the only mechanism for dealing with price. ***Response:*** *The other deferral provisions address fuel supply, but they only indirectly address price. If you have an emergency supply disruption, that would translate into a price problem.*
- New companies producing biofuels could be negatively impacted by exemptions and deferrals. Also, there could be gaming with fuel prices that would cause an increase, resulting in the antithesis of what the rule is trying to accomplish. ***Response:*** *We'd need to be careful with using exemptions and deferrals. The exemptions and deferrals would not eliminate the entire LCFS requirement – you would roll back the standard to the previous year or delay the implementation of the next increase.*
- One unintended consequence of the proposed 5 percent non-competitive threshold is that such a low threshold for price variability doesn't encourage substitution. A higher range of allowed price impact would encourage substitution at a higher rate, potentially resulting in stabilization at a lower price later on. A 10 percent difference might be more appropriate for a trigger than 5 percent.
- We need to consider the consumer. Five percent is 15 cents per gallon, which means that truckers will buy fuel somewhere else other than Oregon, affecting Oregon fuel providers. This policy will affect a lot of different people. It's critical that we get this right or we will hurt someone. ***Response:*** *the most likely reason that the LCFS could cause the 12-month rolling average price to increase above the statutory PADD-5 price is the standard has stepped to the next reduction level, and there was not adequate low carbon fuel supply for that, or in anticipation of that next step in the LCFS reduction, there was hoarding of low carbon fuels. These are situations DEQ could anticipate before actually seeing a price change. The 12-month rolling average is a safety net element that was put into place as a backstop. There are other provisions that look at supply specifically. If we are three months out from a reduction in the LCFS, and we see the supply isn't there, the Environmental Quality Commission can implement a deferral. That is a more direct way to deal with supply issues. The 12 month rolling average safety net is for when something has gone wrong with the other deferrals.*
- Another variable is that because CA and possibly WA also will have LCFS programs, the preferred market for a low carbon fuel produced in Oregon might be elsewhere. Timing is important – DEQ should consider mirroring WA's timeline (in HB 2186). If we are the first, then we could have problems.
- There has to be a third party that could deal with this implementation issue of exemptions and deferrals for fuel price. DEQ should find a third party to use, as opposed to creating some sort of system. ***Response:*** *We can certainly consider this, but keep in mind that a 12-month rolling average price is not an emergency scenario – this is the backstop where something went wrong, and we're seeing it in the price. Our goal is to avoid this ever happening by setting a phase-in schedule which can be met with reasonable compliance scenarios, and having a process by which we're looking ahead, and we're sure regulated parties will be contacting us if they won't be able to meet the low carbon fuel demand in the next step down. Then we can change the compliance date beforehand to avoid price and fuel supply issues.*

- The advisory committee discussed what to do when there is a gap when Energy Information Administration data. Energy Information Administration price data comes out weekly – but there is a 3-4 month lag in volume data. Volume data is necessary to calculate the 12-month weighted rolling average. It was suggested that the most recent volume month could be used, but because there is seasonal variation in gasoline and diesel use, the previous year's data might be better. The best option might be to take the most recent 12 months data that you have as a first cut.

August 5, 2010 Advisory Committee Meeting

- What about (the price of) electricity, CNG, hydrogen? ***Response:*** *The statute refers specifically to gas and diesel. The theory being that since gas and diesel is where the reduction is needed, and if there are cost increases in other fuels which are generating credits or used to reduce the carbon intensity of fuel, they would show up in the price of gas and diesel. We are tracking gas and diesel because they are the compliance points for the curve, and any increases in the cost of low carbon fuels would show up there.*
- If there is a spike in fuel prices in Oregon related to a particular low carbon fuel needed, it's going to take us over a year to get relief from that. What I hear DEQ saying is that whatever happens and our economic study beats your economic study, then regulated parties would have to wait a year to a year and a half for relief. ***Response:*** *Only for the short-term deferrals.*
    - That's on supply, what if supply is there but price triggers (another monopoly develops). Is there a mechanism that should be put in place to enable a more immediate reaction to fuel price spikes? ***Response:*** *Part of it is the 12-month weighted average, so it's a balancing act.* **Response to Response:** *We have price gouging legislation in the state that's based on an incident, and if something comes up than the Governor can respond immediately. Why don't you have something like that available for the industry if there is some kind of a spike so we don't have to wait.*
- If it's a rolling average, we don't have to wait until the end of the year. ***Response:*** *If we had one really bad month because someone cornered the market on low carbon fuels for that month which caused a price spike, the previous months would dilute that.*
- A mechanism is needed to act on a shorter time frame to address price spikes in the marketplace.
- As long as it isn't triggered by the natural variation in the market.
- It would trigger an investigation, not necessarily a deferral. ***Response:*** *DEQ could have a trigger threshold to determine when an investigation is warranted and whether a deferral would alleviate the disruption problem, but the agency could also trigger an investigation of its own fruition before the threshold was triggered, based on the circumstances.*
- Going back to the question on non-blended fuels, in a situation where electricity prices go up differential to other places and credits from that electricity are generated and get passed on to comply, are those going to be ignored? Other fuels besides gas and diesel need to be looked at in this regard. ***Response:*** *Electricity providers are regulated in such a manner that would prevent that scenario from happening.*
    - The price of the credits is not regulated. The municipalities, PUDs and CODs aren't regulated. **Response:** *In ODOE's optimized analysis, even if five percent of the cars by 2020 were electric, it would only be 0.6% of demand for electricity in Oregon.*
    - I'm not talking about the price of electricity, I'm talking about the price of the credits. ***Response:*** *That would be the market price of gas or diesel, and if the price of that credit got high enough that credits would be needed, that would be reflected in the price of gasoline, which would be caught by the consumer cost safety net, which is why it all comes through the price of gasoline*

and diesel- if we aren't seeing that go above the consumer price safety net, then I don't think we need to worry about the other fuels.

- Are we really after GHG reduction, or are we telling out of state producers what they have to produce in order to be able to sell it in Oregon? By doing this, aren't we saying to people that if you want to sell fuel in Oregon, you need to comply with Oregon standards and make fuel that complies with what we require in Oregon? ***Response:*** *The idea of having Oregon establish GHG reduction targets (which are aspirational, not regulatory) is to achieve our share of the reductions needed to stabilize the global atmosphere, and would require every other state and every other nation to achieve those levels of reduction also in order to stabilize the atmosphere. The intent is to team up with California, Arizona, Washington and the other WCI states and a number of Canadian provinces, everyone doing their share, ultimately helping the federal government and other countries to decide to do their share as well. This rule by itself isn't going to fix global climate change, but it is a step in achieving the overall reductions that Oregon needs. In SB1059 the Transportation Commission is charged with establishing a greenhouse gas reduction strategy for transportation, and will be looking at this rule in context of the broader program to reduce GHG emissions in transportation, so it's a piece in a bigger effort.*
  - But still, we are basically telling out of state producers that if they want to sell in Oregon, they have to meet certain standards ***Response:*** *We do that with a lot of things*.

Summary of written comments from advisory committee member or alternate December 1, 2010

- While Clean Energy understands DEQ's intent to show consumer sensitivity and Clean Energy believes giving consumers more transportation fuel options than the status quo adds competition and therefore lowers prices, we feel adding a consumer cost safety net adds another level of uncertainty. Although Clean Energy would like to believe low carbon fuels are as cost competitive as natural gas to petroleum, unfortunately, this is not always the case. In fact, this is why a LCFS policy is needed: to create the right policy incentives needed to develop the marketplace so that one day consumers could benefit from an array of competing clean fuels rather than the status quo which is dominated by gasoline and diesel. We strongly encourage DEQ to reconsider the need for a consumer cost safety net in the future if it opts not to remove it at this time.

12. Implementation Issues

A. Use of Biofuels

Summary of written comments from advisory committee member or alternate December 4, 2009 regarding the proposed biofuels use

- Set up a transition fund (like the diesel retrofits) to help the legacy vehicles change fuel filters and fuel lines to take blended fuel, if blended fuel is actually required. Keeping in mind that regular fuel providers could be blending or buying credits.

April 15, 2010 Advisory Committee Meeting

- I would assume that all these biofuels would have specifications that need to be met as opposed to mandates for blending. Again, this is a market performance-based system. If something is not meeting the specification, someone else is going to jump in with a better fuel that is meeting the specification. We need to make sure the specifications are there that meet off-road or customer requirement conditions.

- What do you do when you are in the middle of a job and the equipment is not working? For the LCFS to work, it has to work in individual pieces of equipment. And in much of Eastern Oregon, the equipment operates differently.
- In Eastern Oregon, I have heard a lot about gelling problems they had with 2% biodiesel that we had last winter. The fuel was separating and the biofuel was going to the bottom of the tank.
- Minnesota is not having the same problems and they have been using biodiesel for about five years. The problems Eastern Oregon is having are rampant to the point that in February the Legislature passed a bill that suspends the 2% mandate next winter so that we can look at this problem and see what it is. So it is very real and I'm not sure the existing literature is going to shed a whole lot of light on this. It is a huge problem.
- Minnesota had the first biodiesel mandate and it gets cold in Minnesota.
- The low carbon fuel standard is different from any type of particular blending mandate. The low carbon fuel standard can be met with no biodiesel whatsoever.
- Oregon Department of Agriculture did a great job of studying that issue. The problems have been blown up compared to what actually happened. We have lots of history in Oregon of much higher blends than 2% operating fine in cold weather snaps. Oregon Department of Agriculture did a really good job of testing fuel and seeing what was actually happening out there. One of the primary principles behind having a low carbon fuel standard and not a renewable fuel standard is that we are not saying that you have to burn 10% biodiesel whether you like it or not. At some point, the committee should be able to get to the point that we do not have to keep saying that repeatedly, and we can move past that. We are trying to create a scenario to achieve our carbon reduction goals while letting the market figure out how to make that happen and it can happen many different ways.
- The people (in Eastern Oregon having gelling problems) that you brought up earlier - were they using any anti-gel agents in their fuels? ***Response***: ***(Russell)*** *They were using additives and they were not blending #1 with #2. We have traditionally dealt with the gelling of diesel, which will gel in cold temperatures. We have gone to above ground storage tanks in Oregon to reduce the ground water contamination and the fuel is more susceptible to temperature variations. Businesses with below ground tanks had no problems. The trucking companies with above ground tanks had huge problems.*
- I want to encourage us to move on, off of this topic, because it has perennially come up and we have identified that in Minnesota they do not have this problem. It is clearly just a performance specification and storage standard issue, and I think it distracts us from the discussion of the giant list of fuels assessment we have on the agenda. It continues to come up so I believe it is a legitimate concern, but I do not believe this is the forum for us to be trying to find a solution to the ASTM specifications and additive specifications that are required. I would encourage someone to come forward with the specifications that are effective and working in Minnesota.
- I just want to emphasize that this is important and the full analysis that we need to make not be too narrow. The problem with the increase in biodiesel is an issue because it has to do with another rulemaking. We need to make sure that whatever analysis on this makes sure that we do not have many unintended consequences down the road.
- As we are planning something that is large and complicated and is based on assumptions, which affects how we assess if we will have future problems, there is a potential for real interruption of the ability to conduct business. I am suggesting in your compliance scenario that you have to consider those and allow

for that. Not just specific to biofuel, but to all of them. ***Response: (CARB)*** *the use of biofuels was an important and critical issue in California. For one thing, all biodiesel is not the same. The properties and the quality control for some production facilities is not what it is supposed to be. A current study addresses these issues and determines exactly what specifications we are going to be able to enforce to avoid any problems. This is an issue that we need to pay a lot of attention to, because we do not want to have a problem with vehicles or equipment. Avoiding problems could require additional standards for fuel. We are looking at engines and emissions performance. Different types of biofuels might create some increase in emissions.* ***Response: (DEQ)*** *To acknowledge the validity of both sides of this discussion, I think we are saying that this is an important issue. With regard to our standard, there are a couple of ways we are handling the potential biofuels issue. One is the back-loaded phase-in-schedule. In 2022, we will need to be at full compliance and might have larger volumes of biofuels. The intervening time is enough time to study the quality control and put better practices into place. The statue requires the fuel specs, but it also requires us to defer the requirements if necessary to prevent disruptions of fuel supplies. HB 2186 puts mechanisms in place so that we can defer to the requirements for an additional year or two. Currently, we are trying to design five compliance scenarios. We have to assume in at least some of those scenarios that the problems are worked out and we can have higher levels of biofuels. We are evaluating a range of possible futures.*

- Biodiesel blends are also an issue for warranties on other types of engines.
- ***Clarification (DEQ):*** *Provisions outside of Oregon's rule will limit blend percentages for biofuels.*

B. <u>Storage and Distribution of Low Carbon Fuels</u>

C. <u>Recordkeeping and Reporting</u>

February 24, 2010 Advisory Committee Meeting

- Oregon will need processes in place to protect confidential business information.
- A more transparent reporting system will lead to a better-functioning, more responsive market.
- Does ODOT's system have exemptions built-in already for farm vehicles? ***Response*** *(ODOT): Farm vehicles with plates are not exempt, but farm equipment is.*
- Trading of credits is a unique aspect of the LCFS and needs to be taken into account carefully.
- Adding LCFS reporting requirements to existing ACDP and Title V permits would not necessarily add any efficiencies, just as easy to report separately. Could be legal ramifications as well.
- Chair Reeve pointed out that HB 2186 directs DEQ to look at possible ways to coordinate reporting obligations with existing programs, but that it may not be practical.
- Keeping reporting simple will encourage opt-in parties to opt-in.
- Several committee members expressed their support for using an adapted version of California's web-based reporting tool.
- It would be beneficial for potential opt-in parties to be able to enter their information before opting in, in order to see whether and how much they could benefit by generating credits.
- Air quality permits seem an unlikely partner for LCFS reporting, GHG reporting seems more likely.
- Oregon will have to modify CARB's carbon intensity library if we use different calculation methods, or if we decide to pool gasoline and diesel for compliance.

- Could DEQ use the LCFS system as the basis for the GHG reporting system? ***Response:*** *Different reporters and emission quantification methods are involved, but there is some overlap. We will continue to consider whether it makes sense.*

D. Enforcement

- *No comments*

E. Standards, Specification, Testing Requirements to Ensure Quality of Fuels

- *No comments*

13. Review of Rule

May 20, 2010 Advisory Committee Meeting

- Is there a way that we can incorporate into rule a set of criteria by with which we periodically review the rule instead of conducting secondary rule making?
- Is rulemaking necessary for a new fuel or could someone submit a lifecycle analysis new pathway and DEQ could approve it administratively? ***Response:*** *It is likely that we could approve a carbon intensity number administratively. That carbon intensity number and that administrative approval could only apply to the person that applied. We would need to do rulemaking for another fuel producer to use that carbon intensity number.*
- Will the carbon intensity for gasoline and diesel change? ***Response:*** *If the refining efficiency changed significantly, a petroleum company could use the New Fuel Pathway process to update their carbon intensity.*
- The structure of having the companies come to us with the new carbon intensity will create a race to the lowest carbon intensity without ever reflecting an increase.
- Crude shuffling raises greenhouse gas emissions in some other jurisdiction and that is what DEQ is trying to avoid.
- It would be good to track of advances in fuel life cycle assessment before 2016. Science is advancing. Commenter is concerned with waiting until 2016 when this data may be available sooner.
- Identification of hurdles or barriers to increase the use and supplies of low carbon fuels may require visiting earlier than 2016. If feedstocks are waste-based, there are still some kinks to be ironed out between the Renewable Portfolio Standard (RPS), the Renewable Fuel Standard (RFS), low carbon fuel standards, and beneficial use rules. There is some confusion about when something gets to be called a waste, which gets you a zero carbon value as a feedstock. I think there is some upstream or downstream regulatory intercepts that need to be looked at. These are things that would end up requiring changes outside of the LCFS program, but that DEQ needs be aware of. ***Response:*** *This is discussing the review of our LCFS program and program rules. We could be looking at those issues, but this comprehensive review is for the LCFS program. So if your points would lead to possible changes in the program and the program rules then we should include it and then otherwise we should not include it.*

  Well, if it inadvertently stymies the LCFS program, it would need to be addressed before 2016.

- The National Science Foundation's study has been recently commissioned and is due out in 2012, and addresses fuel life cycles, including indirect land use change. This would influence the implementation of the LCFS and should be reviewed at that time.
- The harmonization should be reviewed on an as needed basis because changes could happen regionally or federally.

14. Flexible Implementation Approaches to Minimize Compliance Cost

- *No comments*

15. Effect of the Sunset

Summary of written comments from advisory committee member or alternate September 30, 2010

- The questions you raise in your memo regarding the potential impact of the 2015 sunset to the LCFS are the right questions. In addition, I would add the potential short term impact on needed capital investments to provide clean fuel supply in later years. For example, ZeaChem is building current capacity for 250,000 gallons per year (not much), but could easily expand production capacity to 50 million gallons (with cellulosic technology, maybe one-third of the total LCFS fuel needs). The sunset could serve as a disincentive for those capital upgrades to be made in the next couple years, which could have long-term implications to the program. Removing the sunset in 2011 or 2012 becomes potentially imperative.

October 7, 2010 Advisory Committee Meeting

- As we look at biofuels and taking additional cropland to grow feedstocks, are you going to get water, and are we going to take food away from people in the process. Farmers in eastern Oregon are concerned about the costs that will be borne to them. We need to be careful that we don't create one problem while attempting to alleviate another. I don't want to see family wage jobs reduced or elimination. I hope that there is communication with the legislature and the OUC to avoid creating unintended problems in the future. ***Response:*** *These issues will be addressed in the economic analysis in the October 14th meeting.*
- The state RFS and federal RFS are going to stimulate biofuels production and capacity, and Oregon is a small market, so the effect of the sunset seems small.
- There is a significant benefit for locally based companies in Oregon and the resulting effects benefits on labor, rural counties, and secondary business that benefit from the Oregon based biofuels producers.
- The sunset creates uncertainty in the market and does not incent innovation or investment in infrastructure. Instead of asking what effect of a sunset would be, the better question is; what is the benefit of a sunset?
- Proposal for a strong recommendation that the sunset would not be a positive incentive in the marketplace. It is proven that when looking at large capital investments that a sunset date isn't the actual sunset date. Most of the equipment, technology engineering and design have lead times of up to 18 months, and a sunset may in effect kill market investment in capital improvements for biofuels as much as 18 months in advance of the sunset. On the white paper, the start of the third paragraph reads

"Presumably"- my advice is that we not presume (delete "presumably") because the sunset will have a negative impact on long range capital planning for new developers.

- There are different views about the wisdom of this program, but the purpose of discussing it is to incorporate the various views on the effect of the sunset.
- Falling back on RFS and RFS2 is a good way to ensure that a sunset does occur, and RFS and RFS2 are not fuel-neutral policies. Instead of a sunset, a review of the program may be more appropriate in 2015. Investors will take a sunset into consideration when planning projects. I strongly encourage DEQ to make the case to the legislature to review rather than potentially derail the program. If you want to encourage investment, the uncertainty of a sunset needs to be removed.
- What would initiate a program sunset? What would cause it to happen? ***Response:*** *If the sunset is not lifted, the LCFS program will terminate effective January 1, 2015 and all compliance obligations under the LCFS would cease to exist. DEQ is not going to take this to the 2011 legislature, but someone else could.*
- The debate over the LFCS was close in the legislature, and there is a risk of going to the legislature and asking them to lift the sunset in the 2011 session before we are able to demonstrate how the program will work.
- I agree, but the more certainty I have as a potential low carbon fuel producer, the better.
- I think any uncertainty will affect biofuels more than electricity used for transportation. ***Response:*** *We want to be able to describe how the program will be affected from now until 2015 when the sunset remains effective. We won't have this program as a partial driver to reduce greenhouse gas emissions and the impact of having the program end on the goal for a 10% reduction in greenhouse gas without making any recommendations regarding the sunset to the 2011 legislature.*
- The biofuels industry had a federal tax credit that was not renewed at the end of last year and that has had the impact of reducing our national capacity to produce our particular type of fuel by 70 to 80% and has resulted in thousands of job losses. That is an example of what can happen when incentives are removed, and the sunset would essentially bring to an end the incentive to reduce greenhouse gas from transportation fuels via the LCFS program.
- The frame of the sunset will ultimately have an effect on the 2022 program goal of greenhouse gas emissions reductions. With regard to the impact of LCFS on agriculture, the feedstocks for fuels typically won't come from labor intensive lands, so the tradeoff isn't one of jobs or producers. On electric vehicles infrastructure, LCFS won't be the driver for infrastructure, but it could affect choices drivers make for the vehicle miles traveled in an electric vehicle.
- I would hope that we would produce wheat that is used for food and the wheat stover that is left over from harvesting the wheat would then be used to produce biofuels.
- To the extent that there are early creation of credits in the first couple of years in the LCFS program and the program sunsets, there wouldn't be any value to the credits upon sunset of the program – does anyone have any thoughts on that?
- It's clearly a taking and it clearly devalues the credits from the outset if they have a risk of evaporation sometime in the standard.
- If there is not LCFS, one might expect that it could dampen the ongoing development of electric vehicle infrastructure. DEQ recognizes that there are other efforts currently underway to build electric vehicle infrastructure, and the LCFS is ancillary to those efforts.
- Having this program in place helps as a driver to further electric vehicle development in Oregon.

- One of the big barriers for all low carbon fuels is getting the infrastructure in place, and one of the potential benefits of an LCFS is the incentive that is created for biofuels infrastructure. By creating the demand for credits potentially creates demand for infrastructure development.
- We may not invest in low carbon fuels in Oregon as we would like to without the incentives to make them pencil out.
- Right now there is overlap between the initial couple of years of the program and a decision about the sunset. We are envisioning 2012 as the first reporting year and 2013 the first compliance year, so somewhere in that year a decision about the sunset will need to be made. DEQ is investing resources to this program with the recognition that the sunset could go into effect in order to demonstrate to the legislature how the program will operate beyond the sunset date.

Summary of written comments from advisory committee member or alternate December 1, 2010

- The 2015 sunset should be eliminated. The sunset creates uncertainty for investment and potentially makes the program more costly. The majority of benefits to Oregon accrues in the later years of the program and will be missed if the sunset stays in place. The state's investment up to this point will be fairly meaningless without removing the sunset.
- DEQ correctly recognizes the negative impacts of the current sunset clause in 2015 to the development of low carbon fuels in Oregon. ZeaChem is currently constructing a 250,000 gallon per year demonstration scale biorefinery in Boardman, which will come online in 2011. Based upon the successful operations of the demonstration facility, ZeaChem will begin to develop commercial scale biorefineries and is considering Boardman as the site of its first commercial biorefinery. Businesses such as ZeaChem need long-term policy in place to support and incentivize new business opportunities, such as low carbon fuel production. Recommendation: Since the LCFS goal is to reduce carbon over a 10-year period by 10%, it does not make regulatory or business sense for the LCFS to sunset in 2015. By extending the sunset to 2022, Oregon will send a strong signal that low carbon fuel production is encouraged in the state. In addition, the timeline will be consistent with the federal Renewable Fuels Standard (RFS2), which sets volume production goals until 2022. ZeaChem supports DEQ's efforts to extend the sunset provision through legislation so that current and future low carbon fuels producers can be certain the state of Oregon is committed to this industry.

VII. Calculating Carbon Intensities for Oregon's Transportation Fuels

1. Direct

December 3, 2009 Advisory Committee Meeting

- DEQ may not want to include a hard number in the carbon intensity table for electricity, because the number is definitely going to decrease over time due to the Renewable Portfolio Standard. Instead, perhaps the rules could provide a process for the electricity carbon intensity value to be updated annually. DEQ will get information annually on electric utility emissions through the greenhouse gas reporting rule.

- Electricity carbon intensity could also go up – it fluctuates due to weather and other causes, and fuel providers should not be surprised by such factors beyond their control. A rolling three-year or five-year average may work best.
- Post-consumer biomass sources, such as consumer waste and plastic waste, are not on DEQ's list so far, and since they will not have indirect land use effects associated with them, they will have an advantage. This technology may be coming sooner than we realize. ***Response** (CARB): CARB has investigated waste oil as a feedstock so far, and plans to analyze other waste sources, all of which will not have indirect land use effects.*
- Is extraction process included in the life cycle analysis? Commenter's specific concern is ensuring that higher emissions from Alberta oil sands crudes are reflected in Oregon's carbon intensity analysis. Information on carbon intensities of Alberta oil sands was provided by Western States Petroleum Association for committee members. ***Response**: Yes, the extraction process is included in the life cycle analysis.*

January 27, 2010 Advisory Committee Meeting

- How recent is the information on oilsands crude, and can we get more recent data? ***Response:** DEQ is using 2009 data for the proportion of crude from Canadian oil sands.*
- Electricity source data as presented is misleading. Committee member can provide DEQ with more detailed information on the source mix for individual utilities, so that refinery electricity information will be more accurate. ***Response** (CARB): California looked at refineries as a sector, rather than individually, when calculating that portion of petroleum carbon intensities. If they are disaggregated for electricity sources, then they would need to be disaggregated for other aspects as well. California used averages for initial calculations, but may reconsider this decision in the future.*
- How are crudes tracked in Washington vs. California? ***Response** (WSPA): California's Energy Commission monitors crudes used in California and has extensive, as well as more up-to-date, data. Washington relies upon the federal Energy Information Administration data, with a delay in availability. WSPA has submitted studies on oilsands' carbon intensity, which DEQ has posted for committee members.*
- Lag in numbers is concerning. What data will determine compliance with the program targets? ***Response:** DEQ will need to track the numbers over time to see if the crude mix has changed significantly from what it was when the baseline was set, to ensure that carbon intensity increases in the base fuel don't outweigh the benefits from alternative fuels under the program. DEQ will be able to track this from compliance reports, which will be more up-to-date than Energy Information Administration reports.*
- Why doesn't DEQ require petroleum companies to report their crude sources and volumes as part of LCFS compliance? ***Response** (WSPA): That would present antitrust problems as well as confidentiality issues. Information currently reported is filtered and consolidated to account for these concerns.* ***Response:** DEQ will track information on oilsands and other factors that are most likely to make a significant impact on carbon intensity over time.*

Summary of written comments from advisory committee member or alternate April 21, 2010 regarding electricity issues.

- We do not see a simple way to calculate utility-specific values since each utility relies upon some amount of undifferentiated power purchases to supply a portion of its retail product. Also there is a question on whether a carbon value should be imputed to renewable electricity where the environmental attributes have been sold (and if the answer is "yes", what should the imputed carbon value be?).

- If the Department chooses to move forward with utility-specific values, PacifiCorp requests the rule also include a petition process, whereby an entity may petition to update a utility-specific value. We are concerned with locking in a utility-specific value based upon a one-time calculation. Doing so could disadvantage entities wishing to install charging equipment within PacifiCorp's service territory. We also anticipate the carbon intensity of our retail product to decline over time, which would likewise increase the value of transportation electrification (and thus LCFS credits produced) within our service territory over time.
- Finally, until our utility commission provides guidance, it is unlikely PacifiCorp would opt into the LCFS program. There appears to be a possibility for a utility to opt in either: 1) as a direct owner and user of electric vehicle charging equipment (and thus retaining title to the electricity sold for transportation use) or 2) acting as an approved aggregator on behalf of our retail customers (where the appropriate rights have been conveyed to the utility by the retail customer/charger owner). I only bring this up to make sure no one assumes a utility will necessarily opt into the LCFS program. Such a conversation needs to occur at the public utility commission and include stakeholders. Before opting in, PacifiCorp will need a commission decision articulating whether registering LCFS credits is an appropriate new task to be added to the regulated utility's job description.

May 20, 2010 Advisory Committee Meeting

- Electric utilities are still going to have increased load growth, even after accounting for conservation. Neither conservation nor renewables will completely offset future load growth. Natural gas will be the source of that new electricity. Oregon has emission performance standards, so utilities will not be investing in any long term resources that involve coal. Natural gas is a good balance for renewables because of the ability to come online and offline quickly.
- We could use the IRP (individual resource plans) to calculate carbon intensities. The smaller utilities will be a little bit more difficult.
- A better way to calculate the electricity carbon intensity would be by utility, or ideally by time of day by utility. That would be ideal, but that becomes administratively untenable and complex.
- We need to think about the ramifications of starting to look at different fuels differently. For example, since we put all of gasoline into a bin, we should put all of electricity in a bin.
- I think it is a logical jump to attribute the marginal resource demand to electric vehicles.
- We have an integrated resource blend. If I was building a new factory and I had to do greenhouse gas reporting, do I get to claim only the marginal electricity that I'm buying? Conversely, if I have an old pulp mill or lumber mill that has been around for 100 years can I claim just using hydro? It is not a first in/first out system and so we should do it by utility.
- The frequency of calculation is important, especially in the Northwest with hydro regimes changing year to year. The carbon intensity may increase for a utility from one year to another or decrease.
- Renewable Energy Credits might not be appropriate for the LCFS
- Commenter thinks the carbon intensity of green power could be used if it charges a vehicle.
- If Oregon utilities are held accountable for their production through the LCFS, that creates an incentive.

- Commenter thinks the statewide average is better.
- Some utilities have a lower carbon intensity than the statewide average, and might protest this. ***Response:*** *DEQ met with representatives from OMEU, OPUDA and Rural Electric Co-ops, and interested utilities several times to get a sense of this issue, and the feedback was that the statewide average is acceptable. There are really good arguments to be made on all sides here. There is not a real right or wrong answer, but we are trying to develop a program to reduce the carbon intensity of transportation fuel over the next ten years. Electricity use over the next ten years is going to be primarily for other purposes besides transportation. Transportation will never be more than a quarter of a percent of the electricity used in Oregon over the next ten years. Hopefully, it will grow over time. So whatever we do here to incentivize power plants is not going to be felt in their system. What is really driving them towards lower carbon sources is the renewable portfolio standard. Whether we provide utility-specific or marginal or average is not going to really affect them. They may not even opt in at all. To me, it makes more sense to think about using a statewide average and whether it is the marginal 59 or whether it is the average 52. It is one of the things that we can re-visit in 2016 and we can certainly re-visit it in 2022 when we are thinking about re-upping this program. There are other forces that are much much more significant driving utilities towards renewables and we should just keep our LCFS program as simple as we can. Also, given that people are going to buy an electric car and we don't know where they are going to charge or sell their car, who knows what kind of incentive we are really sending to consumers. Keeping it simple with one average number makes a lot of sense, however there are other views that are perfectly valid too.*
- Commenter agrees with using the marginal increase for electricity in concept. Another issue is the charging during the night versus the day. In terms of connecting the Renewable Portfolio Standard (RPS) and low carbon fuel standard, I think there is a close comparison to the Renewable Fuel Standard (RFS) and the low carbon fuel standard and the two should not be connected because they are achieving different results. Similarly, I think the RPS's and low carbon fuel standard are separate in the sense that one is trying to drive renewables within the electricity market and one is trying to address carbon intensity in fuels and those are two separate things.

- Okay, so what are the barriers to opt-in or what are the things we can tweak to encourage opt-in to make this an effective part of the rule? Would it affect your decision to opt-in if there was one average number or whether each utility had its own number?
- A utility could voluntarily beef up their portfolio and renewables, decrease their carbon intensity, and market that. If you assign just blanket average carbon intensity then there is no value to sell.
- If the carbon intensity is zero versus 59, they have a more credits to market. ***Response****: You are making a valid point. But under the federal regime of cap and trade, they are going to also have to pay for all of the carbon from the electricity that they are selling into this market. I don't think they are going to be making investments right now just to support electric vehicles.*
- If the utility opts-in we they get the credits, but getting those credits has been motivated by somebody else's choice to purchase an electric vehicle.
- There are new groups that want to just serve electric transportation markets as an electricity retailer. Do they get lumped in with all the existing utilities?
- Statistical research methods are highly accurate and hugely cheaper than metering electricity use of electric vehicles with a sub-meter. So I would encourage us to not do what California did with , unloading ridiculous costs onto the system.

- I think there are two different things that we are trying to do. One is how do we get people to opt-in? And then the other is, once they are opted-in how do we encourage them to get cleaner electricity. Once people have opted in then we can create a market between the utilities to create cleaner fuels. So a statewide average is fine for opting in, but once they have opted in, maybe we can revisit this and talk about how we encourage competition between the utilities to clean up the fuels.
- Cheap power or lower carbon power is an economic driver and it brings manufacturing to locations as a value. And as carbon is going to get regulated more and more, we are going to see manufacturers heading towards lower carbon power. So I don' think we want to average that out and take away that affect for this sector.
- Part of the reason for doing this is the competition, right? To be able to provide a service that somebody else can't provide. So I think in this limited case of a new entity coming in to provide electric vehicle that is connected to cleaner energy that makes sense to include them to have a pathway to get credit for it. Under the current electricity law in Oregon, we don't really have competition between utilities and they are definitely not going to compete for service area around low carbon fuel standards. There is no reason to try to create a competition between them.
- An exception in public utility regulatory code allows unregulated sale of electricity to vehicles.

  One scenario is that we could allow a fuel pathway for anyone that access those particular rules and anybody else is going to get the marginal new resource power and then you have it covered.
- DEQ would establish the carbon intensity for electricity at the new resource power level of 59 for all electricity in the state with the exception that if power is sold through this process described above was where there is a special statute or rule that they are accessing, they could apply for a new fuel pathway to go along with that.
- It is important for homeowners to have an easy opt-in process to get approval from the utility for credits. If the utility does not opt-in, the homeowner should automatically be allowed to opt-in.
- Commenter is unsure about including activities such as truck stop electrification in the LCFS, because HB 2186 had truck idling and low carbon fuel standards in different sections for a reason.
- Using the new resource power as the mix ignores the fact that we do have all of this existing resource that we are generating electricity with. Given the time of day, the actual electron that this car is using isn't necessarily the new resource power.
- If we choose the statewide average, we will set a precedent, and will not be able to go back to individual carbon intensities.
- The advisory committee group present found the following solution acceptable. DEQ will establish the carbon intensity for electricity at the statewide average for all electricity in the state with the exception that if power is sold through by an electricity supplier by virtue of the PUC rule that allows unregulated sale of electricity to vehicles, they could apply for a new fuel pathway to go along with that. Sub-pathways for specific utilities cannot be used.

