Western States Petroleum Association
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Catherine H. Reheis-Boyd
Executive Vice President and COO

April 21, 2009

Clerk of the Board, Air Resources Board
1001 I Street
Sacramento, CA 95814
Via electronic submittal to http://www.arb.ca.gov/lispub/comm/bclist.php

Re. **Notice of Public Hearing to Consider Adoption of a Proposed Regulation to Implement the Low Carbon Fuel Standard (LCFS) – Western States Petroleum Association's Comments**

Dear Clerk of the Board:

The Western States Petroleum Association's (WSPA's) comments on the above-referenced rulemaking are contained in this cover letter and several attachments. WSPA is a non-profit trade organization representing twenty-eight companies that explore for, produce, refine, distribute and market petroleum, petroleum products, natural gas and other energy products in California and five other western states.

As we approach an April 23 hearing date, it is evident there are many key elements of the LCFS program that are incomplete, and that these elements will not be completed in time for the hearing or even shortly thereafter. WSPA believes the ARB needs to complete all elements of the LCFS before adopting the entire regulation.

Due to the many uncertainties that still need to be addressed, WSPA has two primary requests of ARB. The first is that ARB should include a resolution at the April hearing directing staff to address the multitude of program issues that need to be completed before the proposed December Board hearing where the LCFS regulation will be revisited.

The second request, equally important, is for ARB to include a resolution at the hearing requiring detailed triennial reviews of the program to be incorporated in the regulation itself. Detailed information concerning these two primary requests follows in the body of this letter. The LCFS regulation, as one of first Early Action regulations to be adopted under AB 32, has been on a very aggressive timeline. That includes a directive for the ARB staff to produce a program that is inherently very different from the normal course of business at the agency.

Normally, in the transportation arena, ARB deals with fuel reformulations and vehicle emission standards. The LCFS is attempting to lower generic carbon intensity for the entire pool of transportation fuels, some of which have not been commercialized or even invented. It is the most far reaching transportation fuels activity ever, and relies on an intricate combination of fuels, vehicles and consumers to make it work.

WSPA prefers a performance standard, which is how the LCFS program can be characterized, rather than a set of mandates for certain fuels and volumes. This approach should help spur innovation in fuels.

We also support a back-end loaded compliance schedule for the program – one that recognizes the significant innovation that needs to occur in the transportation area in order to reduce carbon intensity to the required standards.
There is also general agreement the LCFS program is relying heavily on fuels and vehicles that have either not been produced yet, or are not currently commercially viable. This is similar to the ZEV program that has seen a multitude of changes over the past 20 years, following early optimism for innovative technology advancements that did not materialize in the marketplace as anticipated. The ZEV program has had to be altered every few years.

Overall, the comments we made in our February 13 submittal to ARB (Attachment 1) still stand as pertinent to the proposed regulation.

WSPA has five main concerns with the draft regulatory documents:

- The entire LCFS program needs to be finished before the Board adopts it. The regulation and supporting documents for the LCFS program need substantially more work before the program is complete enough for implementation and compliance.
- There is a need for a clear commitment in the regulation for completion of this work by the end of this year, and for triennial Board program reviews that include a stakeholder Advisory Group and full public process.
- The staff's economic analysis is inadequate. It relies on overly optimistic and very unrealistic assumptions about new technology costs and accounting for tax credits, and asserts that large volumes of specialized vehicles will be available at no incremental cost. The state's peer reviewer, Dr. John Reilly of MIT, agrees with us on this matter.
- There is no clear explanation as to how the state's LCFS program will be harmonized with other GHG/fuels programs that either exist already or are anticipated to exist shortly.
- The staff has not addressed whether the LCFS program, as currently crafted, will ensure adequate, reliable and affordable transportation fuel supplies and sufficient infrastructure. This is of great concern in a state that admittedly has placed itself previously in the position of being a fuel island with problems being created by the state's desire to lead the world – but with higher costs borne by consumers.

WSPA's specific comments related to our key points are listed below and on the following pages.

Uncertainties and Risks Dictate Triennial Periodic Program Reviews

Details of WSPA's main request to ARB, as summarized on the previous page follow. The request has been noted in two specific parts: a) ARB should include a resolution at the April hearing directing staff to address the multitude of program issues that need to be completed before the proposed December Board hearing where the LCFS regulation will be revisited, and b) ARB should also include a resolution at the hearing requiring detailed triennial reviews of the program to be incorporated in the regulation itself.

The current proposed regulation indicates a review would be conducted in 2012; however WSPA requests a formal review requirement also be included in the regulation for 2015, and any other points the Board feels may be necessary between 2015 and 2020.