  DEQ will use the statewide average electricity carbon intensity for electricity used in the production of fuels.

June 23, 2010 Advisory Committee Meeting

Putting vehicle CO2 emission for ethanol at zero is not intellectually honest. ***Response:*** *There needs to be a footnote explaining that there are emissions at the tailpipe, but they are neutralized by the CO2 consumption by the plants used as a fuel feedstock.*

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Summary of written comments from advisory committee member or alternate July 27, 2010

- First of all, I think electricity is our only hope of matching the scale of todays' need for transportation energy. UCO and Biomass and Waste to fuels will only get us part of the way there. Electricity and efficiency has to get us the rest of the way there. In the next few decades, I can see that the heavy freight world is unlikely to switch to electricity. At the margins like hoteling of trucks, and on-shore power for boats and maybe even switching engines for rail yards, but largely diesel will remain and will need to be done better. While everyone is excited about natural gas, I think the loss of coal will absorb that quickly into the electricity markets and may make it less attractive from a price standpoint. Which leaves us with Personal vehicles - for which I think we have too much of anyway, but also these have a reasonable hope of going electric.
- Essentially, I think that a statewide carbon intensity /Oregon grid mix assignment may make sense as a practical matter, but will reward the dirtier grids/utility portfolios and provide little incentives for the cleaner aggregators (EWEB) to trade credits inside of the transportation cap. I think that EWEB will de-facto subsidize the fossil energy intensive portfolios and discourage the business model wherein EWEB could market or hold credits that users inside of their system would generate.
- I also see that collecting the data on electric car charging would be relatively easy to account for for these reasons:
- Electric car buyers will start in two groups - captive fleets and residential enthusiasts.
- For a captive fleet I believe that they will notice the load and cost growth on their bills and will be able to plot that new demand. The utility will likely notice that as they will need to be involved in the installation of charging stations. Ditto for the residential user. If 4 or 5 residences in one feeder add home charging stations, likely the distribution infrastructure will need to be adjusted - again, hard to miss for the utility/aggregator.
- The argument that electric cars will soon be charging in multiple utility jurisdictions and therefore it will be impossible to tell what the individual is generating credit wise falls flat on its face for one reason. Money. How long will utilities, malls and workplaces pick up the personal fuel/electricity costs for free? I say not long. As soon as there is any significant consumption, the meters will show up on the charging stations. They already have for trucks - Shorepower. Free power is an anomaly of today that is there only to get people excited. It won't last.
- So, the aggregators will either be public metered charging stations, fleet fueling and storage yards or residences - none of which will slip by the notice of the power providers and those that pay for them.
- Now related to carbon intensities of the electricity providers - a state grid mix won't cut it, because there is an incentive to go lower than that by providing renewable power. If I owned a charging station chain, I would buy RECs or offsets at $1/tonne from landfill gas capture, bundle it with the electricity provided at the charging station and accumulate large amounts of credits to sell in the LCFS at a substantially higher price given the likely scarcity of credits inside of a fuels cap compared to an economy wide cap. This would be a fair way to play int he LCFS as I currently see it. What DEQ may want to consider is limiting the dedicated carbon credits to such a business model to voluntary RECS only. This would ensure that the power was actually linked to a renewable source and reward the further expansion of renewable power to help our country ramp up for the electrification of the transportation sector - which must happen if we assume that transportation activity continues as it is or grows. Offsets would help restore or make other parts of the grid more efficient, which may or may not provide additional capacity to power transportation. But what we really need is more renewable power generation infrastructure.

- Which leads me to the title of this email - we simply must ensure that aggregators/utilities do not use their RPS compliant power required under another regulatory construct to generate credits in the LCFS cap. This is the double counting that I fear. That's why if a utility is to aggregate that load from EV's they should be generating the credits through the purchase of **Voluntary** RECS or any portion of their portfolio that is not meeting their RPS thresholds. It would not be difficult for them to purchase these in blocks and track the accounting.
- This would lead to a CI of....<1? Or zero divided by 3 for the EV efficiency factor? I think that voluntary RECs powering EV's is closest to the ideal for personal vehicles. These credits should be worth the most.
- We wish to continue working with staff on the actual CI value given to our facility in Boardman because we feel the electricity component is not correct. Ie. Our electricity is 100% hydro, unlike statewide average which includes coal. It is important the companies have an avenue to fully develop alternative pathways and show the true ci values of the process.

2. Indirect Land Use Change and Other Indirect Effects

- Commenter is troubled at idea of including indirect effects for vehicle components. This goes beyond fuels, which is the committee's charge. ***Response***: *Example comes from California's analysis. CARB ultimately decided to include only indirect land use change effects.*
- Will land use for non-biofuels be considered? *Response: Yes.*
- Indirect impacts analysis should not focus only on alternative fuels, but should also consider indirect impacts of petroleum fuels.

June 23, 2010 Advisory Committee Meeting

- Advisory committee members also want to talk about indirect effects other than indirect land use change.
- All fuels have indirect carbon effects.

Summary of written comments from advisory committee member or alternate June 25, 2010

- Under an intellectually honest system –if we are going to review indirect land use for biofuels – which in reality is expanding the system boundary of the lifecycle analysis to include economic market mediated impacts…. Then we have to look the lifecycle analysis expanded boundary for all fuels… because all fuels have an economic market mediated impacts. It is my belief that Oregon will be well served to let the science develop on all fuels before including any number for any fuel and certainly it would be unwise and scientifically unjustified to burden one fuel with an indirect impact if we are not burdening other fuels with their specific market mediated impact.

August 5, 2010 Advisory Committee Meeting

- CARB's ILUC numbers were used in all scenarios, except for the scenario that does not include indirect land use change.
- The economic analysis will be looking at what would happen if we didn't use any ILUC number, and what would happen if we used the highest, to bound the possibilities. Preliminary results are scheduled to be presented in October with an opportunity for committee members to give input, and final results will be presented in November.

- I would like to put a proposal on the table now. Since equity requires us to look at not only the numbers for biofuels but also look at petroleum and other factors that are not considered in petroleum. And as we know the science is in its infancy, and we are making guesses that do not do justice to our efforts, and keeping in mind that the real work (towards GHG emissions reductions) is back ended, it might be a legitimate approach to give ourselves two years before making a decision to see where the science advances, and use an ILUC number of zero for the time being. *Response: This is the approach that Canada took. Washington is taking the average of all available ILUC numbers currently in use.*
- Did someone from California say they did it both ways? ***Response:*** *Yes, California also ran their scenarios without indirect land use change, and the volumes of fuels only changes between either two or four percent. Our scenarios will be different from California's.*
- Intellectually, these other approaches offend me, because we're talking about trying to attribute conversion of land to soybean crops in Brazil to the LCFS, when it's just as likely that the conversion is due to the production of McDonald's hamburgers. We're trying to measure things we can't control and that are outside the bounds of our science.
- Clearly there are ILUC impacts, even though we may not agree on what the actual numbers should be. We need to incorporate the best number that we have today, so let's use the best numbers we have today, and review them in the future.
- We're using 2010 as the baseline going forward, but yet there has been a lot of investment in and biofuels used in Oregon from 2006 forward with the biofuels mandates, so we're not recognizing those investments and contributions to the (LCFS GHG emission reduction) target, so it might be more appropriate if we move forward to use a 2006 baseline instead of 2010. What does the statute say with regard to where to start from? ***Response:*** *I think we have flexibility in the statute. It does state 2010 to 2020, and the net effect of what you are saying is that we would be shooting for less than a ten percent reduction because we would already be counting some historical reduction so we would get less than 10% going forward. We could start with a 2006 baseline and go for a 12% reduction and get to the same effect, or go with an 8% reduction in 2010, just go with what we've got.*
- When you go from a (ILUC value of) hundred to fifteen in a matter of years looking at this complex issue, it highlights how challenging this is from a scientific/modeling point of view, and the sensitivities of the inputs and assumptions that are involved, so there is still a lot of work to be done. What is missing is a measure of the indirect effects of petroleum (production), so what we've got right now is an analysis that is being refined for quantifying the indirect effects focusing on biofuels, but there's not been an analysis on the indirect effects of petroleum, so that's another reason to wait until that is done more authoritatively.
- If we were to make a commitment to formally evaluate the science around ILUC numbers say in two years, would that work for you? It's an improvement over trying to make a guess as to what they are today, but I would like to ask the scientists in the room (if there are any) if we can expect something from the National Academy of Science or other entity? *Response (attendee): The national Academy is looking at the role of sustainability and environmental issues, so the modeling aspects aren't necessarily going in the direction you are proposing. But the EPA and CARB are working on this issue.*
- None of the scenarios include indirect land use change for conventional fuels.
- ODA would go on the record as having the position of favoring waiting until the science evolves. Foreign government laws, policies and incentives have a much bigger sway on what is happening in terms of their crops than do biofuels, that I think to take the best numbers available now would be taking a number that could use further refinement.

- CARB has done the analysis on the indirect land uses for petroleum and petroleum products. The question right now is that some folks have suggested other numbers that CARB does not agree with, and that is what is being debated currently.
- CARB may have done an analysis of indirect land use, but has not analyzed indirect effects, and there is a lot of contention around that.
- There is a lot of criticism of the oversimplification of the information used in the CARB process.
- ***Response (DEQ):*** *I tend to think in terms of the practicality of programs and what the outcomes will be, and under any compliance scenario under the LCFS, biofuels will play a significant role. One of the big factors that we have to address is the current EPA limit of 10% ethanol in gasoline unless you go to an E85 vehicle, and the E85 infrastructure. If we don't have an indirect land use factor, what will probably end up happening is we will end up with more corn ethanol or cellulosic ethanol if it becomes available than we would have otherwise had. In either case (with more corn or cellulosic) ethanol, we're probably going to be creating an incentive to create that E85 infrastructure, and that is what is needed in the long run. From a practical standpoint, if we don't use an ILUC number, we are still going to get a lot of the benefit of building the E85 infrastructure that we will need later on if it turns out that there is an associate land use effect and we start shifting more towards cellulosic ethanol, so there is still an advantage to include ILUC at some point, even thought there is still uncertainty about what ILUC numbers should be used today.*
- So if you don't assign one now but when the science is better to re-evaluate, in 2013, the regulated parties will need some sort of regulatory certainty as to what their compliance obligations are.
- I think that we need to acknowledge that it's a real phenomenon. It's one thing to say it's a zero number, and another thing to say it's a real phenomenon that we think need to be worked on, and we will include a number a certain future point in time.
- Another option to go forward could be to start with a low number (i.e. the Purdue number) and use it until we have a better number.
- From our perspective, (WSPA) thinks that land use should be included, and that is reflected in the written comments we submitted.
- Waiting until the science around ILUC numbers evolves is a good idea, but I'm hearing a discussion about a singular number, when reality will be a suite of ILUC numbers that will be assigned to each appropriate fuel, so it is important to recognize that value in waiting to assign ILUC numbers to any particular fuel until ILUC values are available to apply to all fuels in question. ***Response:*** *Yes, individual ILUC numbers will be assigned to different feedstocks. It may be that not all will be assigned at the same time.*
- Is seems like the scenario that would be the most sensitive to it would be the scenario with and without the ILUC number. ***Response:*** *The one that would be the most sensitive and includes the most conventional biofuels is the compliance scenario that will be modeled with and without ILUC.*

October 7, 2010 Advisory Committee Meeting

- The National Academy of Science has announced that they are going to do a comprehensive analysis in 2012, but it is unclear what comprehensive means and how it intersects with what the CARB working groups are doing.
- I would be interested in learning what groups are working on the NAS effort that aren't on the CARB working group.

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- My understanding is that the NAS study will look at indirect effects, not just land use change.
- What is the timeline for the CARB 2012 review- will it be finished by the end of 2012? ***Response:*** *The CARB expert workgroup has to report to the CARB Board in the beginning of 2011, and CARB Board will have to act on it and CARB would then have to incorporate any changes after that as part of their 2012 program review. I do not know when in 2011 CARB would make changes to their ILUC numbers.*
- In a previous discussion we'd talked about rolling in any indirect effects- is that correct? ***Response:*** *We discussed incorporating any changes to ILUC numbers after a program review.*
- With continued research, the trending of ILUC numbers seems to be a decrease in ILUC values. The ranges of the numbers out there really illustrate how competitive ethanol is to gasoline in terms of the carbon intensity of the fuels.
- One consideration to make is having a process where scientific data, such as ILUC numbers can be updated and corresponding changes to the standard can be made outside of a formal rulemaking process. This would allow for a more timely updates to carbon intensities.
- If ILUC is not included in the rule initially, a rulemaking would be necessary to include it in the LCFS program at a later date. Building an administrative process into the rule up front would provide a means for updating and/or adding indirect effects in the future as better information becomes available.
- There will be a process for setting carbon intensities for different fuels and fuel pathways, of which the ILUC value is a subset, and every time the ILUC changes, would you need a new rule for a new fuel pathway? ***Response:*** *There will be a lookup table in the rules that will have carbon intensities for associate fuels. According to the advice DEQ has received from DOJ, if we have a pathway that applies to anyone, it has to be in a rule, but we can by order (by Department action) have a unique pathway, so if a new product comes out between rulemakings then we can create a carbon intensity value for that fuel and incorporate that pathway into the rules the next time the rules are update, But if there is a ILUC that needs to be added that would apply to all fuels, that would require the change be made via a formal rulemaking process.*
- This has such a potentially large impact on the whole program and there is still a lot of work going on, rather than picking a time-certain date to incorporate ILUC values, it seems more reasonable to incorporate the numbers at such a time that we have confidence in them and there is consensus as to what ILUC numbers should be used. ***Response:*** *DEQ isn't committing to a specific date, just trying to identify a general timeframe when we can revisit the issue and make a decision. DEQ is currently considering including the lookup table without ILUC numbers, with a note that ILUC numbers may be incorporated at some point in the future. We have various reviews built into our program, the first in late 2013 or early 2014 and the big one in 2016, and either one of those would be a good place to review the data and add the ILUC if we were to conclude that the science had evolved to a point where there was sufficient certainty in the ILUC numbers such that they should be included in the LCFS program to calculate carbon intensities of fuels.*
- Or you could conclude that they shouldn't be included because of investments already made. ***Response:*** *Potentially, but you would need to review the information first.*
- We have to realize that while there is still uncertainty about what ILUC values should be used, it is inaccurate to say that not including the ILUC data is a scientific approach. Not including that data is just as much of a decision as choosing one of the current methodologies. We need to send the low carbon fuels market the message that we will be adopting the best available science at a certain time so the market can adjust and prepare for that. I think having a date certain decision point takes the politics out of the debate as to what the best available science is and which data set and/or methodology to use.

Response: *As a practical matter, we can provide a date certain recommendation to the Commission, but we cannot commit that the commission will take any action in the future. It's a trade-off between incorporating a big moving target now versus the uncertainty of not having anything for a while, and it is important to look at it at a time certain point to review it. By not picking a set of ILUC numbers now, DEQ is not saying that indirect land use change does not exist, but that there is not enough certainty at this point about what those numbers should be to include them in the rule initially.*

- From the perspective of a fuel producer, is it better to err on the side of caution by setting a larger ILUC value now and potentially lower it later if need be?
- I strongly suggest rolling the indirect effects recommendations into the 2013 program review for Commission consideration. That would give regulated parties certainty time to adjust and implement. During the first years of the program, this will affect a relatively small amount of fuels that will be obligated to comply.
- Having the ILUC in the rule from the beginning would favor lower carbon fuels faster. By making the choice not to include ILUC initially, it would delay the buildup of lower carbon fuels because you're decreasing the differential between conventional biofuels and where we hope to go with lower carbon fuels. That is a real impact, especially when the difference in some of the ILUC numbers out there is taken into consideration. There needs to be a date certain time to incorporate an ILUC. What is really important is that the message sent to the market is this ILUC matters and the values will be adjusted over time. ***Response:*** *It may be helpful to have a column in the table reserved for ILUC with an asterisk indicating that it has not been established but will be included after the program review selected.*
- If and when we add an ILUC we would have to then adjust our baseline starting year to recalculate the carbon intensity of blended fuels. Credits that were generated and banked prior to the incorporation of the ILUC could be adjusted after the ILUC is incorporated.
- The Renewable Fuels Standards help us achieve our greenhouse gas reductions goals during the early years of the LCFS program, and we are more concerned about the later years, and this dampens the supply in the later years. Banking credits is potentially a big issue, and compounds the effects. The RIN system has dealt with a similar situation, and the rules in that program state that credits generated in the initial years of that program are only good for a certain amount of time, and credits could be allowed to accumulate after a certain amount of time. ***Response:*** *One possible approach would be to say the credits generated before the year 2013 have a lifespan of 3 years, people would be aware of that fact going into the program. What would be the effect of that type of an approach?*
- That is a good idea because it creates certainty.
- The shorter the time period that those credits are good, the less value they will have. ***Response:*** *It would reduce the incentive to generate early credits, but as was stated earlier, RFS is already providing incentives in 2011-15, so it might be a good trade-off.*
- That seems like a valid approach.
- That would provide certainty to the process.
- WSPA thinks ILUC should be included in any proposal that goes forward, but does not have a recommendation for which ILUC numbers should be used at this time.
- (Dwight Stevenson from Tesoro – on the phone) Speaking for Tesoro, choosing to ignore any indirect effects, you are effectively saying that the indirect is zero ,and there is not effect of taking food out of the food chain for the production of fuel, and that will over stimulate the use of biofuels. You want to pick your best estimate and use that, and adjust as appropriate. The effect of using biofuels or conventional

fuels will be best regulated by using your best estimate of the carbon intensity out there. My recommendation would be to use CARB's numbers because they are the best vetted ILUC numbers.

- Several members of the advisory committee, DEQ and chairman Reeve thanked Jeff for helping the committee better understand the approaches being used to estimate indirect land use change effects.
- *We talked about how credits might expire, but some credits may not need to. For example, credits generated by the production of fuels made from waste won't need to be updated because the feedstock is a waste product. The idea of letting credits expire just came up in the discussion of today's meeting, so we should think about that more.*
- (Tesoro, on the phone): There are three things that happened when you take crops and turn them into fuel 1- food becomes more expensive and people will eat less of it, the amount of fertilizer and water used on crops to increase productivity, and therefore more land will be put into food production, which is the indirect land use effect. What hasn't been discussed yet in Oregon is the farming intensity. There is some effect from putting more fertilizer on the ground and increasing N20, increased production costs for fertilizer, and increased water use and the effect that has on the displaced uses for the water used to irrigate more crops used for fuel. The CARB analysis showed that about half of the effect was from new land, and the other half was from the price signal that pushed the market. The carbon intensity would tend to increase the carbon intensity of crop based fuels.
- *Do you know if that has been discussed in California or elsewhere?*
- Yes, it is being discussed in California. ***Response:*** *It seems unlikely that we will have all the information we need by 2013 on indirect effect, because ILUC is different for each fuel pathway, but we should have enough information to make a decision about indirect land use changes, but other indirect effects could be taken up during the 2016 legislature or potentially beyond that date.*
- Concerns also exist in the marketplace regarding the indirect effects of petroleum production. And those studies are likewise underway. I would like to respectfully disagree that the early CARB GTAP methodology is the best vetted study to help determine the appropriate ILUC values to use.
- As we move forward, at some point there will be an incorporation of ILUC in the economic analysis. If we are going to go forward without an ILUC number the first few years of the program, will it be included in the model used to generate the economic analysis. ***Response:*** *Mike Lawrence of JFA will present the effects of lower carbon fuels and compare the changing attributes of the compliance scenarios to demonstrate how they affect the economics.*

Summary of written comments from advisory committee member or alternate December 1, 2010

- We strongly agree with the recommendation to wait until the science is more firm regarding indirect land use effects before including any value.
- We want to make sure that no iluc is added for biofuels without a corresponding indirect effect analysis and number for all fuels since all fuels have indirect effects. It is important for indirect numbers for all fuels to be added at the same time.
- The LCFS was adopted with the recognition that a lifecycle carbon analysis of fuels needs to be taken into account. This is a primary distinction between the LCFS and renewable fuel standards. This lifecycle analysis assures that undesirable impacts like land conversion and tropical deforestation are limited. Indirect effects should be incorporated at a date certain with the best available science at that time. Environment Oregon previously co-wrote a letter to DEQ regarding this subject. We continue to stand by the comments provided in that letter.
- DEQ's approach to indirect impacts, including indirect land use change (ILUC), associated with low carbon fuel production demonstrates the evolving science and understanding of this complex issue. We

strongly supports DEQ's recommendation that indirect impacts not be included in the LCFS at this time in order to allow for further scientific study. The California Air Resources Board (CARB) recently acknowledged that previous ILUC estimates were incorrect and has proposed to lessen the ILUC impact in the California LCFS. DEQ has proposed a reasonable solution to re-examine the science of indirect impacts in 2014, and, if necessary, in 2016, in order to accurately account for potential indirect impacts.

- Recommendation: it is important to evaluate indirect impacts for all fuels equally including liquid fuels, gaseous fuels, electricity, and all other fuels so as not to disadvantage a group of fuels compared to others. It is not until the science is well understood for all fuels that any indirect impacts should be included in the LCFS.

3. Energy Economy Ratios

December 3, 2009 Advisory Committee Meeting

- Commenter interpreted reference to drive train efficiencies in HB 2186 to mean the committee would be looking at vehicle improvements such as CBT transmissions for heavy duty trucks, rather than the efficiency of all vehicles which use a certain fuel.
- For each fuel, there will be newer efficient vehicles and older, less efficient vehicles on the road. Did California look at just what is on the road now, or did they also project future vehicles? ***Response*** *(CARB): The fuel economy of alternatives to gasoline was compared to gasoline vehicles, while alternatives to diesel were compared to diesel vehicles, using existing data from existing vehicles.*
- California's analysis did not compare gasoline vehicles to diesel vehicles, so it doesn't take into account that diesel vehicles are more efficient. Request to pick this issue up in more detail, especially with reference to whether we want to encourage a switch from gasoline to diesel in the passenger vehicle market to get GHG reductions. ***Response*** *(CARB): California separated gasoline and diesel in order to provide incentives for improvements in both fuels.*
- Commenter wants to use California format and update it over time (i.e., gasoline and diesel are always normalized to one, and the EERs for other vehicles are considered relative to gasoline and diesel, and expressed as multiples of gasoline and diesel).
- Will the analysis account for urea injection technology in diesel engines? This technology will be here for heavy diesel next year.

January 23, 2010 Advisory Committee Meeting

- Isn't considering EERs adding conservation into the LCFS, which goes beyond considering carbon intensity of the fuel? ***Response:*** The EERs are intended to put different fuels on an even footing by taking into account the energy that gets to the wheels and moves the vehicle, not simply the amount of fuel energy in the tank. The LCFS rule would not try to change the efficiency of vehicles using any type of fuel, but to account for differences in drive train efficiency.
- What happens if the drive train efficiency of a class of vehicles improves over time – do we need to recalculate the EERs? Another dimension is how often the baseline will be updated, i.e. if drive train efficiency increases for gasoline, the baseline would need to be adjusted in order to preserve the technology-forcing nature of the LCFS with regard to fuels.
- Commenter is afraid the committee is confusing energy content of the fuel with the ultimate use of the fuel.

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May 20, 2010 Advisory Committee Meeting

- With regard to the EER for electricity, the 2016 CARB rules are going to apply to cars sold in 2016, which is tiny portion of the existing fleet in 2016. ***Response:*** *My impression is that there was not an accurate attribution made to exactly what the fleet is going to be. There have been rules that increase the efficiency up to 30%. So new cars as of 2016 will be 30% more efficient on average and by that time, from then on, it is going to be the latter half of our low carbon fuel standard when we will start to accumulate more and more electric vehicles. So that is assuming that that is going to be the dominant effect by 2022.*
- Roughly speaking the fleet turns over in about ten years and so about 10% per year, so in 2016, if 10% of the cars will be 30% more efficient so it is overall 3% for the fleet and in 2017 it will be 6% of the fleet and so it will phase in and it is not 30% yet. We are ramping up towards that 30%. So they are probably penalizing electric vehicles in this calculation. Is that correct? ***Response:*** *Yes.*
- An EER of four is more accurate now, rather than three. We are using a value of three here for the EER, which turns out to be very significant in the carbon intensity calculation. And we know that four is right currently, and we know that three will be right sometime in the future, so why are we using three? ***Response:*** *It is a much closer match to the future conditions. However it might be possible to use an EER of four in the first year, and then have it decline linearly until 2022.*
- In support of the EER of three: the standard for the next new vehicle coming out is going to be a three.
    - But that won't be the fleet until ten years from now and then the three will be correct.

Summary of written comments from advisory committee member or alternate July 12, 2010 regarding draft compliance scenarios presented at July 7, 2010 advisory committee meeting

- At slide 26 addressing EV EERs, the 122 mi/gal Oregon assumption for PHEV/EV is in the CARB ballpark (119 mi/gal), but additional information on EV fuel economy appears to be coming from USEPA in August when it plans to publish in the Federal Register its proposed Revisions to Motor Vehicle Fuel Economy Label (RIN: 2060-AQ09). I'd like to see that information inform our analysis.

Summary of written comments from advisory committee member or alternate July 21, 2010 regarding draft compliance scenarios presented at July 7, 2010 advisory committee meeting

- Drop scenario 3 and do not devise any new scenarios that do not include ILUC. Even if there is ultimate disagreement on the ILUC numbers used, I think not including ILUC is not defensible.
- Include RFS2 proportionate share in BAU case for both Ethanol and Biodiesel. It seems realistic that Oregon will be in the middle, neither exceeding nor being willing not to meet its proportionate share for RFS2 compliance. Therefore costs associated with developing infrastructure, etc, can legitimately be considered outside of the LCFS.

VIII. Compliance Scenarios

2. Fuels Assessment and Biomass Assessment

January 27, 2010 Advisory Committee Meeting

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- A lot of biogas CNG is getting "locked up" for electricity generation in order to comply with the state Renewable Portfolio Standard.

April 15, 2010 Advisory Committee Meeting

- Are EPA's RFS2 biofuel goals based on an assessment of bio-feedstocks such as biomass waste or biofuels crops? ***Response: (DEQ)*** *Yes, They have a whole chapter on biofuels feedstocks available nationwide (Chapter 1.2 of EPA's RFS2 Regulatory Impact Analysis).*
- Lane Counsel of Governments is studying diverting grass straw from other markets. There is a large portion which doesn't have feed or other value. Annual rye, for example, is not in demand from the Asian market. The material is being restrained from being burned. They are having storage difficulty in most of the Willamette Valley, which is driving the price down. The market is highly volatile, anywhere from $12 to $45 per ton. You may have to do a study that looks at projecting the cost out into uncertain market demand conditions.
- Some portion of material is going to Asia as raw boiler fuel. We probably can do something here with it and compete on price.
- On liquefied natural gas (LNG) use in the compliance scenarios: I think not including LNG is unreasonable given the trajectory of growth and the fact that the technology is heavily commercialized for medium to heavy vehicles in particular. It is probably reasonable to include zero in the low compliance scenario, but given the trajectory of growth in transportation LNG use and the fact that the technology is well commercialized for medium and heavy-duty uses, it is unreasonable to count zero LNG contributing to compliance across all of the scenarios. Therefore, I think we should reconsider that and include a scenario with a high LNG estimate, and potentially a moderate as well.
- This is based on EPA and (California's) analysis, both of which are in a dynamic process, which means that things are continually changing.
- Some of these fuel volume minimums and maximums would be competing for the same feedstock. ***Response: (DEQ)*** *That would be taken into account as the compliance scenarios are developed.*
- The high case for biofuel is understated because it assumes that all 50 states are competing for low carbon fuels. The high case should assume that we would have more biofuels than we produce in Oregon.
- If you look at California's analysis, we are not going to get to where we need to get on the low carbon fuel penetration with our existing fleets. So it is relying on high infiltration, whether it is E15 or flex fuel vehicles or more compressed natural gas cars. The actual infrastructure is not there. If we really want this thing to work, we are going to have to address the vehicle side of the equation, in terms of supply. I do not know how to do it, but that point should be made.
- I just wanted to frame the agricultural residue collection aggregation a bit. For a small scale commercial plant you are looking at say 20-25 million gallons, and that is what the early ones are being proposed at. You are talking about between 300,000 and 500,000 (gallons). This is by far the largest aggregation of agriculture biomass in the history of the country. So the reason that feedstock cost numbers are not firm is that no one has ever collected material at that level.
- One of the benefits of the flexible fuel vehicle is that you do not have to blend all the way to E85. You can use 50% ethanol. Will there be changes in engine technology which would overcome some of the energy density penalties that you have with ethanol? I mean obviously all the (existing) engines were designed for gasoline and not for a higher-octane fuel. ***Response: (Wybourny)*** *The first question, let's say that instead of going all the way to E85, you go to something like E50. It may be the pricing of E50 could be closer to gasoline and it helps you in terms of pricing for a high price ethanol and E85. The*

challenge there is that then you need to have more vehicles using E50 to use up the ethanol. The second question: I am not a vehicle specialist so I cannot answer that.

- Butanol is much more transparent than Ethanol. What is the legal ability to use Butanol as a fuel and what about the intellectual property for producing Butanol? ***Response: (Wybourny)*** *I know that companies are talking about actually taking existing corn ethanol plants and converting them over to Butanol.*
- Can butanol legally be used as a transportation fuel? ***Response: (Wybourny)*** *Yes. The problem is that butanol you can blend at the refinery, but you have to make sure you keep it segregated from the rest of the gasoline pool, because the rest of the gasoline pool is all blended with ethanol.*
- DuPont has a biobutanol project as well. I feel comfortable that the economics are going to work out.
- Could you comment a little more on infrastructure issues and using E50 in the E85 vehicle? ***Response: (Wybourny)*** *There are issues about trying to even use E85 because you have a fuel that is too low in Reid Vapor Pressure. One way forward is that you have butane at every terminal to blend that in. But then you force all of these terminals to have butane spears, which is a challenge in itself. The ASTM committee is likely to allow for lower blends of ethanol less than E85 so that you can meet the vehicle pressure minimums for the ASTM standard for E85. Now how would you use E85 at the pump? One way is that you could have E85 and then you could have the blending pump. You could blend the E85 with gasoline and have a mixture that is less than E85. I am not a distribution specialist. Our distribution person has looked at this a lot.*
- Why aren't you testing off road equipment for E15? ***Response: (Cleary)*** *Earlier than the year 2000, we have some concerns with using E15. We believe that the tier two vehicles were designed to be more able to adjust the blending ratio (with air) to accommodate a lower blend mixture than an E15 would present to the engine. With older cars, we would probably have to reserve gasoline pools so that they would be able to use something less than E15. They are flexible enough to handle E10. In most cases, they are not capable of using E15.*
- If we do not make this change to E15 until we satisfy all of the non-road small engines, outboard motors, etc. we are letting the tail wag the dog. The huge amount of volume has got to go into transportation vehicles and my personal opinion is that it is time for the small internal combustion engine manufacturers to come into the 21ST century when it comes to being able to use other than true gasoline.
- I would actually agree with you on that statement. However, being on the front line of retailing fuel products, it would be tremendously helpful to have research that we can turn to. ***Response: (Wybourny)*** *Clearly, there has to be some changes in the design, etc. to small internal combustion engines. They are way behind the curve compared to the vast amount of internal combustion engines used for transportation. If necessary, then one of those pumps will just have to be gasoline with no oxygenates in it and then I guess the marketplace will decide at that point.*
- Currently in Oregon, E85 is actually priced on an energy equivalent basis at the pump. And you have a 42 cent a gallon state tax credit. The economics of it, for an individual consumer, is favorable. I would say that one of our barriers is the perception of ethanol and E85 in the marketplace, but also people buy flex-fuel vehicles (FFVs, which can run on gasoline or any blend of gasoline and ethanol up to E85) and have no idea that they have a FFV. We run into that all the time where we are telling people, you know you could be saving 90 cents a gallon right now because you have a FFV and they are completely surprised.
- There needs to be some work done by the EPA to accept butanol. As for somebody patenting the process, I think the answer is yes, they are.

- DEQ is considering not including algae fuel in the compliance scenarios, but EPA did have a number for algae in RFS2. How did you come up with that number and would you recommend that Oregon include a proportionate share as we move forward in looking at biodiesel as a future fuel for Oregon? ***Response:*** *(Wybourny) I really do not know what number we came up with for algae. We talked to individual algae companies and got some information from them. NREL did a study for us and they estimated, the energy needs, production volumes of different algae technologies, open pond, etc. and we assessed the life-cycle impact based on that.*
- If you were giving these talk four years from now how optimistic are you that cellulosic ethanol and diesel would be working? ***Response:*** *(Wybourny) Clearly, there is a tremendous amount of effort working on modifying the pathway and from there to drive that sugar into more hydrocarbon rich molecules. We could try manipulating the fatty acid pathway, again, starting from sugars. The issue is they are heading to Brazil to use sugar from sugar cane. So, I still believe the crux of the matter is, are those organisms productive enough in their synthetic capability, are they going to be able to handle and manage the a lot dirtier intermediate sugar that come from the production of the intermediate for liganocellulose. Therefore, I am confident, as I am a technologist myself, that they are going to be able to engineer these organisms and they are going to be able to meet some economic targets based on sugar. The real question is can use sugar derived from liganocellulose.*
- There are challenges to each of these technologies and just because you have developed a technology in the lab and demonstrated it in some sort of a simple pilot plant does not mean that it is going to work on full scale. It is a very challenging pathway for any of these technologies. I think it helps that DOE is funding to offset some of the capital costs and some of the development costs as well as the USDA's funding. We have the renewable fuel standard, which requires that the fuel is available and has to be used. I am very optimistic that we are going to see a lot of cellulosic biofuel being produced, but it is a slow start because there is a lot of development work that has to happen before you commercialize.
- We have to disabuse ourselves of these zero emission vehicle annotation for electrics. They are relocated emission vehicles. Nighttime charging is not gas, it is coal.
- It is zero emission at the tailpipe, but in the lifecycle analysis it is not zero emission. There is an emission impact in generating additional electricity. ***Response: (DEQ)*** *When we are talking about other pollutants besides greenhouse gases, the location of the emission is critical. We tend to have issues with ozone in our urban areas. Therefore, when we say zero emission vehicles, we are primarily talking about tailpipe in terms of an ozone strategy. In terms of climate change, the lifecycle analysis will capture all of this. It will take into account the emissions from power plants and the efficiency of electric vehicles and see what the benefit is.*
- When will the economic analysis be able to look at those other benefits of local air shed?
- Are you going to address how much capacity is going to be required for these charging stations? I would like to see some information on constraints on where we can generate capacity. ***Response: (DEQ)*** *I do not know if we have that quantified, but hopefully Maury will able to address the capacity of the grid to accommodate electric vehicles. In May, we are going to be taking on these and issues related to the carbon intensity of electricity and who the opt-in parties will be.*
- Have you done an estimate for the gas taxes that will be avoided by using electric cars? ***Response: (James)*** *Obviously as an ODOT person, we want a gas tax. There has been a pilot study on the per mile charge which will be part of the conversation going forward. Charging stations are equipped with the technology to read miles.*
- Since electric motors can generate a lot of torque that there is hope and promise for use in heavy duty applications. ***Response: (James)*** *Yes, they are available. You are right about torque.*

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- There is actually an electrical application on air travel in of Los Angeles and Long Beach.
- What issues that might arise from commercial establishments providing charging infrastructure for electric vehicles? Will they become utility providers under the regulation? And at what level will they charge an extra implement? ***Response: (Galbraith)*** *In general, there is a prohibition in this state on the resale of retail electricity. In other words, it you purchase power from Portland General Electric, say if you are a MacDonald's and you purchase power from Portland General Electric, there is a prohibition on you reselling that power to someone else. Now that statute does have a provision in it for electric vehicle charging and exempts electric vehicle charging stations from falling into the regulation of PUC. Other issues include off-peak charging incentives, metering issues, data collection issues, battery deployment, utility investment in batteries, and stranded cost issues. We are an economic regulatory agency who sets rates. We have a stimulus grant to hire some utility analysts to try and avoid becoming a bottleneck to doing these innovative things. We've got an investigation open and we would love your input on what issues need to be tackled.*
- To develop rates that encourage off-peak charging could be perverse based on the incentives and objectives we have here because of the mix of our nighttime fuel supply. Do you have any time of day related carbon analysis that has been done? Many base load power plants are coal. ***Response: (Galbraith)*** *That information could be gleaned from utility integrated resource plants. There is a perception out there that you need to distinguish between the generator that is on the margin and the generators that are just running around the clock. And your point is that there is a lot of coal fire generation that runs 24/7, that is just always running. But, if you are looking at what the marginal resource is, for the majority of the off-peak hours, it is still a gas-fire turbine. It does not mean that coal is not running. The coal is running, it is just not marginal. It is not what will be turned off next if you were to decrease that.*
- That cautions us about treating different fuels different ways, because the next new marginal kilowatt hours may be different than our base load characteristics of the carbon in our petroleum and so we want to make sure that we are not always looking to that next new marginal, but we are looking at the carbon contribution currently. ***Response: (Galbraith)*** *I think you want to look at carbon intensity at different times at different seasons of the year.*
- How much non-intermittent resource needs to be added to support the intermittent, because that in some ways may represent future marginal supply. ***Response: (Galbraith)*** *It is an issue that has been under discussion for several years now and it will continue to be under discussion. So it really goes to how much flexibility, because what we are talking about here is being able to ramp generation up and down when the wind is either falling off or rising. We want to go in the opposite direction of the intermittent resource. How much flexible generation do we currently have and when might we run out and when we run out what do we want to add to get more. In my mind, those are the three questions and the answer to any of those questions is still unresolved. We really do not have a real clear sense as to how much current flexibility we have in the existing system. Bonneville has taken a look at it and said they are getting close to the point where they are going to run out on their system. But you need to remember that Bonneville has the vast majority of the wind on its balancing authority today. There are other balancing authorities in the Pacific Northwest that have not reached the level of wind penetration that Bonneville has. It is an open issue as to how much flexibility we currently have, how close we are to running out of it, and what we need to do to get more in the future.*
- To put this in context, with 11,000 cars at 130-140 kilowatts a piece, if they were all charging at once that is 1.4 megawatts, that is a very, very small proportion of our average statewide connected load.
- One of the electric utilities about the effect on rate payers of added capacity in order to support the added load from electric vehicles. Specifically if imposing added load costs across from the base rate payers

and whether that would allowable and how that would be balanced and whether there would be rule changes? Is PUC was doing investigation into that issue and how to resolve it? ***Response: (Galbraith)*** *It sounds like you are referring to a provision in our statue that is called the The Used and Useful provision that means the investments by the utility, if they are going to be recovered in rates, must be Used and Useful. There are two aspects to the Used and Useful situation. The traditional application of it in utility regulation is that at the end of the investment's life it comes out of rates when it has run its economic life and is no longer useful. I think the application of it in this case would be at the front end of the life, where the utilities make some initial up-front investment to kick start electric vehicle adoption. Get the charging stations out there, take care of the range anxiety and I think that people are wondering if the Used and Useful standard is going to be a barrier to doing that. In other words, if the stations are put in and you do not get a large adoption of electric vehicles and the utilities are trying to recover those costs, is that Used and Useful standard going to prevent that.*

- Utilities have an obligation to serve on a peak day because wind is an intermittent resource they have to back up every megawatt power of wind with something else. From a peak day perspective, wind delivers no energy from a planning perspective. I do not know if that is how every utility treats it, but that is one approach to the whole notion of how we back up these intermittent resources. To your question, what other resource is there scalable available to utility than natural gas? There is no nuclear, coal, and probably not much hydro. What are going to add for capacity? ***Response: (Galbraith)*** *I think you are correct that our options are becoming more and more limited on what we can add for capacity. I think that for the short term you are talking natural gas resources. There are other options out there. People are taking a close look at pump storage and other resources, but they have very long construction lead times. It is not something that you can bring on line the next two or three years, but more like 10, 12 or 13 years. On the other point about what for every megawatt hour of wind capacity that you have, you need to have a backup; I do not think it has to be megawatt for megawatt. It does not have to be equivalent, because there are some utilities that are currently surplus on capacity or they are already short. It is really the surplus sources that are the most interesting, because they are the ones that you don't have to add megawatt for megawatt. They already have a cushion in their system.*
- Say demand could stay still for a minute. Adding wind does not demand more capacity. It is actually increasing capacity. What might have been base could go to firming up a renewable or an intermittent. If we can get a cap on that demand, then adding wind does not build to it. You are subtracting more than you are adding.
- How will you temper any of your estimations for computation between electric vehicles and hybrids, and what if people say they are very likely for my next car and, then they do not buy one? ***Response: (Beard)*** *It is a great question and Portland State in partnership with a number of folks is trying to understand the difference in the sociology, the anthropology of these cars. So if you turn around and you get a battery electric Nissan Leaf that goes 100 miles, it may not be ideal to then have to use an internal combustion engine to regenerate power to the battery, but it is a lot less worse than running 100% combustion. We do not know yet what the use cases are and how the market will respond, but we are simply trying to give our citizens choices and learn what makes sense. We are going to jump heavily into light duty urban freight mobility as well.*
- How collated is this to the uptake curve of hybrids? In Oregon's history, hasn't the hybrid market share satiated some of the enthusiasm for the electric vehicle? In addition, if we have a six-year turnover, aren't those people's appetite for next generation technology met? ***Response: (Beard)*** *I am going to qualify it by saying, I am only speculating here. But, because of the powers of natural selection, the early adopters who bought Prius in Portland and elsewhere in Oregon, we are beloved by Toyota. They think that Portland is the coolest place in North American. The Nissan people will turn around and say you know*

what in our polling we found out that there is a lot of motivation to go from a hybrid vehicle to a pure battery electric vehicle.

- There is interest in electric vehicles in rural Oregon.
- DEQ did similar calculations as far as projecting high and low estimates. If we were to hit 20% new vehicle sales by 2022 and we went straight up from zero to 20% in these sales, I (Dave Nordberg) come out with a figure of about 129,000 vehicles on the road by 2022, which is not far off from his high estimates. On the low estimates, if we went to 5% of new vehicle sales by 2022 that would seem subjectively to what might be a conservative approach to a low number of electric vehicles. That is highly subjective.
- How much gas is currently available and how many natural gas vehicles would be available? ***Response: (Campbell)*** *Natural gas is distributed throughout the country. In 2008, we went from 120 years of proven reserves to about 200 years of proven reserve due to the efficiencies of being able to pull and extract that gas out of the shale.*
- Due to a new production technology that gave access to these vast reserves of shale, everything is on its head in our industry. We are not talking any longer about a resource that is in short supply, but rather one that is clearly abundant, clearly available, clearly domestic, and clearly North American produced.
- What safety issues are there with natural gas used for transportation? ***Response: (Campbell)*** Natural gas vehicles are very, very secure and safe. Every three years you have them inspected, because you are fueling with high-pressure systems.
- Shelf gases might have indirect land use affects or impacts that have not been assessed on a carbon basis. In addition, water use has rarely been addressed. The other issue is if there is so much shale around and it is $6.00, how does that biomethane play practical if it takes $8.00 to get it to market? ***Response: (Campbell)*** When you are talking about the contamination of aquifers it is not even at the same drilling level. The depth of what we are doing is vastly significant. You do not have that kind of cross contamination of water with shale exploration. There is water used, but the industry is reusing about 60-70%.
- If shale gas costs $2.00 more to get it out of the ground, the assumption that the cost has no energy content to it, is curious. I just want to see the math. ***Response: (Campbell)*** I think that a fact that we have realized or recognized is so much gas that the price of the market went down to $4.00 and could possibly go down to $3.00. However, then the price will rise back up and you will see the race go and you will see the price go back down again.
- A headline in the Wall Street Journal about a week ago says that the Energy Information Administration has not been collecting shale gas production data all that well and that the price of natural gas may be depressed because of that. We have two gas experts here. Is there a shale gas bubble that is about to burst here? Are we about to learn that the Energy Information Administration has been dramatically over-estimating shale production and we are going from $4.00 gas to $6.00 gas in matter of weeks? We went down once. Are we going back up? ***Response: (Campbell)*** I think the Energy Information Administration has been a horrible agency in terms of projections. I am not worried about one article or what the Energy Information Administration thinks in terms of what this country has in terms of supply because if you look at what is being produced and the ability for us to deliver on that shale; I think that the data will show otherwise.
- Just to be clear, it was not the Energy Information Administration that discovered the problem. These were Wall Street analysts who went to the Energy Information Administration and said you are over-estimating shale gas. ***Response: (Campbell)*** I think it is important to understand that some of what dictates prices is the perception of how commodity is available for delivery in time and that is part of

what Energy Information Administration is talking about as revising those procedures for making those estimates. But probably a bigger part of what dictates commodity prices and indicates natural gas and others is what is actually available and that has not been changed based on Energy Information Administration says was produced last month.

- Is there any way we can sense of a possible estimate for the year 2022, how many we might expect in the state? ***Response: (Campbell)*** *I would be more than happy to provide those same principles to Oregon and show you the estimates.*
- Committee had no objections to leaving hydrogen out of the compliance scenarios.
- There is real potential for LNG, especially for long haul trucks. What kind of incentives are available?
- It is reasonable for Oregon to expect that there will be, that some contribution will be made, so in the moderate case I suggest that we add LNG.
- Todd Campbell agreed to pull together estimates of use in Oregon for CNG and LNG.
- I would like to see that curve that was projected collated with the market implementation or adoption of hybrids in Oregon. The adoption rate of hybrids could indicate a likely adoption rate similar for an electric fleet.
- The high estimate ended up at about 5% of the fleet by 2022. How does that compare to what the Northeast states came up with for their high estimates? ***Response: (DEQ)*** *Theirs was actually a total of 8.8%, 4.4% of plug in hybrids and 4.4% of full battery electrics.*
- This projection from George Beard was conservative on electric vehicles. However, they are so low carbon it seems like we should have a case that is optimistic. In addition, I don't know whether the 5.5% is optimistic enough. California used then about 7-8% in some scenarios. They looked at low and high penetration scenarios.
- You wouldn't want to have a compliance scenario that assumed more of a fuel than you think could possibly be produced cause because it wouldn't be a realistic scenario. We are just trying to find how much of these different fuels, low, medium and high cases so that we can put together those different combinations in realistic compliance scenarios. We want to make sure they are all possible. You do not want to assume the high in every single scenario for the same fuel.
- We are looking at California and the Northeast who have not implemented yet and we are saying that their estimates are the best we have. We may have a couple of people that are qualified to talk about this stuff. And we are using that to build estimates. It seems like we ought to get some qualified techs that have some expertise in this area to develop this kind of data. It does not seem like this is a robust process.
- Nobody is going to know for sure how much of these fuels can be delivered, it depends on so many factors that cannot be forecasted. We are going to do an economic analysis on these five different scenarios. One is a high electric future. One is a more natural gas future and one is more of a biofuels future. We are seeing different ways of meeting this rule and then we will do an economic analysis and we will have a hired expert to do that analysis that will tell us what it would cost to deliver this. We just want to hand them five scenarios that are within the range of plausibility. Yes, we are going to be putting together five scenarios and they have a 10% reduction.
- ***CARB:*** *If I may say, I think you have plenty of information to do an analysis of different types of scenarios that you are talking about. I think you are in good shape to put together realistic scenarios that might happen in 2020.*

- I am more comfortable with numbers that we heard today. If we were going to pull from the Northeast or California then bring those numbers in here for comparison. I am more comfortable with going with what we heard today as far as that high estimate.
- I do not disagree with that perspective. It is just that these numbers from today are based on business as usual. We are adopting low carbon fuel standards based on a 10% reduction and that will provide an incentive that does not exist today. If it turns out that electric vehicles are the cheapest way to meet the standard, use of them could increase beyond business as usual. If we are evaluating five different compliance scenarios, we are not determining what is going to happen. We are just saying, what would it cost if it went that way?
- It seems to me that there ought to be one scenario where you push electric as far as you can and see what happens. If 20% of the vehicles manufacturers are going to produce are electric, and that is without us having a low carbon fuel standard, we could predict higher numbers of electric vehicles. Although we do have a low emission vehicle requirement that is driving that as well.
- Car manufacturers move slowly as far as bringing production into line. A new vehicle takes eight years from design to production. Even if with a very sweet incentive, I think the manufacturers are still going to be slow to respond to this. So what is the balance with number of vehicles vs. the incentive? I would like us to to stick with what we have seen and understand. In addition, if we are going to pull something out from the outside in then just show apples to apples.
- One of the five scenarios ought to push the envelope on electric beyond 5% electric vehicles.
- Well I thought the presentation today was sort of pushing the envelope.
- I am concerned about the push on the electric side under a low carbon fuel standard. If you want to have an electric car program, the most efficient way to do it is to have an electric car program.
- Instead of seeing five scenarios with one thing maxed out, I would like to see a scenario with moderate in it.
- I am comfortable with having a scenario that contemplates a more aggressive adoption of electric vehicles, as long as there is also a scenario that contemplates more aggressive adoption of CNG as well. All you are really doing is defining the jaws and then everything in between is what is really going to happen. Somewhere in between your lowest scenario and your highest scenario is where reality is going to hit.
- ***CARB:*** *I would say that the objectives of the scenarios are twofold. The first is to say that the low carbon fuel standard is feasible. The second objective is to estimate cost. It is not to promote one technology vs. the other.*
- That is the main point. We want to show a balance. We want to show what it would cost if we invest in that scenario. We just want to make sure all of those scenarios could possibly be implemented and to see what the contractor would assess the costs. In the end, we are not going to mandate any of those scenarios the market will determine it in the long run.
- The legislature may choose to adopt policies that spur one development and in order to ensure that a mandate is met, but that is not the problem.
- DEQ needs to show the logic behind how you reached the numbers in the five scenarios.

Summary of written comments from advisory committee member or alternate April 16, 2010

- With regard to accounting for the market impact of diverting biomass feedstock and specifically, the Lane County Council of Governments' efforts to find a use for excess agricultural bio-material. One aspect of LCOG's efforts that was not brought up was LCOG's plans for four small scale biomass power projects along the Willamette Valley. If completed and brought on line, those projects would have a demand impact on biomass feedstock in Oregon.

- The rate of EVs by 2020: Based on George Beard's presentation, the outer-most optimistic number of registered EVs on the road by 2020 would be 288,000 out of a projected 4.4 Million registered vehicles. I calculate that to be a 6.5 % EV penetration into the Oregon vehicle market for a high estimate scenario. As I said at the meeting, I'm not comfortable with blindly adopting a Northeast or California rate without first seeing why there is a difference, but even then, have those other rates been proven more right or wrong than Mr. Beard's attempt?
- Under Commercialization Status, the paragraph "Additional infrastructure could be needed to supply electricity for transportation….", the word "could" should be "would" because I don't see how there would be a possibility that you wouldn't need additional infrastructure with more EVs.
- Under Commercialization Status, the paragraph "Electric vehicles have been around for over a hundred years but have not become mainstream due to range and speed limitations." Is there research supporting this conclusion that technology limitations and not other market competition factors allowed gas-powered vehicles to prevail over time? I'd like to better understand this context to give me a better understanding of what prospects over the next ten years EVs have when competing against other types of vehicles in the marketplace.
- Under Commercialization Status, same paragraph, "These new technologies are currently expensive, but with mass production, costs could come down." I understand the expense comes from the use of more rare components so I don't understand how costs would come down in a marketplace of scarcity especially with more demand from EV producers. Also, comments on page 48 regarding Product Barriers appear to contradict the view that "costs could come down" in the next ten years because the progress of battery technology over the last several years has not been analogous to Moore's Law and computer chip development. So, I'm led to conclude that over the next ten years, battery component costs will not likely decrease and battery technology will likely progress slowly. If there is information available to better inform my conclusion, please share that with me.
- Under Commercialization Status, Infrastructure Barriers, the paragraph "Public investment might be necessary to help build sufficient public charging infrastructure due to the low cost of electricity." The present state of charging infrastructure leads me to conclude that we "Public investment will be necessary," and I don't agree that electricity will continue to be "low cost>" Also, the sentence "Fast charging can be expensive to install"—I'm not aware of a fast charging station that is cheap to install. It's at a voltage that necessarily carries safety issues which means more costs for safety, in addition to the cost of the charger itself.

Summary of written comments from advisory committee member or alternate May 29, 2010

- We've never considered IMPROVING gasoline aside from ethanol additives. I know we've talked about other sustainables....various alcohols..but have we REALLY looked into verifying alternative additives or aimed at re-formulating standard gasoline?

July 7, 2010 Advisory Committee Meeting

5. Compliance Scenarios

[Type text]

July 7, 2010 Advisory Committee Meeting

- There is a soft spot in your vehicle miles traveled (VMT) estimates for vehicles between 10,000 and 26,000 Your estimates of vehicles 10,000 or less are good, and a good estimate of vehicles 26,000 lbs and up
- You might want to talk to Carl with EcoNorthwest. He's been analyzing DMV motor vehicle carrier data.
- TriMet announced that they are going to be using CNG, so there should be some additional CNG in the business as usual case. ***Response (TIAX)**: We'll take at TriMet populations and se if we need an adjustment. We will also look at what is in the model for diesel hybrids.*
- Regarding biodiesel requirements: Although I think this is the right approach, I just want to make a point that the reason why we are not shifting to the 10% or 5% statewide is generally there has been a movement away from biodiesel and toward the low carbon fuel standard because of the problems associated with accounting for greenhouse gases or for a number of other factors in addition to some economic impacts. So there is an inherent political trait out that has been made to switch to this, but if we didn't pursue the low carbon fuel standard we would have had a 10% or 5% standard, although this is probably why I approach this for not pursuing the 10% or 5% I think the point should be noted that the low carbon fuel standard is here because we are not doing that.
  - Other committee members disagreed with this statement.
- The concern for me is the E15. For business as usual are we taking a stance that business as usual assumes no regulatory change between now and 2022?
- In the larger perspective, it seems like we are projecting this for no changes in fuel prices and no changes in this. We are projecting it for the one case that is not going to happen.
- Say here is a scenario without a change and then here it is with E15 or here it is with whatever. **Response:** *If you think about how it would affect the analysis if we assume that in the absence of the low carbon fuel standard most likely the legislature would do something else over the next ten years. If we assume those things it would be a baseline that would reduce the estimated cost of this program. And if we go the other direction and assume things are going to be repealed then we are going to overestimate the cost of the program. So it's just a point comparison that we say from business as usual today assuming no further action how would this program stack up. I think in the end when we look at the low carbon fuel standard as compared to the business as usual case, we will still be able to say that in the absence of low carbon fuel standard probably something else would have happened in that business as usual case too and maybe overestimating the impacts of the program. But we still have to compare to some fixed baseline, I think. The traditional map of this business is usual to assume what's on the books today. So we can have some qualitative context for it when we present the final report, but I think we need to compare it against the business as usual.*
- What is of concern to me is where this continuous downturn economy lies in all of the changes. When I look at numbers and I hear these percentages, those of us who have to lobby for the majority of our livelihoods, we know we are going to be in for a difficult session when it comes, because everybody is going to be looking at how the economy has not improved or changed. And when you were talking about the number, the EV project and those things, I think about if people still aren't working they are not going to be buying anything. Folks are holding on, businesses are holding on, letting their fleets. And so as we continue to throw out these scenarios, I hope we don't lose sight of what the economy looks like and ultimately what businesses are looking like. Because all of these things can't happen if people don't have any money to drive that change.

- I know a lot of the things that we make decisions based on are projections, estimates and all that kind of stuff, but here we are building estimates based on estimates. We are analyzing what we absolutely know is not going to be correct. So where I'm having the problem is we know, for example, what fuel consumption was in 2010. We know how much biofuels and all that kind of stuff. Why don't we analyze historical data and then plug in what will happen with low carbon fuel standards and make that the basis for our economic analysis, because we know those numbers. We know that we have to reduce 10% low carbon per gallon and we know how much fuel was burned in any given year and we could then make the economic analysis based on that, instead of projecting to 2022 when we know that we are going to miss the bus for all the reasons that everybody has said.
  - So you want to compare 2022 with a low carbon fuel standard to 2010?
  - You can't compare consumer fuel expenditures in 2022 to consumer expenditures in 2010, so you have to make some kind of projection out to 2022 to make a comparison.
  - I don't understand why we have to make a projection or why we can't just use a base historical year and analyze that based on 10% reduction in carbon per unit on that same historical data. That's what is puzzling me. That to me is the baseline and then you can apply economic forecasts in and say if this happens, if the economy recovers or doesn't recover then you can do it just based on the economic projection, but you've got to solve it based on the projections. We can say we sold 10 gallons of gasoline in 2010 and now we are going to prepare than 9 gallons of gasoline and 1 gallon of something to get a 10% reduction. I know this is more complicated than I am making it, but my point is making it more an actual historical data instead of projecting 12 years in the future and using that as your baseline. Because that guarantees that whatever we say is going to be inaccurate. I guess that's my question.
  - I'm not sure if I quite understand the analysis that we would do. I assume what you are saying is that 2010 could be our horizon year and 2000 would be our start year because that would provide us historic data, because we would know the fuel used in each of those years and then we would implement…or for analysis sake, we would do an analysis of what if we had a low carbon fuel standard starting in 2000. The problem is that we have to use the type of fuel that we are using in 2010 for this analysis and so we can't just pick any random decade.
  - I understand I think where you are coming from, but I think Vijay explained it fairly well at the last meeting. He was talking about how all costs of compliance analysis that will fit in one kind of mold, which is really I think comparing the business without the regulation to the scenario with the regulation. So that is the only way you can get the cost differential and what is the regulation cost.
  - 2010 is in there. That's where we start with the vehicle maxes and that's where we start with the fuels, but you then have to project forward to 2022. Because, just to take the simplest of examples, the RFS2 is going to bring us a lot of biofuel that whether or not we have the low carbon fuel standard and we have to look at the differential cost of the low carbon fuel standard requires over and above that and what else is there. You know gasoline is going to be affected by the changing Café standards, so you can't use 2010 by itself. You start with it and you project forward and say what would this look like in 2022 without this regulation. So I think we are doing what you are staying, starting with the actual 2010 data and then adjusting it for everything that is going to change between now and 2022.
  - I just wanted to say that modeling approach using the baseline 2010 and then developing out the populations with different curves for fuel adoption rates of these different types and the vehicle adoption rates by technology and so forth is the right approach. That is the standard economic

comparative analysis model. And I think having the economic data available for people to review on an annualized basis of the differential between what would be business as usual and the model that we are projecting that gets us on the curve to comply at 2022 is going to be quite sufficient. You see the same type of analysis no matter what type of project you are looking at. If you were going to be building a bridge across I-5, you would be looking at traffic line going to 2022 with and without grids. So you are going to have to forecast what business as usual cases in order to know what type of project you are looking at.

  - I think part of what we are hung up on is this phrase business as usual - is the current context, the current regulatory and statutory construct at the moment that you are setting the baseline, which you assume is going to change. And there are some ways that you can predict that it is going to change and other ways that you can't. You know that it will change, but you are going to say during the next 12 years if that did not change this is what the baseline would look like. And the other thing that I hear Bob saying is why don't you start by, help me if I'm wrong, is starting with just the historical data, but then adjusting that historical data in 2010 to reflect what the fuel mix would be if you had a 10% reduction in 2010 in carbon intensity. So I think that is what you are saying, is use that then as the baseline. So starting with the 10% reduction and then calculating what affect the rule would have. And I'm not sure how you would get there, Bob. I'm having a hard time wrapping my head around the mechanics.

- I always think of it as without regulation as opposed to with regulation.
- I definitely know if that is the case that where Exxon Mobile is going to be having to build out infrastructure and where there are economies of scale and how that matches up to fleets to make sure that a certain portion of our cars are going to be E85 ready, but maybe the economies of scale in California are different. I'm not sure anybody around this table has to be able to make those clear cut decisions. I think that is kind of a decision that needs to be made based on the best experience of the economist and that's that they can provide what generally has happened based on the historic trends, although this has never really happened, but based off the experience or theory of how this may play out or what we should do here.

- You have described for us the boundaries and you've indicated ones pretty conservative and the other is at the other end of the spectrum and my question is, is there a rational way to strike the middle? That you are familiar with and comfortable with and if so it, we'd like to see it. Otherwise, my judgment would be go with the conservative estimate and assign all the costs to the regulation. I mean people ought to know what these things are going to cost. That doesn't mean it's not going to happen, but that infrastructure is going to need to get built out and it's going to need to get built out because of our LCFS. So why wouldn't go with, in the absence of anything in the middle, why wouldn't you go with the conservative estimate.
- When WSPA made their presentation, their point was that RFS2 is going to bring us something comparable to the low carbon fuel standard. So the assumption was all centered in Oregon, but it's going to be out there in the country that we are going get this much ethanol produced if we have an E10 wall, there is going to be E85 infrastructure built somewhere in the country. So assigning all those costs to low carbon fuel standards really over-estimates the cost of that standard. If we didn't adopt the program, it was going to happen anyway somewhere in the country.
- One way we may want to approach this is that we are going to have different analyses and we can look at Washington, we can look at NESCAUSM, we can look at California, and we are going to do our analysis, but if they are all based on different assumptions we can still tie then together and say if you made this assumption these are what you would get and with assumption that is what you would get.

- There are two principle variables and one is that the RFS2 will drive the E85 infrastructure development because the market will have to take up more than the E10's blend wall will provide for. We can't attribute that all to the Oregon low carbon fuel standard. It's not practical and it is not a defensible case in and of itself. In addition, all the data research that has gone on at NREL and Argonne and actual real legacy fleet vehicle testing has proved that the E15 blend stock has got legs under it, politically potentially, and if not, at least, at E12. So we have to keep in mind that it is highly likely that standard will change during this term of our LCFS build out and we ought to at least address it. And if it is at the mid ground, is it? That's a good question, but I don't think we can attribute all ethanol above an E10 blend wall causing additional infrastructure costs to be LCFS dependent.
- That's why we're thinking that we should stay with the E10 blend wall. That's the current regulation. Washington is looking to do 15. So that will be good that we will get to see it both ways. Because, if we stick with E10 then the questions is whether we are going to get less than our proportionate share of ethanol in the base case or whether we are going to assume that there is going to be E85 infrastructure built to absorb our full proportionate share. And I guess the question I would ask is if Oregon's got the same proportion of flex fuel vehicles in our fleet out there as other states do, what would be the economic driver for the fuel distribution that oil industries provide less than the E85. That would be the questions. Is there some reason people can think of why Oregon would get less E85 infrastructure than other states would get if we have roughly the same proportion of flexibility? If we can't think of a reason, then we should just assume that we are going to get our share of E85 infrastructure.
- Doesn't Oregon have a historical evidence of early adoption of other fuels, so I think if anything I would say we would at least have our proportionate share of E85 vehicles here or more.
- I have no reason, based off my experience and knowledge, to think that we would have a different proportion of ethanol and biomass-based diesel than any other state. One factor is what the scale is for building infrastructure in other states to be able to meet the E85. And I think that question is a smaller, would probably have a small impact on what our proportion would be. And so, I would lean towards something closer or really close to where the proportionate share was. We may want to discount it by some factor. So if we do like a 5% reduction to proportion shares or something like that. We have to come up with something that makes the most sense, that represents what a regulatory environment would be if we don't have low carbon fuel standard. And it's likely closer to the proportionate share, but I don't have expertise to know exactly what that number is.
- Perhaps states that have higher volume gas stations might have a greater ability to put in a second tank.
- Yeah, I don't think we will hit our proportionate share, just based on ability to permit and do things, because the facilities that we have now much less expand, based on population size. I'm not saying that we won't get some of it, but I think there are a lot of other places where you could make heavy infrastructure investments and serve a far larger population for that capital.
- Another piece of data that would us decide is might be to look at the distribution for our gasoline stations, how many gallons they sell relative to say New York and see if we are average or below average or above average. And maybe use that somehow to factor us off of proportional case or something like that.
- I don't know if you have talked to any of the terminal folks? What kind of constraints are there in those terminals that serve basically the entire state.
- Probably every other state has similar problems, so we have to do a relative comparison. If you have this much volume to move, it's got to go somewhere and if we are significantly different, because let's say we are an average of so many gallons per month, then in the bigger state the typical gas station sells twice as many gallons. One they can probably afford to put a tank in, where we can't.

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- With regard to ethanol staying in the Midwest; they already have a high proportion of E85 use. And then the question is, is what is their fleet capacity to take more E85. So, there are so many factors here. I think the approach of looking at gasoline station throughput is a good one.
- Assuming that other states are in the same boat there would be more blending facilities. There is no reason to think that biofuel and ethanol use wouldn't proportional here.
    - I don't think we are in the same situation, because states are unique.
    - Most states have refineries and this isn't a concern.
- We should find out what capacity the blending facilities are and factor that into the analysis.
- Before we go there, I'm unclear about where we left the discussion around ethanol. I would like to have seen maybe an option or two developed that our technical experts felt are defensible that we could then ask questions about and challenge and arrive at. But, to be just kind of given the option of two bounds, neither of which is acceptable, what do you think works? I'm ill-equipped to respond to that question. ***Response (DEQ):*** *Here is where we left it on the ethanol, we said it's going to be somewhere in between the two and we are going to look at the through-put average for a gasoline station in Oregon and compare that to the national average through-put and come up with some kind of a factor that would be applied to that difference. And that's sort of a technically justified cut, I think.*
- For CNG light-duty vehicle projections, NGV Association might have numbers or studies. California is pursuing CNG. ***Response****: When we talked about fuels assessment, we decided to use Energy Information Administration projections on the light duty CNG. That's why you don't see a higher light duty CNG, because of that conversation that the committee had.*
- If we could find defensible, rational numbers around light duty CNG projections, I would encourage that. Clearly, I'm dubious that those numbers exist with any depth, or that any robust numbers exist in that regard.
- On heavy duty LNG – why is heavy duty LNG not considered? In California, we are seeing the natural gas favor the LNG engine compared to the CNG.

Summary of written comments from advisory committee member or alternate July 21, 2010 regarding draft compliance scenarios presented July 7, 2010.

- The economic impact of scenario assumptions will drive scenario viability both within a scenario (for example the economics will drive the split between cellulosic ethanol and other low CI ethanol) and across scenarios (the Cellulosic (Scenario 1) and stated Max EV and Cellulosic (Scenario 4)). Will DEQ carry out a "loop back" to revise scenarios due to economic impacts as part of this review?
- Oregon Distillate Use data contains Farming and On-Highway. We understand that farming and logging trucks (part of the on-highway fleet) will be exempt from the Oregon LCFS. Will these volumes be removed?
- What is the 1000 EV project and who is paying for it? Is the funding for this project secure given the current economic climate? Is the increase in EVs as a result of this program reasonable, what cost assumptions are used? The EV:PHEV ratio is increased from 1:99 to 1:6, this seems to be a large ratio increase. How realistic is this? Upon what assumptions is it based? We note there is an assumption made that HEV, EV and PHEV sales in Oregon will be twice the national average. We question where this assumption came from and how realistic this is.
- VMT – Will this be adjusted for pass-through trucks?

- Light Duty VMT is noted as being adjusted by a factor of 1.23, essentially a force fit. As the fleet changes through the modeling period of 2022 and fuel economy changes are overlaid, will the adjustment skew the analysis?
- Medium and Heavy Duty is noted as in a state of flux. Will farming and logging trucks be removed from the analysis?
- The BAU case considers the EPA Analysis Primary Control Case as the basis for volumes on slide 17 and 18; however given the EPA's recent need to modify cellulosic biofuel requirements, does this represent a reasonable basis? The technical, market and economic viability of the listed renewable fuel categories are not equivalent, and adoption curves for these materials will vary. The relative volume estimate of Brazilian ethanol seems very low given that it is a fuel which is readily available today. Similarly, the cellulosic portion seems high given the technical and economic hurdles of seeing this category in the marketplace within the analysis timeframe.
- As discussed with respect to slide 17/18, the Imported Ethanol adoption curve appears to be very low in the early scenario years despite its current availability and its proportional volume is viewed as unrealistically low. By contrast, the combined cellulosic ethanol and cellulosic diesel seem overestimated compared to imported ethanol. Were credible estimates of technology availability used to create these adoption curves and who provided these estimates?
- As the EPA has yet to issue a waiver for E15 and has indicated that it may only grant a partial waiver for E15 in light of the fact that older vehicles and most existing non-highway engines are not compatible with E15, it is viewed as not reasonable to use an E15 assumption for the BAU case nor to define any FFV E85 assumptions. The FFV E85% of 35% VMT appears unrealistic and should be tested against current Oregon State E85 supply in order to level set any FFV projected estimates. It should also be noted that while FFVs are currently produced, this continued production is not required by any regulation, and it is not clear that a large and growing FFV fleet will be part of the Oregon vehicle population in the years modeled.
- In addition, we question whether there is a mathematical or assumption error regarding the FFV/fueling %.
- The E85 infrastructure investment should not be part of the BAU case as the FFV E85 VMT assumption is viewed as overstated.
- EV and PHEV EER Assumptions - The use of EER assumptions as used by CARB in their LCFS analysis as a starting point for this Oregon analysis is a significant concern. CARB staff did not make any adjustments to the fuel economy estimates of EVs or conventional vehicles to reflect the impact of actual (as opposed to laboratory) operation. A recent study by Argonne National Laboratory (see http://www.transportation.anl.gov/pdfs/TA/629.PDF) has found that real-world EV operating conditions have an important influence on well-to-wheels GHG comparisons relative to conventional gasoline vehicles. Another important factor is ensuring that the EV is being compared to a gasoline vehicle of equivalent performance. As data become available on real-world energy use by EVs and PHEVs, it is imperative that the EER value for EVs be re-evaluated.
- Light Duty Diesel – Oregon is proposing to separate diesel LCFS compliance from gasoline compliance. We believe that a combined pool of diesel and gasoline gives a more technically accurate GHG reduction opportunity for Oregon. The GHG benefits of a light duty fleet change from gasoline to diesel will be neglected in the proposed separation of gasoline and diesel compliance. In addition, it will not support the technical opportunity for Original Equipment Manufacturers to market advanced clean diesel technology in the North American market, nor give incentive for fuel providers to increase the retail presence of diesel fuel to facilitate this market shift.

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- We would like to see the overarching crude oil price assumptions and intended sensitivities to be used for the analysis.
- The Proposed Compliance Scenarios are separate gasoline and diesel pools. In keeping with the GHG of LDD replacement of the gasoline fleet, we feel a one-pool scenario is needed. It was noted at the July 7th meeting that Washington State is proposing a one-pool approach, and we encourage Oregon to adopt this approach as well.
- The listed scenarios do not appear to have a basis in their overall technical or economic likelihood. We believe that realistic scenario boundaries are important so that the JFA economic analysis is not created with "boundaries" which are not balanced by market and economic possibilities. As such, the scenarios need to be built from the bottom up using credible estimates of technology availability, and recognizing competing demands for available resources.
- Draft Scenario 1 – Brazilian ethanol is viewed in the presentation as unrealistic within the 2022 timeframe. In fact, Brazilian ethanol represents currently available product that will deliver a significant CI benefit when compared with the other conventional ethanol types listed in this scenario. As cellulosic ethanol is technically and economically unproven in the market, the use of this material to balance the scenario seems tenuous. What is the production capability assumption of cellulosic ethanol for this scenario based on? Are credible estimates of technology availability used to derive these?
- Draft Scenario 1 also lists E85 use in order to balance the scenario, yet we question the basis for this, given the need to increase E85 infrastructure and assume E85 fleet continuance (or expansion).
- Draft Scenario 2 – Why is 189 MGY of cellulosic ethanol viewed as moderate? On what assumptions is this based? What is viewed as high E85 VMT? In what year? What fleet assumptions from OEMs are used to estimate these?
- Draft Scenario 3 – We do not see the relevance of a no-ILUC scenario.
- Draft On what basis does Scenario 4 define an EV population of 240,000 and PHEV of 288,000 by 2022? Why are these two populations so close when the anticipated cost of EV home-based recharging stations is so high – what economic analysis has been done to ensure that this scenario has a likelihood of being adopted? We believe it would be preferable to derive a more market based estimate of a high EV world with assumptions based on vehicle manufacturer market estimates or similar information.
- All draft scenarios – What assumptions are used in the allocation of the balance of the scenario to Pipeline NG into CNG? This would require considerable flexibility in any assumptions on the CNG fleet. What would they be based on? How does this fit with the balance that also goes to Midwest Soybeans? We would expect that a single balance of the scenario would be preferable and should be allocated to a biodiesel category.
- Why is all Northwest Renewable Diesel expected to be used by the aviation industry? How does this factor into the Oregon LCFS and the diesel and gasoline pools? It is not part of the BAU baseline.
- Draft Scenario 5 – On what basis is the Oregon Cellulosic Medium level of 110 MGY based? On what basis is biogas for CNG estimated as half of unused as Moderate? We anticipate that market and infrastructure cost will determine whether Biogas is directed to transportation or electricity generation.
- Draft Scenario 6 – How is "up to maximum available" determined for Northwest Canola?
- Draft Scenario 7 – Why is 1.5 x BAU in view for the Maximum Natural Gas scenario? Does this align with vehicle manufacturers' estimates? What are other drivers for this HD fleet change?
- Draft No HD PHEV's are factored into the scenarios. Could this be included in Scenario 7 as a maximized alternative scenario?

[Type text]

August 10, 2010 Advisory Committee Meeting

- Couldn't find a way to track logging trucks for their exemption. It's not really an issue. Number one, it's small. Number two, they're going to be using the same fuel as everybody else, because we're not going to have special gas stations for log trucks.
- There's a lot of policy discussion at the Federal level about promoting, especially heavy-duty, LNG vehicles, and that's actually very relevant in Oregon, because a lot of talk about establishing an I-5 corridor from Canada to Mexico based on LNG. *Response (JP): LNG populations are pretty low, the carbon intensities for LNG are pretty similar to CNG, and since we're increasing in all the scenarios the CNG population by 20%, we've decided that's a combination of CNG and LNG.*
- Separate out heavy fixed construction because we're already accounting for it in the off-road vehicles, through Energy Information Administration data. There are no special exemptions for construction equipment.
- Do we see a natural shift from gasoline to diesel going on between 2010 and 2022? *Response (JP): Gasoline has declined in 2010 – not a lot, but it has declined at the expense of hybrids. And then diesel, it grows a little bit, but not really much at all.*
- Based on comments from the last meeting, we looked at the gas station throughputs in Oregon, and compared it to the U.S. average throughput. It's quite a bit higher – 524 gallons per day, vs. 489 for the U.S. average. This justifies that comparatively speaking, the gas stations in Oregon have the economic ability to absorb the E85 infrastructure costs.
- I thought I saw something about the EPA now looking at E12 instead of E15 as an interim measure; do you know anything about that? *Response (JP): Need to track down that information. The problem with the E15 is that the vehicles from the years 2001 and older can't handle it. So perhaps the 2020 frame would be appropriate, because those vehicles will be retired.*
- Does that matter economically? However you get there with the RFS2 compliance? *Response (JP): Economically, if we have investment in E85 infrastructure in our business as usual case, then it's no increase for the low carbon fuel standard. So if there's no investment in E85 in the business as usual, then the low carbon fuel standard is more expensive,*
- Because the question of blend wall isn't settled, we're not putting in the BAU. But we are having to look at it as part of the various compliance scenarios. And we need to do it in 2016 when we look at reviewing the program.
- I think you have to take into account the fact that there is no state barrier to ethanol production, and people will necessarily build wherever they can get the best transportation, best labor costs, best operating costs, and it's a very real possibility that you could have a lot of ethanol production in Washington or Idaho or some other place, with minimal transportation costs if it's just across the border. I'd almost do three of them: One where nothing is produced in the state of Oregon, everything is produced in the state of Oregon, and a split.
- The folks who are doing runs of the model, REMI Northwest, will only crank the model as many times as we tell them to. There's a cost involved in going through that process. We can do certain things with them that don't require a full set-up of the model, where the model is going to be run one way, and then we only have to change one variable. They might not charge us a full ring of the register for that, but that has to be negotiated with them.
- Are the CAFÉ standards incorporated? *Response (JP): They are.*

- What is the incentive that we're assuming we're going to get people who have flex fuel vehicles to use it? *Response (JP): The onus is on the fuel providers and the low carbon fuel standard to sell the required volumes of fuel to meet fuel standards.*
- If we do the E15, the VMT shares would have to be? *Response (Jeff): It cuts it in half. It goes to 30% FFV miles, as opposed to 60 with an E15 blend wall in 2022.*
- In Europe, the way they're reducing the carbon intensity is by shifting to diesel. I thought the idea of this one pool scenario was that you would have more light duty diesel vehicles, and increase the actual shifting from gasoline to diesel, and then see how that affects the overall scenario. *Response (JP): How would we estimate how much that shift would be? How about a 10% market share in 2022? It's just 6% in autos, so overall fleetwise, that's not a huge jump going to 10%. What if we just do a 15% increase each year on sales, for light duty autos and light duty trucks?*
- For the first time in the UK, in Britain, light duty diesel surpassed sales of light duty gasoline.
- What is DEQ's position on the NOx bump? CARB is convinced that biodiesel increases NOx even at the 5% level. I wondered if you agreed with that. It even plays into ethanol since even if it is not an ozone issue, the NOx might be. *Response: We don't have a position on it, but it is an issue. We haven't done that analysis.*
- There's also different refining configurations in Europe that are meant to produce larger quantities of diesel vs. gasoline. *Response (attendee): Some refineries can change configuration and others can't and the degree of complexity of the change will be different.*
- If you're looking at California having their (LCFS) program in place, are we going to see a lot of this (lower CI fuels) going to California that then won't be available to Oregon?
- Can we resolve the ethanol blend level question? *Response (JP): Use it in the mixed ethanol with and without indirect land use change.*

Summary of written comments from advisory committee member or alternate August 16, 2010

- The Level 2 residential charging station cost looks low. I think Coulomb, ECOtality, GE and others are in the $2,500 to $5,000 range for materials (a charging station) alone.

Table 3. Plug-in Vehicle Home Charger Installed Costs.

Level 2	
Labor	$962
Materials	$1,195
Permit	$14
Total	$2,088

- Perhaps check pricing (all levels, public, private) with Coulomb and ECOtality. They're both involved with the EV Roadmap project here in the Northwest so their pricing schemes would be directly relevant for modeling.

6. Economic Analysis

[Type text]

December 3, 2009 Advisory Committee Meeting

- How many sensitivity runs does DEQ plan to do when compiling compliance scenarios? From utility experience with integrated resource planning, it's easier to try to put brackets around upper and lower bounds for most optimistic and most pessimistic scenarios, as opposed to specifying a single number. ***Response****: We plan to generate ranges, not specific values.*
- California looked at a range of possibilities, including mixes of low and medium carbon intensity ethanols.
- The upcoming change in fuel economy as required under federal GHG regulations will affect the cost of complying with the LCFS. Will this be reflected in the GREET model or in the economic analysis? Also, federal fuel economy regulations will affect EERs which compare the energy efficiency of alternative vehicles to comparable petroleum fuel vehicles. ***Response****: Oregon has already adopted low emission vehicle standards, which will be reflected in the baseline for the economic analysis. Mr. Satyal noted the point (about accounting for federal fuel economy regulations) and will ensure the baseline for the economic analysis reflects applicable standards.*
- Oregon is required under HB 2186 to take into account changes in drive train efficiencies, which may be different than California's requirements. If we are partly achieving the GHG reduction goals of the LCFS by reducing the volume of fuels consumed due to power train efficiency improvements, then this must be considered in the economic analysis. ***Response****: The economic analysis will reflect Oregon regulatory requirements. The purpose of this presentation is to get input on writing a request for proposals in order to hire a contractor to perform the economic analysis. DEQ will add references to drive train efficiencies and federal fuel economy regulations into the RFP. Drive train efficiency was mentioned in the bill to ensure that the carbon intensities calculated under LCFS program take into account differences between the relative efficiencies of electric,hydrogen and natural gas vehicles. The intention was not that Oregon would comply with the LCFS by changing vehicles. DEQ and commenter agree to pursue discussion about the significance of the statutory language on drive train efficiencies outside the meeting.*
- Impression was that LCFS aims to get a reduction of 10 percent below forecasted "business as usual," not 10 percent below whatever carbon intensity was when the legislation was passed. Is this correct? ***Response:*** *No.*
- Railroads plan to make major changes to their engines over the next several years, which will result in 15 percent reductions in emissions without using biodiesel. They want to make sure these improvements are taken into account.
- Will our state program cause any problems with NAFTA, which will result in more Canadian trucks on our roads?
- There is a need to understand the contributions of other climate change programs already adopted in order to understand the economic impacts of a LCFS program.
- What consumers and businesses care about are changes in fuel prices, not changes in the costs to produce fuels. It's difficult to forecast how changes in cost will translate into changes in fuel prices - how will the analysis deal with fuel prices? ***Response****: CARB found a small reduction in costs, but allowed that all or none of the reduction in costs could be passed on to consumers.* ***Response*** *(CARB): In their economic analysis, CARB avoided looking at changes in prices because prices are affected by all kinds of additional factors, not just changes in production costs.* ***Response*** *(Mr. Satyal): Oregon is much smaller than California, and hence is a price-taker in the fuel market. Taking this into account, together with price-driven changes in driving behavior and innovation by industries, the factors can essentially cancel each other out with respect to impact on prices. The RFP will include consideration of how changes in*

costs will affect fuel prices. If time and resources allow, the contractor could perform sensitivity analyses that would look at price effects.

- Isn't local supply of alternative fuels a function of prices? ***Response*** *(Mr. Satyal): Yes, and the economic analysis will take this into account.*
- Economic analysis needs to account for benefits, not just costs, such as avoidance of CO_2 cost risk under future national or international programs which would impose costs on GHG emissions and public health impacts of reductions in air toxics from changing fuels.
- Will analysis include costs to railroad companies of fuel additives necessitated by use of biodiesel? Even if the fuel is the same price, biofuels may bring additional expenses. ***Response*** *(Mr. Satyal): Yes, additional costs should be taken into account. He would encourage fuel users to bring this kind of information forward for inclusion in the analysis.*
- Public benefits, including environmental improvements, should be taken into account. ***Response*** *(Mr. Satyal): REMI as a tool is somewhat limited in this respect, but can incorporate information on related economic impacts. The literature review which will accompany the economic analysis can look at factors which are not easily quantified.*
- Will the contractor be getting information solely from the advisory committee? ***Response*** *(Mr. Satyal): The contractor will look at existing published information sources, as well as analyses already performed by other states.*
- Will the economic analysis be able to account for supply shortages of biofuels to meet the LCFS, which will influence prices? ***Response****: The compliance scenarios will be based upon reasonable projections of how much low carbon fuel will be available. The economic analysis will be based upon the compliance scenarios, so it is important to come up with reasonable scenarios. Also, the statute requires DEQ to build deferrals into the regulations in case expected sources of low carbon fuels do not materialize.*
- The analysis of federal diesel rules attempted to look at externalized costs and benefits (such as health effects), and could be a good starting point for DEQ's analysis of the LCFS.
- Request that DEQ and Mr. Satyal put together a list or matrix of key REMI assumptions that will affect the economic analysis results, perhaps soliciting input on what values to consider for business-as-usual, best case, and worst case. ***Response****: We plan to talk about the assumptions in February.*
- Process assumes there will be credits that will be bought and sold by fuel producers. Will cost of credits and the trading mechanism be included in the analysis? Don't we need to know the design of the trading system before we estimate the compliance costs of the program? ***Response****: The ability to trade lowers the cost of compliance, so leaving credit trading out of the analysis provides a conservative look at costs. On the other hand, transaction costs would not be accounted for.* ***Response*** *(CARB): This is a cost analysis. Since the costs of a trading mechanism depend on the design and are not yet known, CARB left the cost of credits out of their analysis.*
- California is spending $ 250 million per year over the next seven years in incentives to help meet the LCFS. Oregon also has incentives, such as the BETC (Business Energy Tax Credit) that will help toward meeting the LCFS. These incentives show up in the accompanying handout (page 10) as cost savings under the LCFS, but they should in fact be considered as costs of meeting the LCFS. ***Response****: The analysis will identify costs to different sectors, such as business and government. Savings to one sector may be a cost to another.*
- Calculating the costs of tax credits must take into account long-term public benefits, as well as short-term costs. Analysis of this kind has been done in Oregon on the BETC.

- How much money has DEQ allocated for this analysis, and is it a reasonable amount for a quality product? ***Response****: The budget is something over $100,000. Oregon and Washington have received a grant from EPA to cover the economic analysis in Oregon and some related analysis in Washington.* ***Response*** *(CARB): CARB has already done much analysis which will be similar for Oregon, and can share their results for use and modification by Oregon's contractor.* ***Response*** *(Mr. Satyal): Oregon's RFP includes a literature review that will identify analyses and data from other states that will be useful.*
- As far as credit trading, it would be wise to consider different assumptions. The worst case is an illiquid market with few credits to trade, e.g. few electric cars entering the market. If there are no credits to trade, then trading will not help ease compliance costs.
- There are historical data and many studies on costs of credits and transaction costs, providing a range of outcomes. ***Response*** *(Mr. Satyal): EPA has analyzed credit trading, and several studies are available from the National Center for Environmental Economics.*
- How will sectors be chosen for the analysis? ***Response*** *(Mr. Satyal): The contractor will choose a list of sectors to be included, and then run the list by the advisory committee.*
- California exempted certain fuels that are subject to interstate and international commerce, while Oregon's statute calls for fuels used by agricultural vehicles and logging trucks to be exempt. At which stage in the economic analysis will exemptions be accounted for? ***Response*** *(Mr. Satyal): Probably in the fuels assessment or compliance scenarios, but the contractor may suggest another way to account for it.*
- Even though current statute allows certain users to be exempt from the renewable fuel standard (RFS), they are not always able to buy clear gas, so there are other factors at work.
- Observation that the consensus of the group seems to be that the overall structure makes sense, although committee members may differ on what should go into each step.

Summary of written comments from advisory committee member or alternate December 16, 2009 regarding Proposed Economic Analysis.

- What will be considered business as usual? The current economy is not exactly "business as usual" with fuel prices depressed due to the poor economic conditions. What is a good comparison to make? Should several "business as usual" scenarios be run?
- Can the analysis be done on a regional basis in Oregon so we can see if there are disparate impacts to the Portland metro area compared to eastern Oregon, southern Oregon etc.?
- DEQ is proposing to focus on the direct fiscal impacts to parties directly affected by a LCFS and on a set of questions developed by DEQ and the committee. I agree that this should be the focus but I would suggest that the indirect socio-economic impacts be mentioned in a qualitative review.

January 27, 2010 Advisory Committee Meeting

- Economic analysis should include changes to gas tax revenues due to the increase in numbers of electric vehicles.

April 15, 2010 Advisory Committee Meeting

- Are we going to do an economic analysis on biomass availability to show us what is possible, or are we just going to do a technical analysis? It seems to me that an economic analysis would be very helpful, for example for grass seed straw. There is a lot exported to Japan and other places for animal feed, bedding, etcetera, so we would be competing with that economically. ***Response: (DEQ)*** *We need to look at that. I* *know in California's economic analysis, they did look at the cost of feedstock and that certainly is something we will look at.*

June 23, 2010 Advisory Committee Meeting

- We do not have the economic models available to include new and emerging sectors in the economic analysis. For example, electric vehicle recharging stations don't exist here yet – how will things like that be included? There are other sectors as well. It seems like the system looks more at costs for existing sectors than benefits to new and emerging sectors. ***Response (ODOE):*** *We take things as they are but also look at what we want things to be. It will take at least three to five years and that is a guess because public infrastructure has to be designed. The question will come about public aspiring ventures. If it needs to be prepared as an option of low carbon fuel, what is the source, what the base operating sector that it comes from? If the state agrees strongly then maybe an appropriate subset could be put in that account for change and production of fuel that accounts for the sector. So that is feasible. What assumption will have to be made and how you wish to designate it in the model. There are some other sectors that represent emerging pathways. And that would be important to really bring out and bring up…ask the contractor, what sectors you wish to feel there are some emerging economy created that are not looked at in the sector you have given and please highlight and give ideas or comments back to Sue.* ***Response (DEQ):*** *When we sit down with our contractor we want to talk about the sectors to be evaluated. Posted online and provided to you is the list of the 70 sectors that are typical for REMI. We would like to get your ideas as quickly as we can so we can talk to our contractor about are there specific sectors for Oregon that you think we really need to include, whether it's current sectors that just you said are not on the list or emerging sectors. And then are there any questions that you think the analysis should really be designed to answer.*
- On the economic analysis, is this where you would consider whether or not certain folks are just not going to supply fuel to the state in certain sectors? We don't dictate to anybody because we don't have enough of a market. So basically, one potential scenario is that some companies say it's not worth it, because it's only a limited market that's requiring this. I'm just going to move out of there. We see it all the time with different brands changing, like fuel stations. It is not easy to do in a California scenario because it's a big market and nobody wants to be out of there. But it is very easy to do in Oregon and that drives the cost up. Is this where you want that information or that kind of questions to be asked? What happens if XYZ Oil Company decides not to sell in the state? ***Response (ODOE):*** *However, what you are saying behind the question is that as the price taker we would model or we would assume in the business of using some conditions or reality or fuel comes in from there and we really want the whole distribution or who is more readily more effective and who is not. What this assessment will simply do is provide a snapshot of who is impacted by how many and what costs they will incur and they will benefit from if they want to explore any of these compliance scenarios over time. So what you are asking for is an exit analysis that is not typically done in this kind of work.*
- We talked about what would happen if, despite our compliance schedule, the supply doesn't materialize on the dates that we need it? We are building into this program the idea of having deferral so if we get to a given year and there isn't fuel available either because a plant wasn't built on time or perhaps a supplier decided not to sell to Oregon for whatever reason the mechanism we would use to respond to that in real time in the future would be defer the phase down by a year and to provide more time for the market to adjust. Can the model look at what happens with the deferrals? ***Response (ODOE):*** *There is a way to address that timeline. What time you expect sudden substantive fuels to come online and be available and that would be a way to address some of those issues. That is where I expect the low carbon fuel*

supportive technology available resource providers to really give a fair assessment of how long they think their resources will come online. And that can be assessed here.

- Fuel price concerns everybody. I understand that you are going to get results at the level of government, general public, by sector, etc. How much further down are you going to be able to go? Take construction. Will the economic analysis include the kind of equipment issues, modifications, and the costs for changing a largely legacy fleet? Is technology available? At what cost? How far into all that will your sectored analysis go?
- Remember, we are not talking about a biofuel standard here. It is a low carbon fuel standard and the amount of biofuels that can be blended are limited by federal law, although EPA is looking at changing those percentages. The compliance scenarios are going to have to take into account the amount of blending of biofuels that can happen and also look at the other types of low carbon fuels. For example, electric vehicles and natural gas vehicles and so forth that wouldn't necessary affect your equipment because you would be using different sectors. And the compliance is at the level of the oil company where they are doing a calculation at the end of the year to show that their credits and deficits add up. So it doesn't automatically, like a biofuel standard, result in your sector getting more biofuels than you can handle with your legacy equipment. Low carbon fuel standard doesn't necessarily result in that.
- If you look at how deep those fuel prices are, then you have a different class of business Oregon economy or sector. There are very basic, few key variables that, in fact, use the low carbon fuel standard as an option. And you are looking at the main fuel price that impacts the economy. And at the pump current prices, those kinds of effects will be looked at. So you have indirect to the economy. And that would not be easily captured. Not because of the main fuel price can affect any particular sector in town so the cost of production and cost of distribution would be assessed. That would impact even the state.
- We are a price taker right now, but one of the co-benefits of the low carbon fuel standard is to become a price maker by producing more of a fuel locally, either through biofuels or through electricity. And then also one of the key things that is not in this model and I don't expect it will be, but I do hope that we'll talk about it and provide some data, maybe outside of this on some other research that has been done so that way we have some contexts around the environmental social benefits of the program. For example, if we are able to reduce some of the air toxics associated with fuels then we will also be having health benefits in reducing healthcare costs. So that is something that conceivably should be in the model, because out of all the externalities that are able to be captured that is probably the easier data points, lots easier around climate change and things like that. But to the extent that we can, at least, capture that benefit as a descriptor outside of the model would be very helpful. ***Response (ODOE):*** *They want quantitative variables. Some of this is a direct impact that we can measure or capture. We have to look at literature and quantitative assessment and bring that into the analysis in terms of the report. It is not doable in REMI.*
- A couple of people have made the point that we need to make sure that we capture the economic benefits of the program as well as the costs, and a key factor really is, what is going to be the future price of crude oil versus what is going to be the price of delivering low carbon fuels. That's the guts of the analysis and I think that is what REMI is going to do. When you are looking at the 70 sectors and then the other sectors that are not highlighted, if you see ones that we need to highlight, let us know. We'll make sure that we capture those, but the basic piece of the analysis is really the business as usual case forecasting, what is going to be the price of petroleum fuels, and how much is it going to cost to produce these low carbon fuels. The analysis is going to be probably quite sensitive to the forecast of future price of petroleum. The other question I wanted to ask you is on sensitivity analysis it seems like one of the key factors is going to be looking at the price of crude and are we going to be able to have some sensitivity on that? Like if crude is $100 per barrel, this is how low carbon fuel standard is. Or if it is $50 a barrel,

here is how it is. From what I understand a lot of the benefit is diversifying the fuel supply and having some stability of alternate fuels relative to just the crude oil scenario. ***Response (ODOE):*** *Yes, a typical crude oil forecast will have at least, two to three price breaks scenarios. Finance deals stop working if crude oil prices go below a certain price. So there will be some threshold variables that will be accounted for. We may not have 20 sets of crude oil prices, so there is a range or degree of perfection that need to be forecasted. But there will be some break apparent low, medium, and high case for crude oil price forecasting that will be viewed to, in effect, different economy conditions.*

Summary of written comments from advisory committee member or alternate June 17, 2010

- Staff should be commended on selection of Jack Faucet and Associates as the economic modeling contractor. They are a well-known, national entity with very well thought of credential and reputation for this specific type of work. In addition, directing the the use of the REMI model will clearly address the interactive dynamics, nuances and market complexity well. The breadth of modeling 70 markets is likewise well advised.
- There are numerous externality benefits we would like to see modeled and valued in the economic analysis such as air quality, community health, potential rotation cropping benefits, etc. etc. At this juncture, they are not addressed by the model scope. Should there be opportunity for the contractor to address some of those additional outcomes it would be refreshing, useful and likely more compelling an economic model for a broader Oregon constituency.

Summary of written comments from advisory committee member or alternate June 25, 2010 regarding the proposed economic analysis

- The timeframe for the economic analysis should capture all of the costs and benefits. For example a car purchased in 2015 will continue to have fuel savings impacts beyond the horizon year of the program.
- The economic analysis should consider beneficial impacts on regional economic activity and employment. The commenter cites comments on NESCAUM's economic analysis "Specifically, the analysis should delineate the following impacts:
  - Percent of GSP increase (decrease) resulting from growth (decline) in regional fuel
  - production;
  - Percent of GSP increase (decrease) resulting from lower (higher) fuel prices;
  - Percent of employment increase (decrease) resulting from growth (decline) in regional fuel production and/or the manufacture of vehicles and component parts needed to use low-carbon fuels; and,
  - Percent of employment increase (decrease) resulting from fuel savings (added costs) spent in the wider economy." (from Joint environmental stakeholder comments regarding draft preliminary assumptions for economic analysis, low carbon fuel standard for the northeast and mid-Atlantic states, May 7, 2010. http://www.nescaum.org/documents/stakeholder-comments-on-the-economic-analysis-of-the-northeast-mid-atlantic-low-carbon-fuel-standard-draft-data-and-assumptions-part-i/comments-from-ceres-citizens-for-pennsylvania-s-future-conservation-law-foundation-ene-environment-america-environmental-entreprenuers-natural-resources-defense-council-union-of-concerned-scientists-and-vermont-public-interest-research-group/environmental-stakeholder-comments_05-07-2010.pdf/view)

- Consider the impact on Oregon Greenhouse Gas 2020 Goal - it is important that the value of the CO2 reductions of the LCFS in contributing to Oregon's strategy to meet the 2020 goal be recognized - ie. the cost to meet the goal will be higher if this fuel component is not achieved.
- Review the State of Wisconsin LCFS macroeconomic analysis, which models a non-LCFS biofuels policy that impacts the agriculture and forestry sector positively to see if it suggests ways to capture the homegrown jobs of the LCFS substitution factor in OR. (http://www.climatestrategies.us/ewebeditpro/items/O25F22680.pdf)
- Account for existing complimentary carbon reduction strategies. The United States and the State of Oregon have several existing strategies that will lessen the burden to meet a 10 percent reduction in greenhouse gas emissions intensity by 2020. For example, renewable fuel standards already incent the development of biofuels. The national and state tailpipe emissions standards will also decrease the hurdle of developing low-emission vehicles, which, although these "Clean Cars" standards will not change the carbon intensity of existing gasoline and diesel fuels, could affect the relative cost accounting for fully electric vehicles. Additionally, for more than 30 years the State of Oregon has incented renewable energy and conservation technologies that can help catalyze the development of alternative fuels.
- Recognize the cost of replacement policies to achieve state greenhouse gas reduction goals. In 2007, the Oregon legislature adopted goals to reduce greenhouse gas emissions 10% below 1990 levels by 2020 and 75% below 1990 levels by 2050. One of the key strategies adopted by the 2009 legislature to achieve the 2020 goal was the LCFS. Failure to fully adopt the LCFS will require the adoption of additional climate policies to make up the carbon gap. In addition, failure to meet the 2020 standards will require even deeper cuts later than currently targeted by the state. These necessary additional policies will have a significant cost. Although the purview of this economic study is ostensibly to just account for the gross state product impact and not the externalized costs and benefits of an LCFS to society, it is essential that these impacts be reflected through at least a detailed and thorough literature review. In particular, the following should be considered:
- Account for emerging technology and business benefits. Within the economic study, it is important that several factors be considered:
    - New businesses and jobs – both direct and indirect – as a result of the development, production, manufacture, distribution, and infrastructure enhancement for new alternative fuels and complementary vehicles.
    - Local income and property tax benefits as a result of new business in Oregon.
    - Fuel cost savings to Oregonians as a result of lower gasoline and diesel usage and increased overall supply of transportation fuels.
    - Grid-balancing using electric vehicles.
- Account for the environmental, health, and other social co-benefits. Although the purview of this economic study is ostensibly to just account for the gross state product impact and not the externalized costs and benefits of an LCFS to society, it is essential that these impacts be reflected through at least a detailed and thorough literature review. In particular, the following should be considered:
    - Health impacts from decrease air toxins and particular matter.
        - Asthma rates
        - Cardiovascular diseases
    - Environmental hazards and costs associated with producing and using fuels
        - Climate change

        - Oil spills
        - Coastal dead zones
    - Improvement in Oregon's trade balance from decreased oil imports and becoming less of a fuel price taker and more of a fuel producer.
    - Avoided environmental regulatory costs.
        - Clean Air Act costs, such as ozone compliance.
        - Early action to reduce greenhouse gas emissions will ease the economic transition to a national comprehensive climate policy such as cap and trade or carbon fees.

- Account for administrative efficiencies. With several other states working on LCFSs, Oregon stands to gain significant cost-savings from using the shared knowledge, tools, and experience of other states – especially California.
- Estimate the impact of the 2015 sunset. The LCFS is currently scheduled to sunset in 2015. The economic study correctly will consider the impact of the LCFS as if the 2015 sunset does not exist. However, also of importance is delay of removing the sunset on the market for technological innovation and deployment for alternative fuels and complementary vehicles. The economic study should make a separate market impact assessment of removing the sunset under three scenarios: 2011, 2013, and 2015.
- Account for post-2020 impacts. The upfront incremental cost of alternative fuels and complementary vehicles is likely to be substantial, the long-term fuel savings to the owner is also likely to be substantial but spread out over several years. When making a vehicle purchase, the owner will account for both the upfront costs and the long-term benefit. But an economic analysis that accounts for the costs and benefits of a vehicle to the owner in a given year will exaggerate the costs. A car purchased in 2020 will have substantial costs in 2020 and nearly zero benefit, but those benefits are real and will be accrued in future years. Since the "payback" period on the purchase of a $35,000 plug-in hybrid might range from 7 to 11 years, we suggest that the economic study account for the benefits through at least 2033 (for a 2022) LCFS reduction target).

- Use the 2020 horizon compliance year. The language of the organic legislation for the LCFS plainly makes clear that the state Environmental Quality Commission is authorized to create a schedule to achieve a 10% reduction in the greenhouse gas emissions intensity of fuels *by 2020*. Given the legislature's intent to achieve the state 2020 climate goal and the physical carbon constraints mankind now operates must now under, we interpret the 2020 statutory year not as a ceiling for which the Environmental Quality Commission cannot go any earlier, but rather a floor that the Environmental Quality Commission cannot go beyond to fully implement the LCFS. In order to stabilize the Earth's atmospheric concentration of greenhouse gases at the lowest possible amount will require frontloading reductions as soon as possible. The LCFS legislation was a cornerstone climate policy during the 2009 session to achieve the 2020 state climate goal. Any delay in implementing the LCFS frustrates the state's ability to meet the state climate goals and will require compensatory climate reduction strategies that will likely be more cost prohibitive. In order to make the case to the public for fully implementing the 10% reduction target by 2020, the economic study must analyze the economic impact of doing so. Given that the legislature authorized the Environmental Quality Commission to implement the 10% reduction target *by 2020* and given the physical nature and state goals for carbon constraint that the state now operates under, the economic study should use 2020 as the horizon year, and not any later date.
- Account for transition in LCFS schedule to indirect effect accounting. Environment Oregon believes that indirect effects are a critical component for conducting a lifecycle analysis of transportation fuels. We also recognize that the science is not yet settled and we believe that we should continue to process new information and research and then formally adopt the best available science in 2013. This phase-in of the

indirect effects data will have a small but perceptible impact on the compliance scenarios, which should be accounted for in the economic study.

July 7, 2010 Advisory Committee Meeting

- Two years ago, who knew that oil would peak at a $147 a barrel. Today it was $73 and it has been about $68 to $85 in the last several weeks. Nobody predicted $147 a barrel two years ago, or the plummet down to below $40 a barrel a few short months later. So it really is difficult to predict.
- It seems like part of the advantage of encouraging biofuel production is to give us a little more robust system and not be crippled by volatile fuel prices, and if the benefits of that are not incorporated in the economic analysis, then I think you are missing something.
- If you have a monopoly and you add in some competitors then it gives you some resilience in your economy. right? So, does that come out of the REMI model? And the focus is 10%, which is probably pretty small, but is that considered?
- I think this came up last time, which is that we are essentially a price taker and low carbon fuel standard isn't likely to change that in a huge degree, although maybe if we huff it after 2020 or 2022, we might become more of a price maker.

Summary of written comments from advisory committee member or alternate July 15, 2010

- Environmental and public health co-benefits. Petroleum-based transportation fuels emit smog-forming compounds and particulate matter that contribute to air pollution linked to asthma and cardiovascular diseases. Oregon residents that live along high traffic and congested roadways suffer disproportionately higher rates of these diseases and tend to be marginalized communities. The health savings associated with reducing petroleum-based fuels should be evaluated and the equity impacts should be considered. Analysis of these benefits have been conducted and verified and those results could easily be indexed to the fuel blend changes forecast in the economic models. Environmental costs that should be considered include: the cost of oil spills to Oregon's water and land; climate impacts on health, wildlife, and industry; and the benefits of replacing internal combustion engines with electric engines (e.g., the reduction in non-point source pollution, such as oil spilled during oil changes and roadway runoff).
- New and emerging businesses. The low-carbon fuel standard will help create a market for new fuels that will create new businesses related to production, distribution, and refueling. Because many of these businesses do not yet exist, the cost to existing suppliers may look outsized compared to the benefits of these new industries. Estimates of direct and indirect job creation, new tax revenue, and lower fuel costs should be evaluated. Our experience with biofuels employment per gallon of production in Oregon and the need for advanced fuels to meet LCFS targets should be easily considered by the economic model.
- Benefits of reducing oil use. Oregon imports 98 percent of its transportation fuels. The LCFS should reduce demand for oil so improvement in Oregon's trade balance should be evaluated. Similarly, the benefits of diversifying the transportation fuel pool as a buffer against oil price spikes should be included. Because Oregon policies often set the stage for national action, the larger economic and security benefits of reducing oil use should also be considered. Because oil prices are particularly difficult to predict into the future, the analysis should evaluate a range of oil prices and ideally also include a nonlinear scenario that includes price spikes such as those that occurred in 2008.
- Corollary benefits. Oregon's adoption of a LCFS puts the state ahead of the curve for potential compliance with federal programs. Historically, Oregon has benefited from such leadership. For example, Oregon was an early adopter of clean car standards at the state level. A federal standard was

recently adopted and Oregon already meets the requirements. Adopting the LCFS could potentially allow Oregon to capture a larger share of the renewable fuels market for in-state producers. Oregon is also part of a larger West Coast green highway initiative. Both California and Washington are working on a LCFS. Oregon's proximity to these markets gives low-carbon fuel producers an advantage to exporting to these other markets, especially California's large fuels market.

- The economic analysis should also take into consideration impacts of the 2015 sunset. Emerging businesses need the certainty of longer time horizons to make investments. OEC also supports including analysis for the 2020 horizon in addition to the 2022 timeframe.

August 10, 2010 Advisory Committee Meeting

- Does this model map changes in wages and prices for goods that are going to be driven by this increase in construction? *Response (ML): Yes, it does.*
- Will you be writing scenarios where the plant is in Boise, Idaho rather than Oregon? *Response (ML): Yes, but it's just a matter of whether it's in Oregon or outside of Oregon.*
- Are you trying to get to a net figure of economic activity statewide, or do you have it be more complicated than that? For example, under some forecast scenarios, I could see consumers in urban areas losing out on a higher gas price, but construction workers in eastern Oregon doing quite well – and on a net basis, very little change. *Response (ML): Geography is built into it, so it can be run for individual states, it can be run for individual counties, you can run it for a metropolitan area. However, we're not going to take the REMI model down to the county level for this purpose.*
- How does the model deal with technological issues? I'm sure there are a lot of things to work out with existing industries and new industries that emerge. How does one allow for that? *Response (ML): It's not able to predict; what it does is take a look at the rate of technological change, and it builds the same rate of change into the future.*
- Does this approach capture any of the implications on consumer welfare? *Response (ML): No, it doesn't.*
- My main comment is that I don't trust nearly any oil price estimates especially EIA's. While not a paranoid doom and gloom peak oil freak, I have read enough - including DOD research, that leads me to believe this won't be a comfy slow transition. I think price shocks will occur. Sadly though, I think folks will casually absorb any increased costs that may be associated with Alberta sourced crude.
- My other comment is that I don't believe a cost of carbon will be felt at the pump. At most I think we are looking at 20 cents per gallon - which falls well within what people regularly tolerate and may not even notice. Which also leads me to state that LCFS caused price changes will likely go unnoticed by anyone that is currently subject to the dynamism of the market.

Summary of written comments from advisory committee member or alternate August 24, 2010

- Any oil price estimates are not trustworthy, especially Energy Information Administration's. I have read enough - including DOD research that leads me to believe this won't be a comfy slow transition. I think price shocks will occur. Sadly though, I think folks will casually absorb any increased costs that may be associated with Alberta sourced crude.

- A cost of carbon will not be felt at the pump. At most we are looking at 20 cents per gallon - which falls well within what people regularly tolerate and may not even notice. Which also leads me to state that

LCFS caused price changes will likely go unnoticed by anyone that is currently subject to the dynamism of the market.

Summary of written comments from advisory committee member or alternate October 6, 2010

- I believe that any legislation, regulation, rule, or standard must consider the impact to people and jobs--today's jobs. Many will emphasis the POTENTIAL, but I encourage the DEQ to assess real jobs that currently exist and may be lost by such actions. As such, I'll reply individually to your questions.
- With so many variables, including the current ongoing economic crisis and potential for research and development, I propose adding an economic "barometer." If the unemployment rate, consumer price index, or some other measurable data does not trend positively, I encourage the DEQ to assess its actions before adding to the situation in a negative manner.
- This could lead to job creation but may eliminate current jobs. Oregon is not viewed favorably from a regulatory perspective, and unless we address it, our work to be an innovator in "green activities" may be futile. Too often our intention to make a positive impact has led to requirements which cause unnecessary problems, increased costs, etc. As we consider elments of an Oregon LCFS, let's remember that we must feed people. We cannot work against energy. Look at the existing barriers--inability to draw water from the Columbia, the salmon, etc. As we want to do more, how will the current known barriers be mitigated?
- Should early adopters be punished while laggards are rewarded?
- This is positive if agencies collaborate, specifically the Oregon PUC and DEQ. Where does the Oregon legislature fit in this mix? What about people and jobs? Good, family-wage jobs must not be lost.
- In summary, I hope the Oregon legislature, PUC, and DEQ can collaborate to ensure jobs are not lost, people are not disheartened, and businesses relocated or avoided due to restrictive regulations. I know a lot of resources--time and money--have been invested. Let's make sure that we do not take actions which will be even more costly later.

October 14, 2010 Advisory Committee Meeting

- Michael mentioned uncertainty associated with a range of compliance scenarios; can you speak to the confidence intervals of the models used to generate the economic analysis given a swing of global economic conditions? ***Response:*** *(Michael Lawrence, JFA) The difficulty in forecasting lies in predicting the level. It is much easier to predict the change in the level as opposed to the level itself. The process focuses on the change and not the level, and predicts how much the level will be impacted by the compliance scenarios. The scenarios were provided to JFA and are intended to represent a wide range of alternative supply scenarios to meet the standard as designed. The idea being that the range of scenarios would capture the future reality of Oregon's fuel mix, and if that future fuel mix turned out not to be captured by the compliance scenarios used in the economic analysis, the model may need to be run again. Hopefully we'll learn as we run the model in terms of the economic impacts how the economy is changed by particular changes in the scenarios, such as changes in fuel price, indirect land use change values, fuels sources, etc.*
- Are you only using one baseline assumption in all compliance scenarios? ***Response:*** *(Michael Lawrence, JFA) There is only one business as usual baseline, and all of the eight scenarios are compared against that baseline. There are a number of paired comparisons, such as in scenario F and G, which consider both high and low fuel prices against the baseline, where as scenario C compares the median price to the baseline.*

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- On the chart titled '*Biofeuls used in Oregon Low Carbon Fuel Standard Compliance Scenarios in 2022'*, it looks like there is a high and low oil price in the business as usual case as well. ***Response:*** *(Scott Williams, JFA) With regard to the fuel baselines, JFA ran the high and low fuel price scenarios against the same baseline, but we applied the fuel price modification to both the baseline and the scenario. So the baseline did get an adjustment, but other than that, no changes were made to the baseline or any substantive fuel source or other economic or fuel-based assumptions.*
- Will the matrix of assumed fuel prices used in the compliance scenarios be made available to the committee? ***Response:*** *(Michael Lawrence, JFA) Yes. As JFA finishes the review process, we will be preparing a final report which will provide great detail on the entire process from the scenario development through the micro modeling (VISON), conversion of VISION outputs into inputs for the macro modeling (REMI), and analysis of the macro model outputs. The final report with all the associated data will be provided to the committee for review.*
- It seems counterintuitive that in scenario E, which is a one-pool scenario, you'd have increased biodiesel and diesel spending. ***Response:*** *(Michael Lawrence, JFA) That is one of the results that prompted me to say that these results are still preliminary. One of the issues with a one-pool scenario is the potential for fuel switching of light duty to diesel consumption. If we go back and look at scenario D, we see a drop in gasoline consumption, and it doesn't appear that the up bars are sufficient to balance the gasoline drop, so that may be a substitution diesel for gasoline, but still need to go through the data and verify that is indeed what is happening.*
- Does the 120+ miles per gallon figure for the energy equivalent to gasoline gallon for electric vehicles on slide 21 of your presentation take into account all the way up to generation, or is it end vehicle use? ***Response:*** *(Scott Williams, JFA) All fuel inputs are full-cycle inputs and they use GTREET to generate an emissions factors that attempts to include all the elements of the process of producing, delivering and transmitting that fuel up until final consumption. The "gallons" in quotes is an energy equivalency drawn from an AEO projection of vehicle efficiency of a light duty vehicle running on electricity as a fuel.*
- For clarification, looking at the bar graph for gasoline on slide 19, do the bars below the x- axis mean that relative to the BAU there will be less gasoline expenditures, but the expenditure could still be more than it is today because that's a change off the baseline? ***Response:*** *(Michael Lawrence, JFA) That is correct.* So it doesn't mean that there is an actual reduction in spending on gasoline, but it's a reduction relative to the BAU case in the future? ***Response:*** *(Michael Lawrence, JFA) That's correct.*
- The JFA presentation talks about an energy efficiency ratio of four for electric vehicles, and the committee has talked about using an EER of three in prior meetings. Did you use three or four in the economic analysis? ***Response:*** *(Michael Lawrence, JFA) We did not use any, because that comes out of the VISION model run by TIAX, and that was a decision made by DEQ.* ***Response:*** *In a previous committee meeting, we discussed using an EER of four and having it decline to three, because today's electric vehicles are four times more efficient than gasoline powered vehicles but in the future, because of the fuel economy standards for gasoline vehicles, electric vehicles will be three times as efficient.* My recollection of that discussion is that we didn't reach a decision; I thought we settled on three. ***Response:*** *DEQ proposed an EER of three, but the advisory committee had a lot of comments about that. And then in the cost assumptions that TIAX presented, that is what they said.* ***Response:*** *(Scott Williams, JFA) I have the model in front of me now, and the EER values used were about a four to one ratio in 2010 and three to one in 2022.* ***Response:*** *DEQ needed to adjust the values to account for the fact that California gasoline is reformulated, and Oregon gasoline is not. So the actual values used by TIAX were 4.1 for 2010 declining to 3.1 in 2022.*

- I realize this is an economic analysis and not a consumption or emissions analysis, but is it possible to get a chart that shows where the BAU consumption line is going under these compliance scenarios, as well as emissions, so we could see not just what the cost impact is of the scenarios, but also the emissions reductions that would occur under each scenario compared to the business as usual line? ***Response:*** *(Mark Reeve, Chair) The statute includes overall emission reduction, but even on the economics business as usual we need to know if petroleum usage is going up or down and what the usage looks like in 2022. At a minimum, you'd want the inputs for the economic model to be consistent with other findings for consumption trends.* ***Response:*** *To clarify, all compliance scenarios are designed to meet the emissions reduction goal of HB2186.*
- The baseline is using a proportionate allocation for all states' RFS2 requirements? ***Response:*** *(Michael Lawrence, JFA)* Yes.
- Micro impacts for scenarios A. B, C, D and even D don't show anything off of baseline until 2017 or so. Anecdotally, it seems like there is already more spending than what the graphs show. ***Response:*** *(Michael Lawrence, JFA) This graph is only showing expenditures for ethanol and biofuels plants (production facilities,) it does not include the infrastructure for electric charging systems.*
- Is the big hump on the line graph (slide 43) due to construction of biofuels facilities? ***Response:*** *(Michael Lawrence, JFA) That's correct. We cut off the analysis at 2022 so we can't see what's going on after that, but if we went 40 or 50 years out, we wouldn't see this much drop, because we'd see pick up of employment at those facilities and new construction as demand changes over time.* So that end point at 2022 is not the ongoing operational level? ***Response:*** *(Michael Lawrence, JFA) It is the operational level.*
- And are these direct or induced impacts? ***Response:*** *(Michael Lawrence, JFA) These are the macro economic impacts which are the result of the direct impacts, so this is only showing the direct, indirect and induced changes in economic activity that has been provided to the model. The direct impacts are fed to the model, and the model calculates indirect and induced impacts.*
- What type of a multiplier does this type of attrition generate? ***Response:*** *(Michael Lawrence, JFA) I don't have that number off hand, but it's probably in the two to three range.*
- In some of the charts the start year used is 2012, but this chart (macro outputs of employment) begins in 2010. What is our starting point for measuring? ***Response:*** *(Scott Williams, JFA) The sum values are 2012 through 2022. The models start in 2010 because they build each year so they have to start from now, but the analysis period is 2012 to 2022. In theory we could have shown the charts as starting in 2012 because 2010 and 2011 are not part of the analysis period, but when we sum over the period to calculate the total impacts, we're doing it only for 2012 to 2022 .*
- Scenario D seems out of whack because that means you're adding significant additional new jobs each year, rather than creating jobs and keeping those same jobs. This seems to be adding incremental new jobs on top of last year's incremental new jobs more than it should. ***Response:*** *(Michael Lawrence, JFA) The expansion of the electric infrastructure continues, and that's why job growth continues under that scenario.* At some point you reach a steady state, and then you'd have population growth.
- In terms of the numbers, are those job years, or actual jobs? ***Response:*** *(Michael Lawrence, JFA) Those are job years. It's the sum of the employment over each of the analysis years.*
- There's something else at work here. Scenario D has three very different economies at work coming up, so it adds to the notion that when you're looking at infrastructure for some of the alternative fuels you see a multiplier effect adding on to a cumulative effect of three different sectors growing at the same time. So

you have three different kinds of labor economies, three different sets of markets, and three different sets of processes being modeled together as one scenario.

- In this morning's paper, BP and Arco announced that they will be installing electric charging stations soon, which I assume means before 2012. Does that modify the business as usual case, or is that counted as future growth? ***Response:*** *(Michael Lawrence, JFA) I don't know the answer off-hand. If we thought there was a reason to change the business as usual case due to some fundamental change in what we believe to be investment strategies unrelated to this rulemaking, then it might be worth looking at the business usual case and whether it should be reconsidered. We're not creating the business as usual case, we are using the Department of Energy's forecast and modifying to be Oregon specific, but it is their extrapolation of history and what they expect going forward.*
- Is there any thought on what effect the recent increase of the federal blendwall for the ethanol standard might have on the compliance scenarios? ***Response:*** *Six of the eight compliance scenarios modeled include E10 as the blendwall, and Scenarios B and C have and E12 blendwall starting in 2017 which increases to E15 in 2020.*
- Does the analysis include the infrastructure investment needed for blender pumps? ***Response:*** *TIAX did include additional infrastructure costs for ethanol for some of the scenarios, but I'm not sure exactly what those costs were.*
- **Andy Ginsburg:** Under scenario H, if we're assuming out of state production of ethanol to meet the requirements of the LCFS, Oregon will already be receiving its proportionate share of ethanol to meet the requirements of the RFS2, and in order for the comparison to be apples to apples we probably need to adjust the business as usual case to reduce the in state production. I'm wondering if we are creating an artificial effect in terms of the net, if we're just looking at the net difference from business as usual. It's something to think about when analyzing the data to make the comparisons apples to apples, the same way changing the fuel prices does. ***Response:*** *(Michael Lawrence, JFA) That adjustment would eliminate the negative bars.* ***Response:*** *(Mark Reeve, Chair) It's an important point and something to think about and work through, not for immediate resolution, but as something to think about.*
- Are we assuming that Oregon is the only state that adopts a LCFS in this analysis? ***Response:*** *(Michael Lawrence, JFA) We're not making that assumption at all. We're indifferent in this analysis to what happens with low carbon fuels standards outside of Oregon. We are making assumptions that alternative fuels are available to meet these requirements or inputs available to meet requirements of plants that might be constructed.* Where the plants are built depends on where the fuel is needed due to transportation issues, and if Oregon were the only state to adopt a LCFS, under that scenario, the incentive to build plants to supply that fuel is in or close to Oregon. But if it becomes a national standard, or regional standard, then the incentive to build plants gets focused largely on areas with high populations. It is unclear why the business as usual scenario changes at all, assuming there will be broader adoption of the standard throughout the nation. ***Response:*** *(Michael Lawrence, JFA) There is already a substantial amount of ethanol produced nationwide, and the assumption imbedded in these scenarios is that there is an opportunity to produce fuel in Oregon, and DEQ has made an analysis of the various fuels supply options, and the compliance scenarios break down where those fuels would come from. If the fuel indeed comes from those modeled sources, there will be required capital investment to gather the feedstock, process the product and distribute to the market place, and those capital investments and associated employment are the positive economic impacts associated with these rule, assuming that the scenarios accurately reflect what occurs in the future. If you continue to ship dollars out of state for ethanol just as you do for petroleum, there will be no positive economic impacts from the standard. The positive economic impacts come from the change in the overall economic structure in Oregon so that Oregon becomes a fuel producer and not just an importer.* ***Response:*** *DEQ will make*

available the table that will show where the fuels are assumed to come from and in what volumes once we've double checked the data.

- The baseline in REMI has input on the projections where if you go farther down, you have some sectors that are changing constantly, and in neighboring economies, as in neighboring regions, you are seeing state management or voluntary efforts to explore low carbon fuel options or infrastructure. And that is impacting the cost, quantity availability, and even technical know-how, which is something we need in Oregon. And that is influencing to some degree the ease and degree of which low carbon fuels could perhaps be easily explored, or explored at what cost, given that we are cost takers.
- If we're looking at Oregon in isolation, have we calculated in an avoidance factor? Given our aversion to biodiesel at the moment, and if there is a price differential, then there should be an avoidance factor for both rail and trucking, because we are capable of buying fuel elsewhere. ***Response:*** *(Michael Lawrence, JFA) We can think about that in the change – remember what we provide to the model is dollar expenditures for fuel and if we were to reduce that by some portion we'd have less impact. That could be done but the fuel taxes would still have to be paid to Oregon since you pay taxes on where you drive.* Oregon doesn't have a fuel tax. ***Response:*** *(Michael Lawrence, JFA) The weight-mile tax applies.*
- Michael mentioned the only benefits in this analysis are due to the plant construction in-state. With the scenarios being discussed, would this avoidance factor then eliminate that positive impact and add a negative to it? ***Response:*** *(Mark Reeve, Chair) I thought I heard Michael say that it would be an overall reduction of fuel use potentially, and if truckers that fuel their trucks in Washington drive through Oregon and re-fuel in California, what percentage of fuel use in Oregon it could represent. And that percentage reduction of fuel use would come off the overall gains and losses running through the model, so unless you have a huge plant that is anticipated to be built doesn't get built, I'd think you would bring down those benefits proportionately.* ***Response:*** *(Michael Lawrence, JFA) I'd have to think about it a little more, but I can't think of any other. You have to pay fuel taxes in Washington and weight mile tax in Oregon, so that would make it less desirable to try to avoid re-fueling in Oregon.* That's not correct, the tax system is based on where the fuel is burned, not where it's purchased, so you're going to pay the same amount of tax no matter what state you're in. So tax is not a motivator. ***Response:*** *(Michael Lawrence, JFA) In terms of location of fuel purchase.* Correct. While I agree with you that the total amount of fuel we're talking about is small because gasoline is consumed in much larger quantities than is diesel in Oregon, but it is a significant portion of the diesel consumed. ***Response:*** *I think it's an effect they could explore, maybe as a sensitivity analysis of "x" amount of fuel is able to be purchased out of state.* You're missing the point, because at one point we said we're looking only at Oregon, and now we're looking at effects of a LCFS regionally. ***Response:*** *No, I'm not looking at it regionally, I'm questioning whether your scenario of avoidance is realistic when you consider that California already has a standard, Washington is considering a standard, and our indication is that the price isn't going to be different and so you have a scenario that we could look at sensitivity on to see if it makes a difference.* Based on what you're saying the investment scenario needs to reflect that there is going to be demand for low carbon fuels in Washington and California too because of their standards, which would impact the location of plants.
- We can't assume that all these biofuels plants will be built in Oregon because California and potentially Washington also have a LCFS, and plants will likely be built in locations with large populations. ***Response:*** *There isn't an assumption that all these plants will be built in Oregon. If you look at all the scenarios, there are some in Oregon, some in the northwest and Midwest.*
- If there is avoidance in diesel, the likely outcome is that you shift to a different scenario, because you have to comply with the standard based on the fuel burned in the state. In all scenarios except for H, the benefit was there so the impact is still positive. ***Response:*** *If we have two pools, whereby gasoline and*

diesel are treated separately, I don't think gasoline is affected by what happens in diesel. But if the effect of the diesel scenario is that less fuel is sold in Oregon, they would still have to meet the standard for the fuel that is sold in Oregon so you'd still get the ten percent reduction but there would be less total fuel sold. So we'd still get the same environmental outcome for our state, but that would be a negative effect for the Oregon economy. It would be similar if you reduced vehicle miles traveled in any sector, it's just less fuel sold in Oregon.

- This raises the question of how we're accounting for compliance. We discussed using the weight-mile tax as the numbers we'd use for the net amount of fuel used in the state, and if we're using that number to hold accountable the system, then we would have to figure out how that would work.
- My understanding is that the statute indicates fuel sold in Oregon, not used. ***Response:*** *(Mark Reeve, Chair) Under a one-pool scenario, if diesel is part of the one-pool scenario, I think there would need to be a shift to some other biofuels.*
- This doesn't seem to look at some of the roll-out impacts of the compliance scenarios. For instance, in the high electric scenario, it doesn't show any negative losses as a result of that scenario being implemented. For example, if you have more investment going into electric vehicles and more people driving electric vehicles then you're going to have a reduction in conventional petroleum and or ethanol blended fuels consumption. And as a result of that, you're going to see a reduced need for stations and associate job losses, and this doesn't show those job losses, does it? It only shows the positive? ***Response:*** *(Michael Lawrence, JFA) No, it shows both the positive and the negative. The macro-model is provided information on the change in individual sectors. For example, in the purchase of petroleum products either by households or by industry, the model is provided that change so there is a reduction in all cases. In the graph with the change in fuels and the high and low bars (slides 19 & 20), that's a reduction of activity in the petroleum sector and that information is provided to the macro model to run the change so it includes the reduction in output from the petroleum sector and all of the inputs that might be required for petroleum. So it includes the petroleum distribution system, less transportation purchase, less fuel distribution infrastructure. The macro model is a very aggregated in its process, so it is looking at the change in dollars and is not focused as much on the specific subcomponents of production and distribution of the product. It would not tell us, for example, that instead of having X number of fueling stations we'll only have Y number of stations. What it does tell us is that the output of the petroleum sector is reduced and that reduction in output reduces GDP, reduces employment, and it reduces personal income by amounts that are associated with a particular industry.*
- Does the graph on slide 36 reflect the job losses associated with the decline in the demand for fuel? ***Response:*** *(Michael Lawrence, JFA) That's correct, in the reduction of output from the petroleum sector.* ***Response:*** *This is the net effect, and in the more detailed report that JFA will make available to us we will be able to see what occurs more specifically by sector what goes up and what goes down.* ***Response:*** *(Michael Lawrence, JFA) Correct. The REMI model produces a wide variety of statistics and information on all of the sectors that are included, and all of the macro-economic variables that are being measured. So you can envision a large matrix of data 70 sectors by all of the macro-economic changes. A full set of materials for all of the REMI runs will be included as an appendix to the JFA economic analysis report so anyone can take a look at the details for each sector and industry to see what is changing.*
- Scenario B is the mixed biofuels, so it could be that the petroleum distribution sector might gain more employment because you'd be using that infrastructure.
- Since this is focusing only on Oregon to date, the whole intent of the LCFS is to reduce the use of petroleum, which is going to have a significant impact to the petroleum industry out of state, i.e.

Washington and Utah refineries. If you get to the point where a refinery shuts down, then you're losing all that economic benefit in Washington but you're not addressing that loss here, and that would be a significant loss. So we need to make sure that somehow we capture that, because those losses won't be captured in this economic analysis. ***Response:*** *(Mark Reeve, Chair) I agree, that out-of-state impacts are not being looked at here, and I want to clarify in terms of the intent to reduce petroleum use. I think the intent of LCFS is to reduce the carbon content of the fuel and if those refineries can be used for the production of lower carbon fuels including some of the diesel products being discussed, some of the refineries may or may not see some of those gains or losses.* You also have increase in demand in the business as usual model, and petroleum doesn't go away completely.

- Petroleum is going to be a significant contributor for the next several decades, just like coal and natural gas will be, even though we'll have significant increases in biofuels as we go forward, but those negative impacts are still there and are not being addressed in this analysis. ***Response:*** *To that point, Washington is doing an economic analysis on a LCFS as well so we'll have that information, and we could potentially look at both ours and Washington's reports. These scenarios are being compared to the business as usual case, and we're not necessarily talking about reducing petroleum which we may have to do with the rate of growth. To get to the point where one of these refineries doesn't have enough demand because of a change in Oregon's consumption pattern due to the LCFS is unlikely because we're not that big a proportion of Washington's overall market. But the point is well taken that we should include Washington's analysis. I want to comment on the title of slide 35 – Scenario B is not 100% in-state, it's mixed and so we're talking about a mixed in-state/out-of-state scenario with a pure out of state scenario.* ***Response:*** *(Michael Lawrence, JFA) Understood.*
- The gross economic product slide was for cumulative benefits from 2012 to 2022, is employment also being shown as cumulative jobs and not jobs per year? ***Response:*** *(Michael Lawrence, JFA) That is correct, it is job years as opposed to jobs.*
- Will we see a slide with a graph of fuel price assumptions that were made in the analysis? ***Response:*** *(Michael Lawrence, JFA) I have charts of fuel prices from DOE numbers.* Or any assumptions used for conventional ethanol, cellulosic ethanol, renewable diesel prices? ***Response:*** *(Michael Lawrence, JFA) I'm not sure I have charts for all of them, but I can get those for you.*
- What is the differential between the state product and personal income, what's the driver? ***Response:*** *(Michael Lawrence, JFA) Gross state product is the sum of what is called value-added in economics and value-added is primarily employment, but it also includes other components of state product such as profit or other incidental charges that get included in value-added, usually associated with employment or business activity. They are not inputs to production; they are not the purchase of raw material or component parts.* So personal income is not a component of employment? ***Response:*** *(Michael Lawrence, JFA) Personal income is a large part of value-added because value-added is primarily employment. It is that payment to employment that gets translated into personal income.*
- Is the difference in projected plant construction between scenarios B and C due to increased importation of sugarcane ethanol or other imports? ***Response:*** *(Michael Lawrence, JFA) It is a result of increased importation, so less production would occur in-state.* ***Response:*** *So if we understand this right, indirect land use change (ILUC) might still be very important in terms of an individual producer's carbon intensity and how that translates into their compliance obligation, but the effect on the overall economic picture of the program, it doesn't seem to be a huge driver.* ***Response:*** *(Michael Lawrence, JFA) It doesn't have an impact on the macro model.* Did you use the California ILUC values in the analysis? ***Response:*** *(Michael Lawrence, JFA) Yes.* ***Response: (DC)*** *The California ILUC values were the highest ILUC numbers currently in use, and they were used in the analysis as an upper bound.* ***Response: (AG)*** *Seeing that the scenarios are all relatively close together on the graph (LCFS Economic Impact – Gross*

State Product, slide 43), we could say that ILUC or no ILUC doesn't really have an effect on the economics of the program, and the committee's recommendation should be based on other factors like uncertainty in the data or things like that. Last meeting we talked about waiting for a while until there is more certainty about which ILUC numbers to use and incorporating them at that point, and this seems to say if we did include it, it wouldn't really change the economics of the program. Is that fair to say? ***Response:*** *(Michael Lawrence, JFA) That's fair. Well stated.*

- Are the assumptions for the high and low price oil scenarios in 2010 dollars? ***Response:*** *(Michael Lawrence, JFA) They're constant dollars, and I believe that are 2008 dollars.*
- Is that wholesale without tax? Or what is the normal standard? ***Response:*** *(Scott Williams, JFA) I think that's a full retail price, inclusive of taxes but I'm fairly sure it's a national average with an adjustment for the Pacific region. It's a rounded number – I didn't put the actual figure down to the pennies.*
- Are we going to share with Washington the demands for petroleum in our scenarios to inform their economic analysis and in-state employment? ***Response:*** *I think they are already well into their process.* Did their analysis take into account any reduced demand for petroleum from Oregon as a result of our LCFS? ***Response:*** *(Frank Holmes, WSPA) REMI generated a normal sector.*
- For scenario F versus scenario G, is the picture that the higher the price of gas and diesel the better the LCFS does? ***Response:*** *(Michael Lawrence, JFA) Higher price is resulting in higher economic impact for the state.* So if gasoline prices go up to five dollars per gallon then the LCFS provides more economic benefits to the state than if gas were two dollars per gallon? ***Response:*** *(Michael Lawrence, JFA) Relative to the baseline, yes, and that makes construction of the alterative supply more valuable to the state.*
- Does this take into effect the demand response for the price? ***Response:*** *(Michael Lawrence, JFA) It does. The VISION model includes demand elasticities associated with price for the products, so when VISION determines the vehicle mixes in the future and what consumption of fuel occurs by each technology, it takes into account the elasticity of the price of that fuel, so when price goes up the consumption will be reduced.*
- One of the questions that is still unresolved is whether two use a one-pool or two-pool approach when looking at gas and diesel. What would be the best (two-pool) scenario to compare to scenario E? ***Response:*** *(Michael Lawrence, JFA) It's in the group with A, B, C, E.* Is that similar to the indirect land use piece where that decision would be made based on other considerations and is not driven so much by the economics? ***Response:*** *(Michael Lawrence, JFA) We don't see a lot of variation as a result.*
- Does the gross state production capture state trade balance questions? ***Response:*** *(Michael Lawrence, JFA) Yes, it does.*
- Is there a part of the analysis that looks at the impact of possible future legislative activities around the federal carbon initiatives or taxation of carbon or carbon emissions? ***Response:*** *(Michael Lawrence, JFA) It could have been if we designed it that way, but there is no consideration given here for any legislation that might change fundamentally the transportation sector of the energy sector.* If you look at the historic business as usual, there is none.
- We had asked for a qualitative assessment of what a 2020 horizon year would look like. Has any qualitative assessment been made using the horizon year of 2020? ***Response:*** *(Michael Lawrence, JFA) We have not looked specifically at moving the end year from 2022 to 2020. If the requirement was to complete the introduction of fuels to be available by 2020 there would probably be higher costs. One of the costs of constructing a plant is the lead time, so if you shortened lead times you tend to increase the cost of production. In terms of the actual impact of those investments, whenever they occur they produce these economic benefits.* ***Response:*** *It seems like we could maybe have a couple paragraphs talking*

about how using a horizon year of 2020 would result in capital investment earlier which would be a benefit, but it could raise the costs due to less lead time for construction of new plants. I think there are other factors that could affect the VISION runs because you may have trouble getting to the needed biofuels volumes which might make some of the compliance scenarios less feasible or practical. There could be administratively as well, and I think we could describe the impacts qualitatively and what would tend to move it in the positive direction, and what would tend to move it in a negative direction.

- Could there also be a brief discussion in the report on what the kind of value money would have? Because when the horizon year changes, that becomes a point of question. Not just a year by year value, but the value of the program today or better yet, in the horizon year? ***Response:*** *(Michael Lawrence, JFA) Sure. The sooner you get the benefits, the more the value.*
- What was driving the investment dates? Was it when we thought the technology would be ready, or was it pushed out? Because to me they looked a little bit late. Like plant construction doesn't begin until 2017: was that because the horizon year was pushed out to 2022? What are the variable that were influencing that? ***Response:*** *(Michael Lawrence, JFA) It's one to two years ahead of consumption. So the plant is put in place at a time when anticipated demand for the product will occur when the plant goes online.* ***Response:*** *There's another factor there too which is, construction that will be happening earlier is driven by the RFS2 requirements so it's not differential from the base case to the scenario cases. So you don't see that showing up in this analysis, even though it's happening.*
- The WCI effort using the energy 2020 model has accounted for a potential cap and trade scenario, one which is low carbon fuels, what's called complementary policy. And that data accounts for potential different levels with VMT changes and vehicle efficiency and a low carbon fuels option. So there is some of that information available on the WCI website there is some recent information that accounts for at a more regional level the trade effects and effects of a local LCFS coming up.
- For the scenarios that use the high and low price scenarios based off of gasoline prices, did you take the baseline or average of the projected ethanol price as a comparison? Because I would think there could be quite a difference if there was a high gas and a low ethanol versus a low gas, high ethanol. Those would affect each other. ***Response:*** (Scott Williams, JFA) *I believe the ethanol prices did change along with the AEO projections. It appears that ethanol does have a greater price advantage against gasoline in the high price scenario even though it does change, it rises a bit less and it has a better price ratio against gas in the high scenario than the low scenario.* Is that on an energy content, or a gallon content basis? ***Response:*** (Scott Williams, JFA) *It's a price per BTU, price per gas gallon equivalent energy content. Although the difference in the ratios would change in the same way, however we measured it. Slides 51 and 52 are the last five years of AEO price projections of the baseline. The difference between high and low would be shown on slides 53 and 54.*
- Regarding the blend wall, if starting next year every car sold into Oregon was FFV (flex fuel vehicle) compatible, the scenarios that are laid out could change drastically, and would allow much more flexibility in the compliance of the LCFS. I want to raise that because as we develop the LCFS, we can't ignore the vehicle component, and it is a policy position well within the framework of the LCFS. ***Response:*** (Mark Reeve, Chair) *For clarification, that would lead to higher biofuels consumption.* Potentially, it would allow the flexibility for that to happen in terms of compliance scenarios. It's not mandating anything, but having cars that can run on any level of biofuels, which is one way to address the blendwall issue. ***Response:*** (Mark Reeve, Chair) *From an economics standpoint, having a higher biofuels capability to some extent drives more instate benefit to the extent that there is more demand for capital expenditures. If you include E85 as creating higher infrastructure costs, that would increase economic activity with infrastructure development. Are there some expenditures already built into the*

baseline, in terms of E85 infrastructure? ***Response:*** *(Michael Lawrence, JFA) I'm not sure.* ***Response:*** *(Scott Williams, JFA) Infrastructure meaning additional ethanol fueling stations?* Yes.

- It's not necessarily E85 we're talking about in this type of situation. If all new gasoline powered cars were FFE compatible like they are in Brazil, which costs about $50 per car at the most, and then you're not just talking about E85, you're talking about whatever the consumer wants, based upon the economics. And you're not just talking about blender pumps, and it may be that 30% biofuels is what is most economic for the consumer on a given day. So it's total consumer driven/price driven compliance. I'd like the committee to think about, as we move forward, should there be a vehicle component.
- Are you suggesting that by rule DEQ could have an influence on that? ***Response:*** *(Committee member) Yes, I am suggesting that.* ***Response:*** *That is beyond the scope of this committee's task.* I don't think it should be, because this is the fatal flaw in the California program. They've gone ahead and implemented a LCFS program based on a compliance scenario of 30% biofuels market penetration and there's no way to get there. Do we want to go down the road of having a LCFS and now way of getting there? ***Response:*** *In all of these scenarios, we can meet the LCFS greenhouse gas reduction goal with E85 and the gradually increasing blendwall. These are all realistic scenarios, and the reason we are doing scenarios is to bound reality. If the reality that you are hoping for comes true, it will fall somewhere in the range of those scenarios. We're not precluding it or requiring it, we're just trying to balance it in the analysis. Unless you think we've missed some scenario and another bound is needed to capture that, I think it's somewhere in between the high and low ethanol scenarios.* **Question:** But you aren't precluding by rule requiring any change to vehicles? ***Response:*** *As part of this rulemaking, we aren't going to have any vehicle regulations if that's what you're asking.* That is exactly what I'm asking. The place where it seems like it matters the most is in the assumptions for vehicle fleet. That's where we have control over the input assumptions.
- ***Response:*** *To be clear on the bounding, with the exception of two scenarios, the compliance scenarios include keeping the 10% blendwall because that was the reality when we put the compliance scenarios together, and scenarios B and C assume the ramp up to 15%, so that's where you get the upper bound. Washington's analysis has a 15% blendwall, so we can look at their analysis also to get a sense of the variability and the effects on the program.*
- (Paul Bernstein, Charles River Associates on the phone) Do all of the scenarios assume the same level of VMT? ***Response:*** *(Michael Lawrence, JFA) VMT changes by scenario within the VISION Model runs.* The VMT is sensitive to the price of fuels then? ***Response:*** *(Michael Lawrence, JFA) Correct.* Do you have any information on how the VMT changes across the scenarios and what the prices of the fuels are both individually and the weighted average fuel cost? ***Response:*** *(Michael Lawrence, JFA) We have the fuel prices and the VMT numbers in the VISION runs, but not in a slide or table to hand out today, but we can certainly provide them.*
- (Paul Bernstein, Charles River Associates on the phone) Regarding the discussion about bounding the scenarios, isn't it possible that you won't have the level of biofuels needed to meet the LCFS? I say this based on the difficulty that is occurring with meeting the RFS2 and the fact that the EPA has delayed some of those requirements. ***Response:*** *We tried to construct scenarios based on realistic assumptions about what could happen, and had a number of committee discussions in putting those scenarios together. It's possible that those scenarios could be wrong, but we are building into the program several types of deferrals that would account for situations wherein the standard was not achievable. So we will handle that type of situation, should it arise, through implementation, and in the analysis it's better to assume that we are able to achieve it so we can compare the scenarios. If we can't achieve it, the program won't achieve as much emissions reduction as otherwise possible, but there won't be a significant economic effect because we would either reduce the stringency or defer the requirements.*

- (Paul Bernstein, Charles River Associates on the phone) For Scenario D (high PHEV Penetration), I'm trying to understand the impact on personal income. If I'm looking at the TIAX assumption correctly on vehicle cost, it seems that the price of electric and PHEVs is a fair bit more expensive than conventional vehicles. Is that true? ***Response:*** *(Scott Williams, JFA) That is true. There is an assumption that there is a significant price premium.* Okay, so if that is the case, it isn't clear where people are getting a boost in personal income. If anything it seems that people will have to pay more for transportation and have less money for other things, and so less money then goes into the Oregon economy. ***Response:*** *We looked into that when we adopted California's low emission vehicle standard, and the analysis came out that when you consider the extra cost of the vehicles, it's way more than offset by the fuel savings, so if you finance your vehicle, the monthly payment is less than your savings in fuel costs, so that there is a net benefit to personal income from EV ownership. It does take into account the timing and financing of it, but it is a net positive.*
- Following up on last week's discussion about the effect of a sunset on the program, this seems to indicate that the economic benefits are eliminated if the sunset occurs. ***Response:*** *I'd like to hear what Michael has to say about this, but we've got a pretty long lag time in new biofuels facilities above the business as usual case in Oregon, and for the long lead times we are assuming that people can plan ahead, but if with the sunset there is enough uncertainty that people aren't able to plan ahead, the net effect might be that it does raise the cost of those plants because you can't start planning until 2015 or so until the legislature addresses the sunset. That uncertainty may make it more difficult to achieve those benefits.* You'd have to make an assumption about how and when the legislature would address it.
- What this lays out very clearly is that because the benefits come later in the program, it is essential that the sunset be lifted. ***Response:*** *Just to be clear, we won't ask the committee to give us a recommendation on this because we won't be able to come to an agreement on that point, but hopefully our final report will identify the effects.*
- We keep referring to TIAX data, and the only information I have form TIAX is dated August 9th. ***Response:*** *Those are the cost assumptions.* But it doesn't' have any cost assumptions for the incremental cost of fuel for each vehicle. ***Response:*** *I can get that to you.*
- Could we also get the fuel prices and carbon emission coefficients in time to review and provide comment on that as well? ***Response:*** *Will the TIAX results be included as an appendix to the report for people to see as inputs to REMI?* ***Response:*** *(Michael Lawrence, JFA) All of the process at each step will be documented in our report. They are not available on the website today, but will be included in the report.* If we need to have comments back to DEQ by next Thursday, we would need to see that data as well. ***Response:*** *There are several rounds of comments. Right now we'd like to capture your thoughts and questions that Michael can be thinking about while he finishes the economic analysis report. When that report comes out that includes the data used to run the models, there will be another opportunity for the committee to provide input to DEQ at that point as well.* But for example if we feel there are other scenarios that are necessary to bound the analysis, we don't have the numbers to make such a recommendation. ***Response:*** *At this point it is too late to add scenarios. What we're looking for is input based on the presentation you've seen today, what other comparisons we should see, what questions do you have about how the analysis was done so that we can utilize that in finalizing the economic analysis report. When you get the final report you'll have another chance to comment on the report itself, but it would be helpful to have an interim round of comments at this point.* Looking at the results we saw today, which are the first time anybody has seen those results, it starts questioning some of the results of the scenarios because they are so closely bound. If you look at the charts for all these results, except for the total electric vehicle case, they're all really close together, and I don't know whether we've truly addressed the bounds or not. They all seem to be clustered, and until we look at the numbers in detail

and the assumptions that went into the number calculations, you're not going to know that. And you can't do that review until you get the final report done, and then we won't have any influence as a committee or as a commenter to make any changes. ***Response:*** *So maybe what you're asking right now is that there be some analysis of the sensitivity of the model to the different scenarios and some explanation in the report about why it's not sensitive to the elements that varied in the analysis. I think that would be good to have some explanation in the report about that because some of it is counterintuitive to non-economists. Maybe another part of your questions is whether we missed some other variables that might be sensitive too, and I don't know how Michael would address that. Are there other things that Washington varied that we didn't that we could look at and see if there was any sensitivity to those?* I'm just concerned that we're not economic experts, so we need to have this available. This is a very significant rule concept that this committee and DEQ are proposing to take on, and if we don't have a complete, true understanding of what's going into this, then I'm not real comfortable with it. WSPA will be looking at it, but if we can't see the data until after the analysis is complete, then that's a problem. ***Response:*** *Rest assured that you'll get a chance to look at it before its final. We don't have it right now, what we have is a preview. If there is some detailed information responding to committee questions raised today we will get you what information we can and then otherwise for now ask questions that will help them write a better draft report, and then when you see the draft report you'll get to comment on that .*

- What we've learned from what we've seen is that the key variables that we've asked to be adjusted in the economic model don't have a great deal of variance across the spectrum of sources for fuel. I think we can ask to disclose additional variables or invite argument about what fuel prices to use, but it's not going to change the outcome.
- We may need to have more time than next Thursday to comment on the draft economic analysis.
- Is the review deadline next Thursday driven by our schedule? ***Response:*** *We need to get comments to Michael so he can write the report.* We want to do this right, not in a hurry, and we need more than one week to review something this complex. ***Response:*** *I think what you want is more time to review the draft report when you have it in front of you with all the appendices and the data, rather than a summary presentation based on draft results.* I'm asking for the data to be available before we give the first round of comments so if we have to make changes to the analysis or the runs that can be done before the final draft is prepared. ***Response:*** *We'd like any initial comments or questions about what you've seen today right away so we're aware of them and can address them in the report. Once Michael is finished QA-ing all the data and assembling it, we'd like you to comment on the full report.* Like I've said at numerous other meetings, hopefully the people sitting around this table aren't just representing themselves and in order to get this out to the constituents that we represent, we need time to gather the data, the data has to be available, we have to get it distributed to our constituents, we have to get consensus positions from those constituents, and to expect that in five working days is unrealistic. ***Response:*** *That's not what we're saying.* That is what you are saying. ***Response:*** *We're asking only for comments on what you've seen so far. We're having a semantic disagreement right now. You will get a chance to see the full data inputs and outputs with enough time for full review and comment; we just need some feedback today to get the draft report out to you.*
- (On the Phone) Regarding availability of data, can you give me an estimate of the timeline to get the tables for the vehicle cost data, the fuel cost data, and the carbon emission coefficients that were assumed? Is that something that can be made available before next Thursday, or should we assume that we won't be able to have that data available for this round of comments? ***Response:*** *We should be able to get that fairly quickly. If there is a specific piece of information that you'd like to see, we can get that fairly quickly. To make the entire body of work available will take a little longer because it still has to go*

through QA, but it will be available for final comment. The TIAX inputs are far enough along that they could be posted for review, and that's what are a lot of people are asking for. The outputs from the REMI model have not yet been QA'd, and we won't be releasing those tables until there has been time to review that, but I think the inputs are available now, correct? ***Response:*** *(Michael Lawrence, JFA) That is correct, the dollar amount of fuel consumption by fuel type by scenario is the fuel price multiplied by the gallons consumed, and that's an output from the VISION model, and that can be provided in table form very easily.* ***Response:*** *The initial preliminary TIAX inputs are available now on the DEQ website, and we need to update them with the final inputs, which should be easy to do because we took input from committee members. We'll do our best to get the outputs from REMI posted on the DEQ website as quickly as possible.* ***Response:*** *(Marc Reeve, Chair) There's always a balance between having enough time to review and getting to a completion point and moving on to the next stage. I will do my best to try and strike a balance that is as fair as possible to all the committee members.* I voice support for having more time to review the final report and all the associated data rather than shorten that timeframe by lengthening this timeframe.

Summary of written comments from advisory committee member or alternate October 21, 2010 regarding the economic analysis

- Disappointed at the extremely short amount of time allowed by the Department to review the LCFS economic impacts analysis inputs and assumptions.
- The amount of time provided and the amount of detailed information provided on the contractors analysis, has been woefully inadequate.
- There are a large number of issues and unanswered questions regarding the information provided by the state's contractors.
- Consistent disregard by the Department of possible additional program impacts, such as program implementation costs, both in terms of substantial DEQ staffing requirements as well as regulated parties administrative costs and individual operators infrastructure burden.

The Charles River Associates report is included here in its entirety.

Critique of Oregon's LCFS Paul Bernstein, W. David Montgomery, Sugandha Tuladhar, Mei Yuan, and Bob Baron
Charles River Associates

Charles River Associates was retained by WSPA to perform a critical review of the scenarios and analysis performed by Oregon's DEQ's consultants in their economic analysis of a Low Carbon Fuel Standard for the Oregon. All opinions, analyses and conclusions contained herein are the authors'.

We appreciate the opportunity to comment on Oregon's economic analysis of its proposed low carbon fuel standard (LCFS). The modeling team in Charles River Associates' Climate and Sustainability Practice has had extensive experience in building and using energy-economy models for the analysis of climate policies, including several recent studies of Low Carbon Fuel Standards (LCFS).

- As part of a study for National Mining Association of the Lieberman-Warner Bill (S.2191), CRA analyzed a nationwide LCFS proposal to reduce emissions by 10% by the year 2020.
- As part of a study on AB 32 requested by California ARB, CRA assessed the cost of California's LCFS program and compared costs under different assumptions about the availability and costs of alternative transportation fuels (http://www.crai.com/uploadedFiles/analysis-of-ab32-scoping-plan.pdf).
- For Consumer Energy Alliance, CRA assessed the economic impacts of a Federal LCFS (http://consumerenergyalliance.org/wp/wp-content/uploads/2010/06/CRA-LCFS-Final-Report-June-14-2010.pdf).
- Most recently, CRA submitted comments on NESCAUM's proposed LCFS study.

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The state of Oregon faces many of the same issues and challenges that we did in our studies and that NESCAUM does. The many basic uncertainties about new fuels technology and life cycle analysis of emissions compelled CRA to develop high and low cost scenarios. CRA, though, was able to use a single, integrated energy-economy model, but Oregon must also cope with the added complexity of having to reconcile a transportation sector model with a separate, and not necessarily consistent, regional economic model. Our comments, therefore, are based on actual experience in conducting comparable studies.

The major points of our review are:

- The modeling approach is critically flawed. Because VISION and REMI models are not internally consistent, as a result the models' reported economic impacts of the LCFS are erroneous and misleading;
  - Model results must be incorrect in showing an economic gain, to the extent that outcome arises from a reference case in which motorists and fuel producers are characterized as acting irrationally and sub-optimally.
  - Model methodology accounts for investment decisions incorrectly.
- The scenarios do not incorporate a wide enough range of uncertainty;
  - The scenarios assume many of the key conclusions, rather than allowing the analysis to determine them;
  - The scenarios fail to reflect large uncertainties in key variables, based upon prior LCFS analyses conducted by CRA. For example the cost and availability of cellulosic ethanol is quite speculative at this point; therefore sensitivity analysis should be performed to reflect this large uncertainty;
  - Policy off-ramps would reduce the possible negative impacts of the LCFS policy, but they would not eliminate them. There would still be sunk costs, such as those incurred with long-term contracts for Brazilian ethanol, from activities undertaken to comply with the LCFS program.
- The analysis ignores the significant costs of implementing an LCFS in the construction of their reference cases;
- Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol facilities will be constructed;
- Incorrect economic indicators of economic wellbeing are used. Gross State Product (GSP) can be a misleading indicator of overall well being of state residents, as can employment changes and consumer expenditures.

Because of the limited amount of time allocated to us to review the economic assumptions and results of the economic analysis, we have identified a number of issues which we have not had sufficient time to thoroughly investigate. As a result, we have included some questions at the end that voice our concerns about how the analysis was conducted.

Flaws with Modeling Approach

The modeling approach used that combines the VISION and REMI models is fundamentally flawed. The VISION model fails to optimize consumer choices and, therefore, modelers determine the vehicle choices in the baseline and the scenarios. If the modelers are not careful, they can add a policy that allows consumers' fewer choices but then appears to make consumers better off than they were in the unconstrained baseline. This appears to be the situation in the state's analysis: when the modelers apply the LCFS policy, they find economic gains in all scenarios except one.

This modeling structure suffers from the additional problem that the REMI model fails to capture losses in consumer welfare and account for the full impact of investment decisions. For example if a policy leads to higher delivery costs for goods and services because the policy brings about an increase in the price for truck fuel, then this will translate into higher prices for goods and services so consumers will be unable to purchase the amount of goods they could have in the absence of the policy. This lower level of consumption is a true loss in consumers' wellbeing. That is, consumers no longer achieve the level of consumption that they would have had without the policy. The REMI model fails to capture this economic loss and therefore the results are biased upward.

Scenarios A through G report positive economic impacts because investment comes into Oregon from outside the state, but there is no discussion or justification why firms would choose to invest in Oregon rather than produce fuels where it is most economic to do so. In fact if recent investment patterns are any predictor of future investment decision, ethanol producers are likely to locate in Idaho and Washington. Allowing money to flow freely into Oregon naturally produces positive impacts because it fails to account for all the economic flows and interactions with other states. Assuming that an LCFS program will stimulate in-state renewable fuels production without targeted supplemental state subsidies (e.g., producer's tax credits, reduced state sales tax) seems to be inconsistent with recent history.

The modeling approach seems to be one in which the LCFS policy simply provides a target for the overall emissions rate of the vehicles fleets. But the decision on how to meet the target is determined exogenously by the modelers who define pathways that quantify the amount of fuel consumed by each fuel type and achieve the LCFS target. These pathways, however, could have been chosen for the baseline and should have been chosen since they are supposedly better for the economy even without an LCFS. Therefore, it seems one is left with two alternatives, either the analysis is not legitimate or these economically better pathways (i.e., the pathways that were chosen when the LCFS is imposed and produce higher values of GSP, employment, and personal income) were not chosen in the baseline because consumers are evaluating their options using different metrics, namely utility or welfare. If the latter case is true, this suggests that the modelers should be working with these metrics rather than GDP, employment, or personal income because utility and welfare reflect the true economic condition of state residents.

The results of the analysis suggest some obvious questions. If all these economic gains are possible from implementing an LCFS policy, then why is the market not undertaking these actions in the absence of any policy? According to the analysis, there seems to be a great deal of money to be made if companies began producing biofuels in Oregon and consumers began driving alternative fuel vehicles (especially electric vehicles from the results of scenario D). If the analysis suggests all these gains, why do regulators need to impose any policy because industry will see gains in output and consumers will naturally want to use these alternative fuel vehicles because they will see a rise in their personal income?

The measured economic gains to Oregon arise because entities outside the state are assumed to shift investment toward Oregon as a result of the LCFS. The study simply assumes the conclusion that fuels will be produced in Oregon, without investigating in any way whether Oregon has a comparative advantage in producing these fuels. NESCAUM also assumed that their own client, the Mid-Atlantic and Northeast states, would be the best places to produce low carbon fuels because of their concentration of high tech firms, and the State of Washington makes similar assumptions in five of the six LCFS scenarios it analyzed. Even if each state were correct that the least cost alternative is to produce locally, then the investment would have to come from within its own borders by displacing consumption and raising the cost of living. If all states were to implement their own LCFS policies in the expectation that they could improve their economy by attracting additional investment, they would all be proved wrong. Nationally, the only source of investment is either reduced consumption or increased borrowing from overseas - that must be paid pack in the future. Thus the conclusion is inevitable that the increased investment required to produce low carbon fuels, rather than conventional fuels, is overall a net cost to the U.S. economy. Since the Oregon LCFS is consciously part of a plan that would have many states adopt similar programs, it is inconsistent to assume that Oregon will stimulate its economy by attracting investment from other states that are not adopting similar programs. But then this leads to the conclusion that if all states implemented an LCFS, the additional constraint on economic choices would reduce profits and consumer welfare. The contrary conclusion of this study violates fundamental principles of economics as well as common sense. But this flawed result follows from the failure of the analysis to consider the full effect of investment decisions throughout the economy.

Furthermore, the scope of the modeling analysis is too limited. The LCFS policy affects other states since Oregon has trade with them, especially given Oregon's lack of refinery infrastructure. Therefore, the analysis should incorporate a broader regional coverage than simply just Oregon. Furthermore, the time horizon is too short. The LCFS policy is not scheduled to simply end in 2022. The continuation of the policy past 2022 has implications for decisions prior to 2022, but to capture this, the model needs to be run out a number of years past 2022 to understand the full effects of the LCFS policy in the near-term (2012 to 2022).

Range of uncertainty

We applaud the modeling teams for using values for carbon intensities, vehicle costs, and vehicle efficiency that fall in the middle of accepted ranges. During our research on the different LCFS proposals, however, it became clear to us that uncertainty surrounded many of the key input parameters. The unknowns greatly complicated the issue. Opinions differ regarding emission factors. They also differ about the cost and rate at which major new technologies would be commercialized and the availability of resources to support those technologies. Taken together these many unknowns lead us to conclude that any analysis used to inform decision makers should consider the range of outcomes for all key input parameters so that decision makers understand the possible range of outcomes from their proposed policy.

Therefore, instead of relying on one set of assumptions for vehicle cost, fuel cost, carbon emission intensities, and fuel economy, we urge the state to build optimistic and pessimistic scenarios that span an appropriate spectrum of possible outcomes. The former scenario should contain the most likely positive outcome for each key input parameter, and the latter one should contain the most likely negative outcomes. Only in this way can the analysis capture the full range of plausible outcomes.

Assuming the conclusions

Based upon CRA's research and analysis, we conclude that the set of scenarios in the Oregon study fail to capture the full range of plausible outcomes. Each scenario assumes that some combination of technologies will succeed. Nothing guarantees this outcome. In fact Oregon presents no case for assuming that it will happen. In effect, Oregon is *assuming* the key conclusion from the study, i.e. that technology forcing is a given. Assuming that alternative fuels (renewable fuels such as ethanol and biodiesel) and plug-in hybrid electric vehicles (PHEVs) will be in plentiful supply and less expensive than their petroleum counterparts invariably leads to the erroneous conclusion that the GHG emission reductions sought by the program can be accomplished without incurring substantial economic costs.

The state's analysis does not justify the view that the new technologies will appear at the cost, and time, with the characteristics assumed. Furthermore, there is no discussion of technology pathways, the adequacy of incentives from LCFS to promote R&D, nor the R&D breakthroughs that will result in technology commercialization. Time and again the economic literature has stressed the profound uncertainties of R&D outcomes,[1] but the analysis done for the state seems to pay little heed. Finally, the consequences from the failure of new technologies to emerge are ignored in the scenarios.

The interpretation of the "technology-forcing role of LCFS" appears to be the only justification for the assumption that technology outcomes will be whatever is required to make compliance with the LCFS possible at negligible cost. Nothing is adduced to suggest

1 Kenneth J. Arrow "Economic Welfare and the Allocation of Resources for Invention" in *The Rate and Direction of Inventive Activity-Economic and Social Factors:* Richard Nelson (ed). Princeton, Princeton University Press, 1962. See also Richard R. Nelson, and Sidney G. Winter (1977). "In Search of Useful Theory of Innovation," *Research Policy,* 6(1): 36-76.

that these mandates, by one state, will have the characteristics needed to force technology to improve. In contrast, research that we have done would suggest otherwise.[2] Assuming that "technology forcing" advances in cellulosic ethanol and biodiesel technology will be achieved in a timely fashion to enable the volumes of low carbon fuels called for by the program are overly optimistic if other states and regions proceed with an LCFS. As of today, cellulosic fuel production technology remains essentially in the development phase, and wide scale PHEV application is unlikely in the absence of a significant distribution network.

From experience, there is clear evidence that the success of technology forcing is not a given. Rather there is clear evidence from other attempts to mandate technology, e.g., electric vehicle (EV) mandates in California, that show a number of unintended responses can occur. For instance, mandates that are perceived by developers as unachievable are ignored. Local or regional mandates are met in ways that are not consistent with the policy objective such as redirecting supplies or through leakage. Only mandates that hit a "sweet spot" involving a reachable goal that is not otherwise likely to be met can be successful. Finding that spot requires careful analysis of current technology status and R&D activities, in order to aim successfully between overly ambitious specifications and specifications that will be met even without the program. Given the inherent uncertainties of R&D, there is no guarantee of success in this endeavor. Therefore, a basic premise upon which the scenarios are based is flawed.

In addition, Oregon should consider scenarios that allow demand destruction of VMT to reduce the required amount of new alternative fuel vehicle sales; and/or large costs for fuel and vehicle infrastructure to be incorporated to achieve the aimed for alternative fuel vehicle penetration levels. Currently, none of the Oregon scenarios investigates the possible risks of the mandates if none of the technologies turns out to be a silver bullet. Should that outcome occur, either the standards must be abandoned or modified, or if they are enforced as written in the scenarios the result will be to drive delivered fuel prices up to the point at which motor fuel demand (VMT) is driven down to a level consistent with available low carbon supplies. This fuel consumption and corresponding VMT reduction is more likely. Furthermore, the higher the carbon intensity of available fuels, the higher the quantity of new fuels required. This outcome cannot be fully represented in any of the models being proposed for use in the Oregon analysis, so that the costs of a failure scenario will never be assessed.

Sensitivity Analysis

Blend wall

For three scenarios (C, F, and G), Oregon assumes the blend wall can be increased to 15% by 2020. Breaking the blend wall has its own set of challenges. EPA have announced a partial waiver for MY2007 and newer vehicles after a protracted analysis period. Extension of this to MY2001-2006 remains under study and MY2000 and older and other vehicle classes/applications are not in view. These scenarios ignore the possibility that consumers will need to purchase the more expensive flexible fuel vehicles if newer non-flexible fuel vehicles or their existing vehicles are unable to burn E15. Furthermore, these scenarios assume that enough fueling stations will find it cost-effective to upgrade and be located in enough convenient locations to achieve the assumed sales.

I LUC

The analysis considers scenarios (specifically C, F, and G) that omit the emissions from indirect land-use changes (ILUC). This is an optimistic assumption and provides the biofuels for which the ILUC is omitted a large advantage.

Need for range of assumptions

The probability of the increasing ethanol content in gasoline to 15% and the value of ILUC should be studied thoroughly. The state is right to have considered optimistic assumptions regarding these two issues in its set of scenarios. But only assuming that biofuels do not result in indirect GHG land use change effects (ILUC) in several scenarios artificially biases these to favor biofuels thereby misleading decision makers on the accurate cost-benefit relationship that the wide scale introduction of these fuels entails. Indeed, the exclusion of ILUC fails to consider the overall GHG implications of biofuel feedstock choices, an omission which could negate the programs sought after GHG mitigation benefits. To be better balanced, the analysis should consider the less optimistic scenarios where the blend wall cannot be exceeded and low carbon fuel supplies do not materialize in large volumes possibly because of issues with ILUC. The clearest case is one in which there is only enough low carbon fuel of any kind that is useable by the fleet to achieve for example a 5% improvement in carbon intensity at reference case fuel consumption. Since the standard must still be met, the only alternative is reducing total fuel consumption, and this will be achieved because fuel suppliers will bid up the price of the constrained supply of low carbon fuels until the pump price rises high enough to choke off demand. This same outcome will occur if the low carbon technologies fail to appear, or new vehicles able to use them are not produced in sufficient numbers, or the refueling infrastructure required to support consumer adoption fails to materialize.

PHEV lifecycle vehicle costs

Using the assumptions for fuel efficiency, fuel costs, and incremental vehicle costs, it appears that applying a bit of sensitivity to the assumptions regarding PHEVs[3] results in these vehicles having higher life cycle costs than conventional gasoline powered vehicles. Given the cost differentials, consumers would not purchase PHEVs unless they were subsidized. The amount of subsidy needs to be accounted for as a cost and reflected in the life-time budget. If the life cycle cost of PHEVs exceeded that of gasoline powered

2 Lane, Lee, David Montgomery, and Anne E, Smith (2009). "R&D Policy" in CEDA Growth No. 61, "A Taxing Debate: Climate Policy Beyond Copenhagen." Available at: http//v.'."■> 'ci orgdocLi&/Lan^:t..I-R-Dpolicv.pdf.

3 Assuming an efficiency of gasoline vehicle of 35 mpg, EER of 3 for PHEVs, and VMT of 10,000/yr in electric mode (that is 2/3 of VMT in electricity mode) results in gasoline vehicles having a couple thousand dollar lower full life cycle cost assuming a 3% discount rate. Raising the discount rate to 5%, a more accepted number, results in an even greater cost advantage for gasoline powered vehicles.

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vehicles, which is clearly quite plausible, the benefits of Scenario D from PHEVs would disappear and become a cost to consumers from forcing them to purchase more expensive vehicles. As regulators have stated, they would suspend or shut down the program if costs rose too much. But there would still be some economic damage, especially in terms of sunk costs such as long-term ethanol contracts with Brazil, that would result from agents attempting to comply with the LCFS. We are advocating for a scenario to be analyzed the incorporates this very real possibility.

Reference Case

The Oregon analysis assumes full implementation of an RFS2 program by EPA. However, EPA is currently reviewing the specifications of the program in light of the lack of investment in capacity to produce advanced biofuels.[4] The EPA has delayed its decision until year's end.

There is also uncertainty in the minds of investors which brings in doubt about the success of these other policies. For example, investors are wary of the government's resolve to continue fuel subsidies for various biofuels. Congress has already allowed the subsidy for biodiesel to lapse, which has resulted in the shutdown of existing biodiesel capacity. The subsidy for ethanol will also be up for renewal. Investors are wary of investing in biofuel projects whose success is dependent upon government subsidies when government actions have sent conflicting signals. Ignoring the risks associated with the availability of these biofuels by assuming that these fuels are readily available to meet the policies assumed in the reference cases as well as a regional LCFS policy again understates the uncertainty and costs of an LCFS policy. At least some of the scenarios examined should reflect an outcome where base case policies are not fully successful.

E85 Fuel Prices too low

The blend of E85 used in the EIA forecast likely contains little cellulosic ethanol. Therefore, if one were to account for the cellulosic ethanol used in the different scenarios, the cost of E85 would exceed gasoline. Therefore, the assumed price for E85 appears too low relative to gasoline.

Having said this, we recognize that the future price of ethanol is quite uncertain. Cellulosic ethanol is still undergoing process development, thus the costs to produce this biofuel are dependent upon the degree, the pace of technology improvement, and the success of commercial scale up. Also, the cost to produce lower emitting blends of ethanol involving conventional crops is also uncertain. Therefore, it is only reasonable that a sensitivity analysis should be performed that considers a wide range of prices for cellulosic E85 and conventional E85.

Failing to consider scenarios using a range of ethanol prices also leads to a lack of sensitivity in VMT values. By assuming the cost of ethanol is the same as gasoline on a gasoline gallon equivalent basis implies that the VMT will be virtually invariant between the scenarios and the baseline because the equation to adjust VMT, which relies on the percent change in fuel prices, will result in no adjustment.

Location of new ethanol plants

Based on recent history, the state's analysis seems unbalanced in its assumptions about where new ethanol production facilities will be constructed. In seven of the eight scenarios, the state assumes all new ethanol production facilities needed to meet the state's LCFS would be built in Oregon. With major production facilities recently built in Idaho and Washington, it seems that the probability of these facilities being expanded and new facilities being built outside the state rather than inside is much greater than one in eight.

Carbon Intensity Factors

The choice of values for emission factors can significantly affect the results of the analysis, and many uncertainties arise in selecting the right values to use. With biofuels, the life-cycle emissions of individual biofuels include both direct and indirect impacts. Determining direct emission can be challenging. Furthermore, accurately determining the indirect effects is highly uncertain and a subject for future research. As a result, the range of potential emission factors for a given biofuel can be quite large. Evidence of this is cellulosic ethanol and the range of estimates provided by EPA. Scenario design needs to recognize this uncertainty in the construction of the scenarios and allow for realistic optimistic and pessimistic scenarios.

Scenario D implies extremely **high** PHEV penetration

Scenario D seems to assume an unrealistic level of penetration of PHEVs. We built a spreadsheet model to estimate the penetration rate of PHEVs in terms of share of new vehicles sales in 2022. This vehicle turnover model estimates the size of the vehicle stock in each year by starting with the vehicle stock in the previous year and adding to this value new vehicle sales and subtracting off vehicle retirements.

To compute the penetration rates, we assume the scrappage rate and growth rate of the stock of vehicles is time invariant.

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4 Facilities are expected to turn out up to 25.5 million gallons this year of cellulosic ethanol—far below the 250 million gallons that the U.S. Environmental Protection Agency (EPA) once wanted fuel makers to produce.

We adjusted the vehicle penetration rate of PHEVs over time to hit the Scenario D target for the stock of PHEVs in 2022. The growth and scrappage rates combine to determine the evolution of the vehicle stock. For the penetration rate, we attempt to represent the classic s-shaped curve while also inputting realistic ramp rates where possible. This would require that over 30% of new vehicles sold in Oregon in 2022 are PHEVs. This incredible penetration rate in terms of new vehicle sales would exceed all historical penetration rates for new vehicle technologies.

Scenario D suffers from an additional problem. The amount of change in the electric sector infrastructure to handle the great number of electric vehicles would likely be technologically infeasible without large costs. A study produced for the ISO/RTO Council in conjunction with Taratec suggests that a total of 1.5 million plug-in electric vehicles **nationwide** would be feasible in 2019 and 2.25 million would be optimistic. Scenario D suggests that Oregon would account for about 10% of new PHEV sales; whereas Oregon currently accounts for about 1% of all new vehicle sales.[5]

The highly questionable feasibility of the PHEV assumption for scenario D suggests that scenario should be modified to consider a much lower penetration of PHEVs.

Questions:

Are the price increases in food and food products due to competition between food and fuel production through agricultural production captured?

The cost of living will increase as ethanol production drives up the demand for agricultural products in Oregon. This will put pressure on food prices as well. The labor and capital cost would also increase and these increases will translate into higher production costs in Oregon. Are all these effects captured in the modeling?

Furthermore, assuming the price of imports from other states remains constant, Oregon would import more, which will offset the increase in GSP through a reduction in net exports or an increase in net imports. Is this effect captured?

In the reference case, it appears that ethanol and gasoline prices are basically the same on a gasoline gallons equivalent basis. Since the incremental cost of flexible fuel vehicles is between $275 and $450 more than gasoline powered vehicles,[6] is there not a loss in consumer welfare because now consumers must pay more for each mile travelled? Does this loss show up in the calculations of personal income or any of the other economic measures? If not, then the analysis is not accounting for all costs?

Comparing the fuel price tables in Lawrence's October 19th memo, we do not understand why biodiesel prices are correlated with diesel prices, but E85 prices are not correlated with gasoline prices. Is there a reason for this difference in correlation patterns?

We could not find any discussion as to what entities provided the investment for the new commercial infrastructure (e.g., upgrades to petroleum terminals, delivery system for E85, new ethanol plants, charging and CNG stations, etc.) required for alternative fuels and vehicles. Who funds these new infrastructure projects? Also, what activities are forgone so that these new investments can take place (i.e., which sectors suffer losses because investment is being diverted to alternative fuel infrastructure)?

Where are the costs and resource requirements of implementing an LCFS program, such as rigorous compliance monitoring and enforcement by Oregon state agencies, factored into the analysis? Without focus on compliance and monitoring the outcomes of the program will be unknown and the overall benefit of the effort unclear, if in fact, achieved.

The description of Business-as-Usual notes a biodiesel blend level of 13.5% in 2022 due to the federal RFS-2, and this is used in modeling to effectively reduce the amount of biodiesel needed in the LCFS scenarios. Given that equipment and engine manufacturers do not endorse the use of higher than B5 and rarely, B10, this level of biodiesel use represents technology challenges for equipment manufacturers and warranty concerns for the predominantly heavy duty diesel fleet. Has forward looking acceptance of B13.5 been indicated by key global OEMs (original equipment manufacturers)?

The chart depicting the biofuel volumes used in compliance scenarios in 2022 (DEQ website, Oct 14th meeting files) prompts a number of questions:

- The BAU, BAU High Oil Prices and BAU Low Oil Prices differ only in the displacement of Sugar Cane Ethanol with Wheat Straw Ethanol; all other volumes of corn ethanol, cellulosic etc remain unchanged. This doesn't seem logical as higher oil prices would be expected to promote increased cellulosic production due to enhanced profitability of this new sector.
- Scenario C, F and G - Mixed biofuels without ILUC, without ILUC High Oil prices and without ILUC Low Oil prices also have identical fuel compositions in these scenarios. The impact of oil pricing on increased cellulosic production is not included.
- Scenarios A-G have a fixed quantity of Oregon Waste Biomass Ethanol regardless of inclusion of ILUC or oil pricing, implying that this product will be a lower ethanol stream than Brazilian sugar cane ethanol under all scenarios. On what basis is this assumption made? What in-state economic tariffs or other structure will be in place to make Oregon Waste Biomass Ethanol the lowest cost option for compliance as these scenarios depict? The August 10[lf1] Compliance Scenario Analysis slide 27 notes an Oregon Waste Food supply of 1.5 MGY (Summit Natural Energy), yet the 2022 depiction has Oregon Waste Biomass Ethanol at close to 200 MGY, is this realistic?
- What pricing assumptions for sugar cane ethanol have made them such a low proportion of both BAU and scenarios despite their ready availability and carbon intensity benefits?

"Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems," ISO/RTO Council and Taratec, {2010).
Wind, Cory-Ann, Memo on "incremental Vehicle Costs," October 19, 2010.

VMT Sensitivity to Fuel Prices

We are confused how the modeler's VMT sensitivity to fuel prices was applied. The October 19lh memo from Michael F. Lawrence of Jack Faucett Associates (JFA) states: "The analysis of Oregon's low-carbon fuel standard pathways retained an elasticity formula already built into Vision. This elasticity formula assumes an elasticity factor of-0.1, meaning that a 1% change in the fuel price encountered results in a -0.1% change in VMT driven."[7]

Scenarios C, F, and G have very different fuel costs, but they consume exactly the same total volume of fuels as stated in table 29 of Jennifer Pont's October 18 memo.[8] Since this table's numbers are on a gasoline gallon equivalent basis, this equivalence implies that these scenarios have the same level of VMT. This result seems to directly contradict the claim that VMT was adjusted according to changes in fuel prices.

In Scenario G, which has the highest fuel prices relative to gasoline prices, presumably should have lower VMT than scenarios F and C. Is this true, and did the model account for the loss in consumer welfare from traveling less? My suspicion is that the model did not account for this loss. Furthermore, scenario G confounds the impacts of the prices by also lowering the carbon intensities for biofuels and allowing an increase in the blend wall. This reduction offsets the impact of the fuel prices so one cannot understand the full impact of gasoline prices being below biofuel prices.

Conclusions

The linking of the VISION and REMI models is not internally inconsistent. The REMI model fails to fully account for the economic impact of investment decisions. The flawed modeling approach means that the reported economic impacts of the LCFS are erroneous and misleading.

The design of the baseline and scenarios biases the analysis and understates the costs of a regional LCFS policy. The design of the cases ignores a number of important issues and as a result assumes greater flexibility and lower costs to comply with an LCFS than actually exists.

The design of the scenarios creates the image that policymakers only need to decide between low cost biofuels and no additional cost electric vehicles on a life cycle basis. Important issues such as fuel infrastructure constraints (e.g., blend wall constraints on the use of biofuels and electricity grid upgrades), consumer resistance to purchasing new higher cost vehicles are washed away by the convenient choice of assumptions.

The true issue should be how much more of a GHG reduction benefit will such a program deliver over what is projected to be accomplished by federal and state programs already in place, and at what additional cost. The Federal RFS2 program will deliver GHG benefits federally, Oregon states concern that their fair share of the RFS2 will not be realized in state is an unrealistic basis on which to base an LCFS program of this complexity and cost, and the financial analysis provided fails to represent the true cost-benefit analysis on this basis.

Failing to present a realistic "worst case" economic scenario as part of this analysis only serves to reinforce the erroneous conclusions pointed out above.

Thus the Oregon study, as currently formulated, is not defensible as its results rest upon an inappropriate model structure and restricted set of input assumptions and scenarios. It will provide policymakers with a one sided and unrealistic view of the consequences of an LCFS policy.

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- How are out of state and in-state fuel production assumptions made? ***Response:*** *We created the compliance scenarios to set the bounds of maximizing the number of ways that people could comply with the program, and we tried to keep those scenarios realistic.*
- How proprietary is the conversion tool to translate REMI inputs? Is it a transparent process that produces outputs that the committee can review? ***Response:*** *(JFA) It's not proprietary at all. The VISION model produces changes in the vehicle fleet, so it tells us over time how vehicle fleet technology will be changing, which then needs to be converted into the right kind of dollars for the REMI model to take in as changes to the baseline.*
- I just want to make sure that the report has enough description of the inputs and outputs for readers to conduct a critical analysis of the information and understand the range of what could be expected out of

7 Lawrence, Michael, "Memo: Basic Data Assumptions in Response to Requests Made at October 14 Meeting," October 19th, 2010.
8 Pont, Jennifer, "LCFS Scenarios Infrastructure Costs," October 18th, 2010.

that translation. ***Response:*** *There are assumptions for example such as a vehicle price today and in the future, and all of those will be in the report.*

- In terms of population growth, are the projected numbers both in terms of the way the population itself is growing or are you looking at it relative to changes in the rest of the country? ***Response:*** *(JFA) It is both internal population growth from the existing population in Oregon and it also includes migration out of and into the state. So it is a population forecast from now until 2022 and the REMI model is a national model and can be broken down into various sub-regions, groups of states, individual states and the county level. What the REMI output tells us is that the Oregon population will be a bigger proportion of the national population in 2022 than it is now.*
- I am curious about the forecast that energy use (in Oregon) will grow by a third; is the per capita energy consumption flat? ***Response:*** *(JFA) Energy consumption is growing less rapidly than state product and we are becoming more efficient over time at consuming energy. With regard to output per unit of energy, if we look at history over the last 30 years, that has been the period in which the most dramatic change in our economy has occurred, associated with efficiency in energy use. The costs of energy and worries about scarcity have changed the way we think. Part of that is driven by the market, part is driven by federal and state regulation, but we use energy much more efficiently today than we did 35 years ago when we had our first energy crisis. In theory there may be a limit to efficiency, but at present we are still improving energy efficiency.*
- I realize that maybe energy use per capita is an inexact measurement because you could say on the one hand that if you aren't reducing energy use per capita then you're not doing much in the way of conservation, but on the other hand you could say that there could be ways that individual productivity is going up faster than energy use per capita. ***Response:*** *(JFA) Individual economic productivity goes up over time. Between now and 2022, productivity will increase which will make the output per capita go up. That essentially is where all the wealth comes from, from being more productive in what we do. If we didn't have productivity increasing, we'd just be going along at the same pace.*
- We're saying energy consumption will grow by a third over twelve years with a population growth of 33%- is this reasonable? ***Response:*** *(Pacificorp) Yes that is a reasonable assumption, given the time period.* ***Response*****:** *I think this is a fundamental point. We either have to compare Scenario H to a modified baseline that also has compliance with RFS2 with out of state production or drop scenario H because its giving a distorted impression that adopting a low carbon fuel standard would cause compliance with the exiting RFS2 to change from what it would be in the baseline. I think what Randy came up with would be the real result of scenario H, that it would show flat, which is definitely worse than all the other scenarios. Which you would assume, if compliance with the LCFS is done primarily through out of state production, we would see no change really from what we're doing today. So I think we need to make one of the two changes mentioned, because we can't leave it like it is.*
- I disagree with Andy on this, specifically that there would be no impact from Scenario H. There is a high probability that if the LCFS isn't implemented in the state, the production won't take place in the state, and that LCFS will also drive up prices significantly to the consumer which will have a negative impact within the other benefits within the other scenarios that show job growth from the construction of production plants . So compliance scenario H should show a significantly larger negative impact to Oregon. ***Response:*** *What we're doing in this scenario is an analysis of the comparison of the business as usual to the scenarios, and the way you just described that was not comparing the business as usual to the scenarios.* What I am saying is that the business as usual compared to the LCFS where the production is not instate but the cost impacts to the state are there. ***Response:*** *But that's not what is causing the dip. What's causing it is that under the business as usual case there is an assumption that some of the compliance with the RFS2 is from in state production, and when you add the LCFS, that causes the*

production that would have been in state to move out of state, and it is not a realistic assumption to assume that the standard, which actually creates an incentive for production of biofuels would cause existing forecasted production to somehow move out of state. That is the implication of comparing scenario H to the business as usual case. They are built on different assumptions, and it is an incorrect comparison that results in this artifact of the model that requires us to either drop it or change the business as usual case. Just like, for example, with the high and low fuel price, we changed the fuel prices in the business as usual case and in the scenarios to be able to see the difference. In the case of scenario H, you've got to change the business as usual case so that it assumes the maximum amount of out of state production for complying the existing RFS2 against the maximum out of state production for complying with the LCFS, and then you'll see in that case very little if any difference.

- What the economic analysis has made clear is how important in-state production is in providing economic benefits of this policy, and I know we went over all these scenarios, but I don't have enough experience to understand why so much in-state production would occur, because the policy as I understand it incents the use but not the production of low carbon fuels. And because production is so critical to the benefits, I question if we have the ability to connect those dots. If production all goes to Washington or Idaho, then we've met our carbon emissions reduction goal, but we haven't seen the economic benefits. It seems like there needs to be a way to incent, through policy, in-state production because it's so important. The incentives that have been in place are now being diminished, and those have been powerful incentives and are less so now, which leads me to ask what confidence are we going to have with regard to the benefits we are seeing? ***Response:*** *The LCFS needs to be neutral on that point, and that is important because fuel is an interstate commerce, and we can't provide extra credit for fuel that is produced in Oregon. It is really important that our policy is neutral with regard to where the fuel is produced. The GREET model is going to provide better credit for fuels transported shorter distances, but that won't distinguish much between fuels produced in Washington and Idaho, but probably from further away you'll see a net carbon penalty from transporting fuel a long distance, but that doesn't mean that it couldn't be sold here. The reason for bracketing the compliance scenarios for the analysis from all in-state to all out of state fuel production is to show you the range of what could happen. Other policies that the Oregon Legislature and others may take to encourage development of low carbon fuels in-state may drive where the production occurs, and having a program that increases demand is going to be necessary for that to happen, but I think they will be separate driving policies. That's why it is so important that we show in Scenario H that the worse-case scenario where none of those things happen and all production is out of state, is neutral, which is the worst-case scenario for the program.*
- If you look at some of recent the reports on ethanol production, once cellulosic ethanol is commercialized, the most economic production facilities are expected in the South. The USDA study says that nearly 50% of production will come from the south, then a significant portion from the Mid-West, and a lesser amount from the Northwest. So some incentive is needed to overcome that differential on the costs side.
- I still have a question regarding Andy's suggestion to change the business as usual in scenario H and not including forecasted in-state production for compliance with RFS2: How is taking any future production of RFS2 capacity that could be forecasted make it a better comparison? ***Response:*** *(JFA) We're saying it the opposite way. You'd want to leave the in-state production alone.* ***Response:*** *What we're saying in scenarios H is that if we had any additional biofuels that need to be produced to comply with the LCFS above and beyond what would otherwise be required to meet the RFS2 or other standards would occur out of state, then I think (the graph for Scenario) H would be flat. But what's happening in (scenario) H is that we're taking production that in the business as usual case was assumed to be in state and moving*

it out of state, and that doesn't make any sense because nothing in the LCFS policy would cause that to happen.

- As far as tracking statewide economic benefits, it seems like all of the scenarios are currently aligned, keeping Oregon dollars in Oregon, so if that's what scenario H can achieve, then it serves a purpose, of determining whether or not we need to change the baseline to do that, but there is some validity to having some version of scenario H, that compares the dollars estimated to stay in Oregon under the other scenarios, and in scenario H dollars associated with production leave the state, which raises the question of where do those dollars go.
- (Chair) Suppose this regulation were not intended to achieve carbon reductions but was intended to foster economic activity in the state, then the worse case (baseline) would be that this regulation is fully ineffective and RFS2 is going to achieve the goals, and the LCFS wouldn't have any positive impact, which would be the flat line on the graph. The best case scenario would be a whole lot of capital investment and the reality might be somewhere in between. So I agree with the bounds created by the scenarios. ***Response:*** *(JFA) REMI thought they were running the same scenario against itself and that wasn't quite the case, so I think that will just need clarification. They just didn't have enough time to get that redone before this presentation. We can reproduce this scenario, and it would show essentially a flat line.* ***Response:*** *We will be fixing that and will revise and repost that graph.*
- Do the electricity prices remain constant in the model? ***Response:*** *(JFA) That's correct, there is no change in the electricity prices in the model.* Where do the fuel prices used in the scenarios come from? ***Response:*** *(JFA) Fuel prices come from the Department of Energy Annual Energy Outlook.*
- In Scenario D, what causes the decrease in heavy duty diesel vehicle use? ***Response:*** *(JFA) Each of the scenarios has a set of alternative technologies on the road in 2022, and this reflects less diesel engines being bought and replaced by other technologies.* And when you say CNG, do you mean CNG and LNG together? ***Response:*** *(JFA) Yes, all natural gas.*
- Is the price of gasoline expected to go up at a different rate than electricity? ***Response:*** *(JFA) I'm not sure about the rates of change, I would need to look those up. Both the gas price and the electricity price come from the EIA.*
- What happens in scenario F where there is a dip and then a rise, and also scenario C – what is going on to cause this? ***Response:*** *(JFA) Change in plant spending over the business as usual level, so it's a variation between how much plant spending occurs.* ***Response:*** *(JFA) I believe the questions was why scenarios other than H have dropped below zero – is that correct?* Yes. We're looking at slide 26 which is the plant spending slide and that slide shows that in scenario E where in 2021 there is lower investment than the baseline. ***Response:*** *(JFA) That's accurate, we received our input and assumptions from TIAX, and those assumptions including in the baseline a certain number of ethanol biodiesel plants and I believe E included more ethanol plants in 2019 but one less biodiesel plant, if I remember correctly. Or it may be the reverse, because the strategy in D had a stronger focus on heavy duty than light duty.* ***Response:*** *And the same thing happens in scenario B, which is a mixed biofuels scenario with indirect land use, with the same kind of explanation?* ***Response:*** *(JFA) Yes, we see that reflected later in the overall costs when you'll see that B has an overall impact that drops below the others in 2021, so this drop will manifest itself again in other slides, and the reason is the number of plants that are anticipated to be constructed.*
- What does aggregate demand tell you that is different than what state product tells you and how you would think about it? ***Response:*** *(JFA) It doesn't tell you anything different in terms of the analysis.* It does tell us how the policy can be attributed to market value within the state? ***Response:*** *(JFA) It tells you as you look across all of the 70 sectors in the REMI model it tells you which sectors are shrinking*

and which are growing relative to the baseline. But in this presentation, it is summed across all of the sectors, so state product stays the same.

- *(JFA) We have changes in energy consumption by year by scenario, and they come from the VISON model. It is not in the text of the report, but can be found in the appendices.*
- Do we have in the appendix the aggregate demand broken down by the 70 sectors? ***Response:*** *(JFA) That is correct. It has the change in output, mostly what you see are zeros in the matrices because the change is very small. In order to see the change in those sectors you have to look where there are significant changes such as petroleum or agriculture. There are no negative numbers because the market is larger in the future than it is now, so it is a relative change from the baseline. The input output model which is a piece of the REMI model called the technical coefficients is the measurement of the inputs required to produce the desired degree of outputs. If the change in output of the product the technical coefficient then measures the amount of that input that's required.*
- One of the problems we talked about previously is the unique situation that none of the petroleum used in Oregon is produced in the state, so the negative economic impacts that would fall out from an LCFS would be felt in Washington and other states. That is a big gap in this analysis from WSPA's opinion, in that you're only looking at a small window of the overall impacts. ***Response:*** *At one point we talked about whether we could look at the conclusions of Washington's economic analysis and somehow make some comparisons. Washington used a 15% blendwall where we used a 10% blendwall, and they had different assumptions about land use, so it would be interesting to compare our scenarios and analysis to theirs with regard to petroleum production in Washington. Can we get Washington's results and somehow compare their results to the results of our analysis?* ***Response: (Mike, JFA****) I don't know the specifics, but we can look that up.*
- The scenarios were very narrow and the Washington inputs in to the REMI model were almost identical to the Oregon inputs because TIAX was also their consultant, so the input generation work was the same and in general the oil industry doesn't think the projections used are realistic and we feel that the cost of implementing an LCFS program will be a lot higher than what is being modeled in the compliance scenarios, and that isn't reflected in the overall program. I don't think that the REMI work that I've seen from Washington is as complete as the work that is being presented here today. The Washington work just shows the final outputs, which is very difficult to understand how they came to the conclusions they reached. ***Response:*** *(Chair) So for example, you don't know if there is a change from baseline in the Washington model in refinery jobs.* ***Response:*** *I think we should try and get that if possible. I don't know whether it becomes a comparison in this report or if we just try and summarize Washington's approach found, but I think we need to see that.*
- I want to reiterate so that we all understand- would scenario H be corrected in terms of the capital investment costs related to the production plant issue, and as a result prices go up, and as all export there will still be a small negativejust not anything to this scale. So it's not completely neutral, but it's very small. ***Response:*** *(JFA) If the price of alternative fuel which is imported is higher than the price of petroleum fuel that would have been imported, then households will either spend additional dollars to purchase their fuel or they will drive less, and that will result in some negative impact.* Is that the case though? Is the imported fuel price differential as you suggested there? ***Response:*** *(JFA) It is not. Right now the US Department of Energy forecast show those energy equivalent bases the price of ethanol gasoline to be equivalent.* ***Response:*** *Because this analysis is looking at the differential between base case and the scenarios, when you have a high fuel price that goes both into the base case and into the scenario, so that even though petroleum costs more the biofuels are also going to cost more as well because of the petroleum input costs, so the relative difference stays similar and therefore the scenario differences are similar but if you look at the absolute impacts of high fuels prices you would see a bigger*

impact, right? So is a fair way to look at them to say that there isn't much difference between them? ***Response:*** *(JFA) Yes, you could look at it that way. The higher fuel prices change the amount of activity. Up until the recent financial crisis, there has been no bigger driver of our economic downturns than increases in fuel prices. If you look at the history of economic cycles in the United States, you will find very consistent increases in energy prices leading into recessions and slowdowns in the economy. The economy is very sensitive to energy prices, and that should be expected.*

- This is one of the shortcomings that this analysis is showing because you're not looking at a baseline with the normal projections and then comparing with a higher fuel price. You're inflating both of them, and you're not getting the true impact on the economy. It would be more realistic to look at the business as usual price under your standard scenarios and then compare that to a higher fuel price driven by an LCFS. I know we talked about this at the last meeting, that there are no other scenarios that DEQ wants or can afford to run, but I think what's missing here is the impact to the Oregon's citizens. ***Response:*** *It sounds like you're not necessarily following what's in this scenario. It's not a higher fuel price driven by the LCFS, it's an assumption that crude oil prices are higher. And that wouldn't be driven by LCFS, that's driven by other factors. The question at hand is how does a world with higher crude oil prices react to an LCFS, versus a work with lower crude oil prices react, and that's why you have to put the change in the base, otherwise you'd be making some assumptions about how the LCFS would affect crude oil prices.* I guess I misstated my position. The alternative scenarios that I was talking about is when you have your business as usual pricing and compare that to a high price because of the LCFS. That is probably more realistic in terms of impact on the state of Oregon than anything being shown in this analysis.
- It's like Scenario H where the fuel price goes up? ***Response:*** *(WSPA) We're building a picture here where we're assuming plenty of fuel will be available, which I think is a big questions that we aren't addressing here. We're saying we're going to build these plants in the state of Oregon, and there's a big question around that assumption as well. And then on top of that, you're assuming that the price of the alternative fuels are going to be at or below the price of gasoline, which we do not believe to be an accurate assumption. So you're building rosy assumption on top of rosy assumption, and coming out with results that contain the inference you've put in there. I can't argue with the results that Mike is presenting here today, but I can argue with the assumptions that went into the analysis and whether they are realistic, when comparing the results of this analysis to other sources of research that suggest a very different outcome.* ***Response:*** *I think what I hear you saying is if the LCFS drives demand high enough for alternative fuels that are not available, then the price of alternative fuels will go up above what the Energy Information Administration's projections are for crisis, then that could change the scenario. Is that correct?* ***Response:*** *(WSPA) Yes, that's one component, So if there was a fuel availability question, then the price question, and in-state job development that are all on the rosy side in the scenarios being analyzed.* ***Response:*** *In-state we've bracketed that, but in terms of price and supply, they are interconnected and therefore really the same thing. So under your scenario, there's a shortage of low carbon fuels and because we have this requirement for low carbon fuels, the fuel providers have to buy it anyway, and their buying it (out of state) at higher prices than were predicted.* ***Response:*** *(WSPA) And then you have to factor in the carbon intensity question, and it doesn't look like corn-based ethanol is going to address the carbon intensity requirements, and cellulosic ethanol is not yet commercialized on a national level, so you're driving that limited supply significantly higher in cost perspective because of that, not even including the cost of production of that alternative fuel, which is still a lot higher than what this is showing. And on top of that, you're saying that the production plants will be built here, which I don't think is a realistic assumption. So as you roll this thing out, it is going to look ten times as rosy to the layman than I think reality will show them.* ***Response:*** *So your quibble is not so much with the economic analysis itself, but more with DEQ's projections regarding availability of alternative fuels that*

*informed the compliance scenarios. **Response:** (WSPA) Or at least bracketing it with looking at a reality scenario that is the way I just described. That would give you your lower bound, which we don't see here. **Response:** One point I'd like you to consider is that we have designed this program so that that scenario can never happen because of our deferrals and consumer cost safety net. So if we had a program that had an absolute mandate regardless of supply, then I think your scenario could be considered the worst-case scenario if it were to come true- if the supply were not available we would defer the requirements , so its built into the scenario that that can't actually happen. **Response:** (WSPA) That still causes negative impacts, because if you're talking about that last discussion that isn't going to happen. Because those off-ramps are in there, but they won't be triggered until a year's worth of data (for the consumer cost safety net) can be analyzed, and from the stranded investment perspective, as a regulated party, we're going to have to start investing a lot sooner than what is being shown here in order to comply, because you have to put all the infrastructure and everything else in place. And then if you shut it off, all that money is wasted. So there significant complexity that we all recognize, but there are also significant costs that I don't think we are accurately addressing.*

- I think you're view of the status quo is pretty rosy. Increased demands for fuel worldwide are now competing with our needs. And for you to say the LCFS is going to create costs, I look at it and see more consumer choice and supply options. And with increased domestic consumption, you're not sending money for transportation fuels overseas, so I just don't see how more fuel availability would not support lower fuel prices across the board. For petroleum, I see it actually benefiting from an LCFS, because you have more options. I can sell biomethane much cheaper than gas. ***Response:** (WSPA) I can't argue with you on that. What I'm saying is that those alternatives are out there, if they are truly economic, they are going to happen with or without and LCFS. An LCFS just adds a lot of complexity, drives a lot of costs unnecessarily, and doesn't need to be put in place.* I would whole-heartedly disagree because of the monopoly position the petroleum industry is in. ***Response:** (WSPA) And for the carbon intensity part of the question, you're not driving it necessarily to other parts of the country, what you're doing is driving the demand to be supplied with Brazilian ethanol. **Response:** (Chair) Some of this is getting into policy stuff, but is there anything more we need to discuss in order for Michael to finalize the economic analysis? It sounds like as a whole the committee has been okay with the way the scenarios have been run. I think some of these points about potential consumer costs are at the margins when the largest impact is seems still revolve around whether production plants are built in-state. You will have an opportunity both in the appendices and additional comments to say, even if you're not disagreeing with the economic analysis work, that you have some differences with how the scenarios were put together or about the inputs.*

- (On the phone: Paul Bernstein, CRA) I'm having trouble with the analysis overall and the sign of the economic impacts. Can you explain why, when you constrain the economy with a LCFS standard, how that leads to economic growth in the state? If I understood you correctly, part of the argument is that you get investment coming into the state from out of state, and that helps the Oregon economy. But there also seems to be something on the consumer side, and I don't get that piece. ***Response:** (JFA) When we look at economic or environmental or labor regulation, what we normally expect is a cost to be imposed on the economy and the benefits are much more difficult to measure in that they come in the form of prevented health effects of avoided loss or injury, so it's always a challenge when conducting a regulatory economic analysis to measure the benefits side, in this particular case, the LCFS will provide benefits of reducing carbon emissions in the state of Oregon, but trying to measure the benefits of that change is extremely difficult, and that may be why that has not been addressed by this panel. But the normal path to analyzing the benefits would include identifying what those benefits are, determining how to measure and quantify those benefits, and take those things that aren't quantifiable and make them as quantifiable as we can.* Are you saying that the model shows what would happen if the U.S. as a whole adopted an LCFS, would you show that GDP goes down in the U.S. if there is no foreign investment into the U.S., or would GDP still increase if the nation adopted an LCFS. ***Response:*** *(JFA) That's a different question that has been addressed by your firm, Paul. In your assumptions the supply of fuel would not be available to meet the national LCFS.* Even if it were, if this is good, then why aren't consumers and businesses doing it now. Because it seems like there is some much money on the table, if I look at your analysis, is the assumption that there are so many market failures? From a common sense standpoint, I'm not arguing against trying to reduce carbon emissions, I'm just looking at this from the perspective of a cost-benefit analysis, and it's hard for me to understand as we get the benefit of reduced emissions how that comes without any costs. To my question about a U.S. level policy, I understand if you can induce investment from outside of Oregon into the state of Oregon, that's a benefit, just like any other type of policy, such as for manufacturing. ***Response:*** *(JFA) That's a good analogy. In this case we're talking about the opportunity for using resources in Oregon to produce low carbon fuels. As for why that doesn't happen on its own, as economists we have faith that the markets will create these opportunities and efficient solutions. We do think that the transportation market has market failure characteristics that are associated with the long term existence of growing supply and the ability of many years of the petroleum industries' ability to provide product at a low cost. One of the things that does is discourage the development and use of alternatives. Imagine the world today if there were no negative externalities associated with petroleum consumption. Carbon is a negative externality associated with petroleum consumption, and the states of California, Washington, Oregon and many others have made the reduction of carbon a primary policy for their governments. And that is that state that Oregon EQC finds itself in today, with the Legislature ordering it to look at this opportunity. And what we're seeing here in Oregon is the Oregon legislature trying to reverse this negative externality to force the technology into place that would have that occur to assure a market that the investors in the alternatives fuels would be able to sell their products, taking away the uncertainty of them being able to sell their products in the market place, which then encourages investment.* ***Response:*** *I think part of the crux of his comment was if in fact over a long enough period of time alternative fuels were cheaper and had other benefits, the market would go towards then without the regulation. And what I had in mind as a response which I would like to check with the committee and Paul on is that there is a certain inertia in our current fuel distribution system that results from the number of tanks, for example, that retailers have then determines how many types of fuel they can supply, the vertical integration of the industry or who owns what resources, but basically who would end up having to pay initially for more access to alternative fuels is sort of a barrier to that happening, even though once those fuels are made there're might be a net benefit to the economy as a whole from having a more diversified fuel supply. So one of my thoughts about having a LCFS is that it helps overcome that market inertia by creating the demand and essentially requiring fuel suppliers to pay for their initial investment in order to make the fuel market more open and overcome that market failure you're talking about.* **Comment:** I'd second that because one of the things Paul said was that this policy would create a constraint, and I think it's just the reverse. It's creating a performance-based incentive to reduce the carbon intensity of our fuels, and the goal would be to spur ways to increase and diversify supply. ***Response:*** *If there are benefits (from LCFS) overall to the economy, it might still be negative on some sectors, particularly for the petroleum sector relative to the business as usual case, and so they wouldn't necessarily have an incentive to make those investments even though it might benefit the economy as a whole. Does that make sense as a way of thinking about this?* (Paul Bernstein, CRA) As you've pointed out, there are a lot of costs associated with changing the system and that's where I question the modeling results. The externality that you mention regarding the emissions is a market failure in itself, but as you said the policy isn't addressing that. But that market failure wouldn't be what's accounting for implementing the policy and seeing positive GDP. Addressing that market failure should be seen in the reduction of CO_2 emission. Again, I still question the sign if the analysis of what you'd find if you used the modeling tool to run a national policy. If you ran a national LCFS and got positive GDP, it just doesn't seem to make sense to me. What makes sense to evaluating whether an LCFS policy is bad or good seems to be ranking it against other policies that reduce emissions and understanding the costs of the other policies, and whether those exceed the benefits of reducing carbon emissions. But again, I have a hard time believing that you would get benefits on the costs side by implementing the policy. ***Response:*** *Your response was with regard to the externalities, but what I was trying to point out was the difference in who benefits and who pays. So if we had the assumption that the diversified fuel supply where some of those fuels were produced in the U.S., was going to provide a net economic benefit including the benefit of the construction of the fuel supplies as well as the benefit of not shipping dollars overseas for imported fuels, the market failure was that those who would have to make the investment to make that happen wouldn't be the ones benefiting, but the benefit would come to others. That could explain the scenario where you have a program that does actually create real economic benefit that wouldn't be adopted by the market without this incentive being created. I didn't hear your response to that thought.* (Paul Bernstein, CRA) I suppose that's possible. But if you think the markets are efficient, then the investment today is going where it gets the greatest return. So again, thinking about the U.S. as a whole, or even Oregon, it makes more sense for investment in Oregon to go to Intel or (electronic) chip manufacturing or something else where there is a competitive advantage and you'd rather import less chips but import more crude oil because overseas they have a competitive advantage in producing crude oil. This is what bothers me about the REMI modeling formulation and the bias of these scenarios, is that it seems to be making the assumption that investment just comes into the economy, and there are many scenarios where it would seem prudent to ask why would people invest in this. They may find that they can get a greater return doing something else. And if you're forcing them to invest in some other market, namely the low carbon fuel that is likely a drag on the economy because without this provision the market has determined that investment ifs better placed elsewhere. ***Response:*** *(JFA) You make a good point, but what we need to keep in mind is the big picture about competitive advantage. What you're suggesting is that the purchase of foreign oil from low cast resources, the production of oil in Saudi Arabia maybe costs six or eight dollars a barrel, and is sold in the market place for forty, sixty, eighty, one hundred, we don't know what it will be sold for tomorrow. Do we have a shortage of petroleum? Are we over the half-way point of having consumed all world oil reserves? We don't know the answers to those questions, but what we do know is that there are substantial economic losses in the U.S. when we import petroleum. One estimate made by the Oakridge (2:44:40) National Lab for 2005, was that if oil prices were thirty five to forty five dollars per barrel, the economic losses in 2005 would range from $150-250 billion dollars. Oil prices in 2005 were considerably higher than that, so the economic losses would have been greater than that estimate and roughly twice that amount in today's dollars. If we could make our trade balance by exporting more product to balance those external flows, we could keep our economy moving forward and I think you would be correct. But the fact is we run a substantial trade deficit a result of our oil consumption, and there are substantial externalities associated with that oil consumption, and changing that mix through government policy can result in reducing those economic losses, which in essence are economic benefits. So it's not clear to me that a national model run would not produce those benefits if we could produce those products domestically to allow transportation and/or to allow collective power production at relatively the same costs as we import petroleum fuel.* I think it is important to consider the scenarios that biofuels production could come from out of state or in other words, the reliance of the policy producing positive GDP impacts on investment from out of state, and if that investment doesn't come in then I would think you'd see a loss in economic output.

- I want to follow up with what Andy said, that has to do with the naiveté that goes into assuming that these markets are open enough that single day commodity price will provide investment into the market.

I think that foundation of an argument for a scenario is ludicrous on its face, given the history of petroleum's role and the distribution and supply. I understand that there are a number of people who believe that markets are quite pure in terms of attracting investment to highest and best or most return, but if you look at any economic analysis completed on the energy efficiency market in Oregon, there are industries with half a billion dollars worth of projects that have a 20% or greater level of return, And so we really have to look at we're setting up and designing this as an incentive to provide assurance to attract capital. And these scenarios point out that if there is this assurance of a growing market share for a particular commodity that there is highly likely to be capital

- If Washington and Idaho and California all adopt an LCFS, what's going to make Oregon be the place where production plants are built? ***Response:*** *(Clean Energy) Why does it always have to be about production plants? What about infrastructure, fueling, etc.?* We've heard today that the biggest economic benefit will be from the construction of those plants. ***Response:*** *(Clean Energy) This is all, in the end, an oversimplification. There are significant amounts of inputs that will occur, and the amount of infrastructure and outlay that my company alone will invest in regardless of whether or not we build a plant for LNG in or out of the state of Oregon, there is going to be a lot of o9perationa expenses, drivers that will be based here in Oregon, like stations. There is a significant amount of capital that goes into fueling stations and there will be significant construction costs. The motivation to locate a production plant in Oregon is that it reduces the transportation costs for moving the final product. I lose carbon benefits when I have to truck fuel from farther away. And there are significant opportunities in the state of Oregon for renewable sources of natural gas, such as landfills and sanitation plants.* ***Response:*** *If Washington and other states also adopted a LCFS, there would be more demand for low carbon fuels, and unless Frank's scenario came true where there wasn't enough capacity to supply it, there's going to be more demand and in all likelihood you'd have plants built in all of the states that would be developed and we do have a scenario where there are no new plants, under scenario H, which I'm assuming it will be adjusted and will show no plus or minus, (2:52:36) which for an environmental regulation is a huge success in that in most cases, when you're trying to address some market externalities there is an actual cost and in this case if you got away with no cost an no benefit, I think you could declare success. And then in all these other scenarios that it's quite possible that there could be significant economic benefit if complementary policies are put into place to draw those plants to Oregon, but in my view if those plants are built in Washington, that's great as well. The bottom line is we're trying to reduce the carbon intensity of fuel and if we can do that without having a negative impact, that's great. Certainly we'd like to see some economic activity in Oregon as well and it's possible with the right complementary programs.*
- This analysis makes it clear what the economic benefits are so it's an easier case to make to legislature to either strengthen the policies we have to encourage companies to develop in Oregon or to develop new policies to say that our economy needs jobs and here's a good way to do it. **Comment from Audience:** (Mike, BP) There has been a lot of discussion of assumptions, which is understandable, but some take the position we might already have enough mandates, with the ethanol mandate and the biodiesel mandates for both Portland and Oregon statewide. With all of those in place, have we seen facts to back up the assumptions being made, for example, increased investment, health of the industry, increased jobs, etc.? ***Response:*** *A piece of the answer to your question is that we already have investment in biofuels being produced in Oregon, and it's largely due to the existing RFS that creates demand for those products. The issue that you'll see in the graphs is that just meeting the current national and state Renewable Fuels Standards is not going to achieve the needed reductions under the LCFS, and meeting the additional requirement of the LCFS, remembering that it is back loaded intentionally to give time for developing new facilities but at some point in 2017 or 2018, more investment is going to be needed to meet it. So theoretically you could also achieve that by strengthening the RFS requirements, but the idea of the*

LCFS is that we're not going to dictate winners or losers, but are going to let them all compete. (Chair) I think it's important to remember that the job given to JFA was fairly narrow and doesn't cover a lot of the discussion we've had about national policies or other ways to get carbon reductions or what the costs and benefits of other programs, and a lot of it does just focus on Oregon, so we aren't looking at costs out of state and it certainly should help inform the Legislature when they look at this program that at least, even as we get a carbon benefit, it looks like our worst case scenario is relatively close to business as usual, and our best case scenario is that Oregon sees some economic benefit from the LCFS. I think JFA has done a great job with limited time and resources, and those who tend to agree with the scenarios and assumptions will say the analysis is good, while those who disagree with the scenarios and assumptions will say this is why we don't think the analysis is very useful. But nonetheless, at least so far I've heard all around that people have recognized the quality of the work the JFA has performed in terms of working through the given assumptions and the inputs, and that's what we hoped for.

Summary of written comments from advisory committee member or alternate December 1, 2010

- With the results of the economic analysis, it is clear the LCFS will be extremely beneficial not only for Oregon's environment, but also for Oregon's economy. The state currently exports over $5 billion every year for transportation fuels. While the LCFS is a performance-based standard, it provides a market incentive for locally produced fuels (while also allowing for low-carbon fuels to continue to flow in from other locations), which will create net jobs, make net improvements for household income, and be beneficial for Oregon's Gross State Product. This is a clear win for Oregon.
- Tiax and Jacket Faucett and Associates have done a good job. They have been thorough and have responded well to inquiries.
- We hope that the economic analysis will be accompanied by a well-written executive summary that clearly lays out highlights of the study, including the benefits the LCFS will bring to Oregon on job creation, household income, Gross State Product, and other relevant measures. The report could be clearer in laying out the compliance scenarios--perhaps with a chart that helps compare and contrast each scenario or at least formatting that will be easier to read if it is text only. The report should also explain that the scenarios were meant to "bracket reality" to help explain why there isn't a "most likely" scenario.
- In the Introduction, explanation of a "performance-based" standard could help describe the LCFS and how it differs from a volumetric blend requirement.
- In general, it would be very helpful to have more interpretive text accompany the graphs. For example, The *Changes in Income under Eight LCFS Compliance Scenarios* could be accompanied by a caption that says, "For 7 out of 8 scenarios, there is a positive net impact on incomes ranging between $100 million and $700 million per year throughout the program timeframe."
- The economic analysis clearly shows positive impacts to the state's economy based upon a robust low carbon fuels industry in Oregon, particularly when low carbon fuels are produced within the state rather than imported from outside the state. While the LCFS establishes a strong incentive policy for investment and new business in Oregon, ZeaChem believes that more can be done to incentivize low carbon fuels within the state. ZeaChem understands that additional programs would likely be implemented outside of the DEQ's authority but can be closely coordinated with DEQ's efforts to implement the LCFS successfully.
- Recommendation: DEQ, along with the State Legislature, Business Oregon, Oregon Department of Energy, Oregon Depatiment of Agriculture, and others, should continue to work closely with vested stakeholders including low carbon fuel producers and feedstock providers to promote low carbon fuels

produced in Oregon. Working together, Oregon can establish itself as a national leader in low carbon fuels production.

IX. Potential Impacts to Public Health and the Environment

Summary of written comments from advisory committee member or alternate December 1, 2010

- The LCFS is part of a larger strategic effort to reduce greenhouse gas emissions. The sooner we reduce emissions, the more cost-effective mitigation efforts will be and the more likely we are to reduce the risk of catastrophic climate impacts. Oregon can serve as an example to the rest of the country and should be commended for its leadership on the LCFS. Policies that reduce emissions help safeguard Oregon's economy, health, and environmental well-being. Every effort should be made to maintain the environmental integrity of this program.

General Comments

November 3, 2009 Advisory Committee Meeting

- Oregon needs to go slowly and consider all of the possible effects before adopting a program that could have such major consequences.
- Oregon should look to Washington state rather than California in considering a LCFS, since most of Oregon's fuel comes from Washington refineries and the effects of a Washington state LCFS on refinery operations in that state will have effects here.
- California is spending hundreds of millions supporting its LCFS program, compared to a few staff positions in Oregon.
- California performed a life cycle analysis of fuels such as ethanol, a position which commenter recalls some Oregon staff seeming to disagree with.
- Committee must consider costs of the program, and of emissions reductions in general.
- Concern that the committee consider its obligation to look farther into the future, considering the impact of avoiding hard questions now;
- A lot of opportunities for wealth creation will accompany the switch to lower carbon fuels.
- The committee should look for opportunities, especially for rural Oregon.
- Committee must consider impacts of new policies on jobs and the existing electric grid.
- Implementation issues need attention, e.g. giving markets time to respond, keeping current economic conditions in mind, consider micro-economic impacts along with macro-economic impacts.

January 27, 2010 Advisory Committee Meeting

- A committee member commented that the LCFS is not focused on discouraging the use of fuel through conservation, nor on reducing vehicle emissions. Rather the LCFS is focused solely on lifecycle emissions from fuels. Another committee member noted that efforts are underway by groups in the state to address those other issues, and suggested that the advisory committee voice support for efforts to reduce vehicle emissions and vehicle miles travelled. Chair Reeve suggested that the decisions about which greenhouse gas reduction programs to pursue belong to the Legislature, and that the committee's focus should be making recommendations for a state LCFS. However, he supports giving individual committee members the opportunity to include comments about policy issues and other concerns in the committee's final report to the Environmental Quality Commission.

Summary of written comments from advisory committee member or alternate November 30, 2010

- The committee process was well-run and provided an excellent vehicle for raising and airing issues about compliance and implementation. The LCFS is a powerful tool for reaching greenhouse gas emissions goals and will work well in Oregon.
- DEQ did an excellent job managing and staffing the committee, and the implementation of the LCFS will certainly benefit from the hard work of all those involved.

Summary of written comments from advisory committee member or alternate December 1, 2010

- We would like to commend the Department of Environmental Quality (DEQ) for a well-run process that has given all stakeholders—and especially impacted sectors—ample opportunity to provide input on all facets of the program. At every step of the process, DEQ has evaluated how to make the LCFS administratively straightforward for both industry and the agency. DEQ has been thoughtful in preparation of materials and extended the timeframe for the Advisory Committee to run through 2010.
- DEQ prepared a comprehensive and streamlined draft report for review. The Low-Carbon Fuel Standard is an important policy for Oregon's long-term environmental and economic health. We look forward to continued participation in the process to develop Oregon's LCFS and its adoption by the Environmental Quality Commission.
- We feel that when implemented the LCFS will be a productive policy too to both spur fuel innovation, economic development and lower carbon emissions in the transportation sector.
- We feel that Staff led a very professional open and effective stakeholder process.
- Global warming is the most pressing global issue facing this generation. At every level we will need a systematic and strategic approach to meet this challenge.
- Transportation represents roughly one-third of America's and Oregon's global warming pollution. In order to reducing pollution from the transportation sector, we will need to build move livable communities and reduce the number of miles traveled by vehicle, make cars and trucks go farther on a gallon of gasoline, and use fuels that emit less global warming pollution.
- In 2009, the Oregon legislature adopted and the governor signed House Bill 2186 which provided the authority to the Oregon Department of Environmental Quality ("DEQ") to create a low carbon fuel standard ("LCFS"). The LCFS requires fuels to be 10 percent less carbon intensive by 2020 in comparison to 2010 levels. In drafting the low carbon fuel standard, the Oregon Department of Environmental Quality sought and gained an enormous level of input from key stakeholders. Given this high level of input, Environment Oregon strongly supports the Environmental Quality Commission adopting the LCFS in 2011.
- The work of DEQ's staff has been tremendous to get us to this stage. The LCFS will be an integral component in reducing global warming pollution from the transportation sector and meeting Oregon's climate challenge. In addition, as a market-based regulatory approach, it effectively internalizes the

environmental and social costs of global warming while encouraging the growth of Oregon businesses that specialize in producing and distributing homegrown clean fuels and cars.

- The Department of Environmental Quality is to be commended for its professionalism, competence and willingness to work with a wide range of interests at the table that composed the LCFS Advisory Committee this past year.
- Oregon has taken a leadership role in addressing the opportunity for low carbon fuels in the state. Significant work by DEQ has gone into crafting this draft report. Overall, ZeaChem believes the recommendations made by DEQ in the report will encourage the production and consumption of advanced biofuels in Oregon with associated investment and job creation benefits.
- The blending of ethanol into the gasoline fuel pool is regulated at both the state and federal levels. current blending for the general vehicle fleet is limited to 10% ethanol by the U.S. EPA as well as by the state of Oregon. As the draft report and appendices correctly recognize, the EIO blend wall is projected to be reached in 2013, meaning that no more ethanol will be allowed to be blended into gasoline. This limit creates a significant barrier for the entry of advanced, cellulosic ethanol into the market.
- Recommendation: In order for Oregon to equally promote the production of all available low carbon fuels, including ethanol, the EIO blending limit needs to be raised. The U.S. EPA is making progress to raise the blend level to 15% (EI5). Because Oregon has separate policies in place limiting ethanol blending to 10% (see: ORS 646.913, ORS 646.957, and OAR 603-027-0420) ZeaChem encourages DEQ to include in its draft report a specific recommendation to amend state policies regarding ethanol blending. Such a modification will align Oregon with federal policy and encourage the production of advanced, cellulosic ethanol in the state.
- The Department of Environmental Quality is to be commended for its professionalism, competence and willingness to work with a wide range of interests at the table that composed the LCFS Advisory Committee this past year.

Public Comment at Advisory Committee Meetings

- **November 3, 2009 Advisory Committee Meeting**
- **Dwight Stevenson of Tesoro:** Expressed concern about the complexity of a LCFS program. He also noted the potential for unintended consequences, citing the example of California's reformulated gasoline requirement that initially led to the use of methyl tertiary butyl ether or MTBE. MTBE was later found to cause water contamination when leaked from underground tanks. In the third phase of the reformulated gasoline program, the reformulation caused increased permeation [i.e., more fuel evaporating through fuel lines and contributing to smog].

December 3, 2009 Advisory Committee Meeting

- **Ralph Moran, BP America:** BP continues to think it's important for the advisory committee to discuss the purpose of the LCFS and what the alternatives are, which would be consistent with the process going on in Washington and he thinks also consistent with HB 2186. He thinks the committee needs to discuss whether the objective is GHG reductions or fuel innovations. If a national carbon reduction program is enacted, the incremental GHG reduction impact of the LCFS will be zero. BP worked with CARB in putting together the California LCFS, and believes the advisory committee has heard only one side of the story from CARB, but needs to hear other sides to the story. BP has big concerns with California's LCFS design – some of those design flaws could be fixed, and others are inherent to the LCFS. They think it's important that the committee hear a presentation from BP, with opportunity for back-and-forth between the presenter and the committee.

- **Dwight Stevenson, Tesoro:** He thinks it would be helpful to draw a diagram of what the committee is envisioning, for instance where in the process a credit is generated, to make it easier to understand. Other indirect emissions that haven't been considered by CARB thus far are those due to increased farming intensity, using more water and fertilizer, which could occur due to increased demand for biofuel crops. CARB's expert workgroup will look at this issue. The committee should consider whether to set separate baselines for gasoline and diesel, since diesel has lower carbon intensity and increased use of diesel could contribute to GHG reductions. The economic analysis needs to consider the technological feasibility of producing the fuels that will be necessary – he didn't see plans for an adequate technological analysis in the presentation this morning. If alternative fuels aren't currently being produced, perhaps they are not economically competitive, contrary to CARB's economic analysis. CARB assumed a cost for ethanol in their economic analysis, but this was not based upon an engineering analysis, and the assumptions are overly optimistic.

April 15, 2010 Advisory Committee Meeting

- **Angus Duncan, Global Warming Commission:** With regard to carbon content of those miles that are going to driven by electric vehicles, even if it is plugged in at night and even if you did not assume that it was being met by the marginal gas instead of the coal. At some level we have to assume that there is going to be substantial electric vehicle market penetration and therefore needed additional base load. But pretty much every analysis that I have seen, government and interest group, has been pretty clear that if you plug your electric vehicle into a wall socket in your garage and it is fed with electricity from a pulverized coal plant, that you are still on a carbon basis but it is substantially less carbon intensive when you get in that car and drive it. Yes, you are technically driving coal generated electricity, but you are displacing another fossil fuel, another hydrocarbon, gasoline, and the efficiencies of a single large coal plant are so much greater even after allowing loses from transmitting from Wyoming to Portland, Oregon and putting it into an electric vehicle that there is a significant carbon savings to doing that, assuming the worst coal based resource case. And if we assume that increasingly as coal plants are retired and are replaced by base load gas plants that carbon benefit increases proportionately, so electric vehicles are a very significant carbon reduction mechanism even given the existing resource configuration in the country, let alone in the Pacific Northwest. Secondly this question of how intermittent resources interact with the system. Because there is a tendency to think one dimensionally, that if you put a wind project on the system and you have to have electricity when someone flicks the light that you need a dispatchable resource, gas or coal, immediately behind it and you have to match it megawatt for megawatt. If you really push it to the extreme and that back-up megawatt needs to either be running or it can be ramped up in seconds because the wind could die off in seconds. As a practical matter, that is just not how the system works. The system calculates its reserve obligations while looking at a whole range of resources, not just any one source and it also looks at the diversity among the resources. It looks at the consequences if one wind trimming was banned, which is 1-400 megawatt coal plant or 1-1,100 megawatt nuclear plant on an un-scheduled outage. It has to calculate how much reserve is needed for a variety of different scenarios not just one involving wind and wind dropping off almost instantaneously. Even if we were looking at that, we would also have to look at the regional resource diversity underlying that wind resource. Because you can have the wind dying off in a project over here and the wind coming up on a project over there, you can decide if you are going to look at it on a seasonal basis, or an hourly basis or a minute-to-minute basis. We get different calculations in each one of those cases and I could really belabor this and get tedious, but I promise you I will not. The only other point that I wanted to make was that when we started the project that I am still involved in called The Regional Wind Integration Project, which is chaired by Bonneville and the power council. Pretty much all the utilities in the region participate in that and a few riff-raff members like me. We look at a number of different things. We looked at what the existing system would accommodate by way of new penetration, what kind of tweaks you could do to the systems to up that before you had to add any new resources whatsoever. In addition, then you looked at what the range of new resources might be, storage and demand side and generation that could add to the system flexibility. Long story short, I think Bonneville and the utilities were pretty nervous about anything assuming 10% wind penetration. The Bonneville system is already up between 15-20% and they are operating without having to add any new flexibility. They have tweaked the system. They have expanded some of the balance in authority in the connections that are compared to that. There is at least one study from the upper Midwest that suggests that you could get as much as 30-35% wind penetration or wind and solar intermittent penetration before you had to start adding new reserve capacity. So there is a lot of flexibility still in the system and frankly, electric vehicles testing that system make me a lot less nervous that the potential that we will be shutting down a very substantial amount of the coal fuel in the next 20 years. One of the resources that we looked at in that integration project, and it is in the report, that is a potential significant contributor to adding flexibility into the system is plug-in electric hybrid vehicles. So, while they may test the demands and capacity back to the system, because of their storage capability, they may also add significant capacity to the system. And they may add at the wind, similar to that in Wyoming where it has to come over through wires, but right here in downtown Portland. So it's a more complicated subject than obviously you have time to get into here, but I think issues of electrical system capacity being able to accommodate even George's most ambitious projections is an issue that we have to deal with, but it is an eminently manageable issue at this stage.

June 23, 2010 Advisory Committee Meeting

- **Todd Campbell from Clean Energy:** Regarding the horizon that you are considering for the overall low carbon fuel standard. Ideally we would love to see a 2020 timeframe, because as soon as the program starts we can start expanding our penetration and developing infrastructure to support the low carbon fuel standard, as well start generating credits, which we think are a wholly valuable commodity down the road. I also wanted to express that the further we push out the horizon delays really being able to invest more heavily in ultra low carbon fuel, such as biomethane in the region, because we actually do account, to some degree, for credit generation of what would be derived from the program to be able to bring ultra low carbon fuels, like biomethane into the market. We certainly would be supportive of a 2020 or a 2022 time frame, but we would be happier with a 2020, because we would like to be able to expand our growth sooner rather than later.
- **Angus Duncan, Chairman of the Oregon Global Warming Commission:** On the question of a single carbon intensity value for electricity versus one that actually reflects the underlying resources that are delivering the carbon; I understand all of the reasons why you all have headed down the path that you have, but I think for consumer information value and transparency a consumer who is paying a lot of money for a plug-in hybrid or an electric vehicle is entitled to know what the carbon value is of his or her action is. Given a single carbon intensity value just peanut butter's that value. So it both has a market integrity affect and a disincentive to folks to move faster to acquire these vehicles. On the question of 2022, 2024 and 2020 compliance period horizon, at some level I'm relatively indifferent as to what

number you pick as long as there is a way to characterize the outcome at 2020. So if the analysis can do a look back as well as a look forward, there is no great magic to the state's 2020 goal of emissions reduction, but there is a lot of policy significance to it. And if we are asking other sectors to try to meet that 2020 goal or aim toward that 2020 goal, I think it is important that the vehicle sector and the fuel sector try to do so as well. Or at least to come up with a value that we are aiming at and a value that we achieve in 2020. So I think it is more a calculation issue than a compliance horizon period. But I would encourage us not to diminish the importance of that 2020 note. Thanks very much.

August 5, 2010 Advisory Committee Meeting

- **Todd Campbell, Clean Energy:** For a long time we've been overly dependent on one fuel source and have seen price hikes as a result. A low carbon fuel strategy is not only about Greenhouse gas emission reduction, but also about fuel diversity. Historically, trend of oil compared to natural gas transportation fueling, BTU price to price per barrel (of oil) has been about six to eight times, today it is about twenty times (in terms of price). There are opportunities where low carbon fuels make sense in this market place, and that should be considered as (LCFS) policy moves forward. It is dangerous, as was suggested earlier, to look to the low carbon fuel industry to make sure the LCFS program is successful. It is more important to make sure the regulated parties that are producing fuel are invested in this program. As a private company investing (low carbon fuels) capital in Oregon, we are concerned about deferrals that are applied industry-wide, and the potential for (low carbon fuel deficit) forgiveness. We want companies to invest in low carbon fuels, and believe there will be multiple players. Consumers will recognize choice in the market and (a diversity of low carbon fuels) will drive competition, resulting in lower fuel prices. We are surprised by the carbon intensity assumptions of natural gas extraction from shale and the impacts on indirect land use associated with the ILUC impacts table from the CARB workgroup presented today. (Clean Energy) has not seen this table prior to today, as it was generated in a closed meeting, and ask the committee to reserve judgment on the information in the table, due to the proprietary nature of the processes that were analyzed.

November 16, 2010 Advisory Committee Meeting

- **Mary Solecki, Environmental Entrepreneurs:** Hello, my name is Mary Solecki with Environmental Entrepreneurs, an organization that works with the NRDC as the independent business voice and I am advocating on their behalf for the implementation of a Low Carbon Fuels Standard across the country. I've been following these meetings via phone, and wanted to comment on behalf of the biofuels producers that I've been working with in Oregon, I urge you to incorporate the indirect land use change component into the program. The biggest lesson that we've learned from California is to strictly adhere to the compliance schedule, as it will be a predictable path of market opportunity for investors to follow.

United States Court of Appeals for the Ninth Circuit

Office of the Clerk
95 Seventh Street
San Francisco, CA 94103

Information Regarding Judgment and Post-Judgment Proceedings

Judgment

- This Court has filed and entered the attached judgment in your case. Fed. R. App. P. 36. Please note the filed date on the attached decision because all of the dates described below run from that date, not from the date you receive this notice.

Mandate (Fed. R. App. P. 41; 9th Cir. R. 41-1 & -2)

- The mandate will issue 7 days after the expiration of the time for filing a petition for rehearing or 7 days from the denial of a petition for rehearing, unless the Court directs otherwise. To file a motion to stay the mandate, file it electronically via the appellate ECF system or, if you are a pro se litigant or an attorney with an exemption from using appellate ECF, file one original motion on paper.

Petition for Panel Rehearing (Fed. R. App. P. 40; 9th Cir. R. 40-1)
Petition for Rehearing En Banc (Fed. R. App. P. 35; 9th Cir. R. 35-1 to -3)

(1) A. Purpose (Panel Rehearing):

- A party should seek panel rehearing only if one or more of the following grounds exist:
  - ► A material point of fact or law was overlooked in the decision;
  - ► A change in the law occurred after the case was submitted which appears to have been overlooked by the panel; or
  - ► An apparent conflict with another decision of the Court was not addressed in the opinion.
- Do not file a petition for panel rehearing merely to reargue the case.

B. Purpose (Rehearing En Banc)

- A party should seek en banc rehearing only if one or more of the following grounds exist:

- ► Consideration by the full Court is necessary to secure or maintain uniformity of the Court's decisions; or
- ► The proceeding involves a question of exceptional importance; or
- ► The opinion directly conflicts with an existing opinion by another court of appeals or the Supreme Court and substantially affects a rule of national application in which there is an overriding need for national uniformity.

(2) Deadlines for Filing:

- A petition for rehearing may be filed within 14 days after entry of judgment. Fed. R. App. P. 40(a)(1).
- If the United States or an agency or officer thereof is a party in a civil case, the time for filing a petition for rehearing is 45 days after entry of judgment. Fed. R. App. P. 40(a)(1).
- If the mandate has issued, the petition for rehearing should be accompanied by a motion to recall the mandate.
- *See* Advisory Note to 9th Cir. R. 40-1 (petitions must be received on the due date).
- An order to publish a previously unpublished memorandum disposition extends the time to file a petition for rehearing to 14 days after the date of the order of publication or, in all civil cases in which the United States or an agency or officer thereof is a party, 45 days after the date of the order of publication. 9th Cir. R. 40-2.

(3) Statement of Counsel

- A petition should contain an introduction stating that, in counsel's judgment, one or more of the situations described in the "purpose" section above exist. The points to be raised must be stated clearly.

(4) Form & Number of Copies (9th Cir. R. 40-1; Fed. R. App. P. 32(c)(2))

- The petition shall not exceed 15 pages unless it complies with the alternative length limitations of 4,200 words or 390 lines of text.
- The petition must be accompanied by a copy of the panel's decision being challenged.
- An answer, when ordered by the Court, shall comply with the same length limitations as the petition.
- If a pro se litigant elects to file a form brief pursuant to Circuit Rule 28-1, a petition for panel rehearing or for rehearing en banc need not comply with Fed. R. App. P. 32.

- The petition or answer must be accompanied by a Certificate of Compliance found at Form 11, available on our website at www.ca9.uscourts.gov under *Forms*.
- You may file a petition electronically via the appellate ECF system. No paper copies are required unless the Court orders otherwise. If you are a pro se litigant or an attorney exempted from using the appellate ECF system, file one original petition on paper. No additional paper copies are required unless the Court orders otherwise.

Bill of Costs (Fed. R. App. P. 39, 9th Cir. R. 39-1)

- The Bill of Costs must be filed within 14 days after entry of judgment.
- See Form 10 for additional information, available on our website at www.ca9.uscourts.gov under *Forms*.

Attorneys Fees

- Ninth Circuit Rule 39-1 describes the content and due dates for attorneys fees applications.
- All relevant forms are available on our website at www.ca9.uscourts.gov under *Forms* or by telephoning (415) 355-7806.

Petition for a Writ of Certiorari

- Please refer to the Rules of the United States Supreme Court at www.supremecourt.gov

Counsel Listing in Published Opinions

- Please check counsel listing on the attached decision.
- If there are any errors in a published opinion, please send a letter **in writing within 10 days** to:
  - ► Thomson Reuters; 610 Opperman Drive; PO Box 64526; Eagan, MN 55123 (Attn: Jean Green, Senior Publications Coordinator);
  - ► and electronically file a copy of the letter via the appellate ECF system by using "File Correspondence to Court," or if you are an attorney exempted from using the appellate ECF system, mail the Court one copy of the letter.

United States Court of Appeals for the Ninth Circuit

BILL OF COSTS

This form is available as a fillable version at:
http://cdn.ca9.uscourts.gov/datastore/uploads/forms/Form%2010%20-%20Bill%20of%20Costs.pdf.

Note: If you wish to file a bill of costs, it MUST be submitted on this form and filed, with the clerk, with proof of service, within 14 days of the date of entry of judgment, and in accordance with 9th Circuit Rule 39-1. A late bill of costs must be accompanied by a motion showing good cause. Please refer to FRAP 39, 28 U.S.C. § 1920, and 9th Circuit Rule 39-1 when preparing your bill of costs.

__________ v. __________ 9th Cir. No. __________

The Clerk is requested to tax the following costs against: __________

Cost Taxable under FRAP 39, 28 U.S.C. § 1920, 9th Cir. R. 39-1	**REQUESTED** *(Each Column Must Be Completed)*				**ALLOWED** *(To Be Completed by the Clerk)*			
	No. of Docs.	Pages per Doc.	Cost per Page*	TOTAL COST	No. of Docs.	Pages per Doc.	Cost per Page*	TOTAL COST
Excerpt of Record			$	$			$	$
Opening Brief			$	$			$	$
Answering Brief			$	$			$	$
Reply Brief			$	$			$	$
Other**			$	$			$	$
			TOTAL:	$			**TOTAL:**	$

* *Costs per page*: May not exceed .10 or actual cost, whichever is less. 9th Circuit Rule 39-1.

****** *Other*: Any other requests must be accompanied by a statement explaining why the item(s) should be taxed pursuant to 9th Circuit Rule 39-1. Additional items without such supporting statements will not be considered.

Attorneys' fees **cannot** be requested on this form.

Continue to next page

Form 10. Bill of Costs - *Continued*

I, , swear under penalty of perjury that the services for which costs are taxed were actually and necessarily performed, and that the requested costs were actually expended as listed.

Signature

("s/" plus attorney's name if submitted electronically)

Date

Name of Counsel:

Attorney for:

(To Be Completed by the Clerk)

Date

Costs are taxed in the amount of $

Clerk of Court

By: , Deputy Clerk