The program reviews need to also involve a full public process, and we recommend the establishment of an Advisory Group open to all stakeholders. We support inclusion in the process of, at a minimum, the CEC and other key agencies, fuel providers, consumers, engine and vehicle manufacturers, and other key stakeholders. In addition, WSPA supports a regulatory hearing before the Board rather than a review being conducted only by the Executive Officer.

The regulation should include language outlining what is to be included in the review. The program review should include but not be limited to:

- The program's progress against the LCFS targets;
- Necessary adjustments to the compliance schedule;
- All feasible and cost-effective advances in fuels and technologies;
- An assessment of the supply and rate of commercialization of fuel and vehicle technologies;
- The LCFS program's impact on the state's fuel supplies;
- The program's impact on state revenues, consumers and economic growth;
- Identification of hurdles or barriers (e.g. permitting issues, infrastructure adequacy, research funds, etc.) and recommendations for appropriate remedies; and,
- All significant economic, fuel adequacy, reliability, and supply issues, and any environmental issues that have arisen.

The need for such reviews highlights the fundamental problem posed by the lack of a sound economic and feasibility analysis, and the incompleteness of the rule.

LCFS Regulation is Far from Complete

There seems to be general agreement, including ARB staff, that the LCFS program regulation is far from complete. The staff has identified many important issues that will be worked between now and a proposed December hearing.

Issues including: the assigned carbon intensities (CIs) for key fuel pathways; development of the credit/debit system so we can demonstrate compliance; interaction of safeguards in the RFS and LCFS; carbon neutrality; inclusion of sustainability concepts; and, solving the definition of regulated party for electricity will be provided to the Board for regulatory revisions at the December hearing.

We do not understand why ARB is moving to adopt the LCFS in April when ARB could have conducted the entire adoption hearing in December when almost all the regulatory elements should be ready.

To demonstrate the significance of gaps in the program at this point in time, we note the lack of several key carbon intensities for fuel pathways. Staff decided to construct two carbon intensity reduction silos at this point in time – one for gasoline and one for diesel (against our recommendation).

We are very concerned that ARB currently does not have any CI pathways completed for biodiesel, advanced renewable biodiesel or renewable diesel relative to the diesel silo. According to the scenarios developed by staff, these three fuels are supposed to provide 94%-100% of the diesel CI reductions, but we have no currency with which to formulate our plans for the program.

Similarly, for gasoline CI reductions, staff has not yet provided CI factors for cellulosic ethanol or advanced renewable ethanol, which our members need for compliance purposes. Electricity is expected to yield 9%-35% of the CI reductions required for gasoline, but ARB has not yet resolved how electric providers will participate.

When one combines this lack of CI's for these fuels with the lack of definition of regulated party on the electricity side, we are missing 90%-96% of the compliance pathway for the gasoline silo according to staff's scenarios.

Unknown Compliance Path for Regulated Parties

A significant problem for all regulated parties is that the lack of completeness of the regulation impairs our ability to comply with the regulation, as illustrated above.

Staff's documents do not include a demonstration of the availability and cost-effectiveness of sufficient lower carbon fuels (including production scale and distribution infrastructure) to meet the carbon intensity standards through 2020 using existing technologies. One of the anticipated benefits of the program was the expected construction of facilities to produce biofuels and other fuels in the state of California to generate "green" jobs, use local feed stocks and improve fuel reliability/security concerns.

Based on the current situation in the state, these anticipated developments are in question and ARB needs to assess whether these benefits will materialize.

Also, staff should have identified the degree to which meeting the LCFS will depend upon the development and commercialization of technologies and materials that are not now commercially available, to give some sense to policymakers of plausible response times and key uncertainties.

Economic Impact Analysis Relies on Extremely Optimistic Assumptions

WSPA believes staff's economic analysis uses extremely optimistic and unrealistic assumptions. We disagree with this approach, preferring a more realistic set of assumptions and the inclusion of a range of assumptions and conclusions. To address our concerns, WSPA contracted with Sierra Research to perform an analysis of the staff's economic assessment. The report is Attachment 2.

Contrary to staff's contention that the LCFS program will result in a cost savings to California motorists of up to $3.4 billion per year by 2020 ($11 billion over the program period), the Sierra analysis concluded that fuel costs will increase by approximately $3.7 billion per year in 2020, oxides of nitrogen (NOx) emissions will increase by more than 5 tons per day and there will be no detectable change in climate.

It is very important to note that Dr. John Reilly, the only peer reviewer who holds a PhD in Economics, made many of the same statements as Sierra Research. Although staff concluded that none of the peer reviewers provided comments that would require major modifications to either the proposed rule or the analysis used to support the proposal, we do not believe this to be an appropriate conclusion, given statements by Dr. Reilly.

For example,

- "The economic analysis was done incorrectly. It does not meet technical standards of economics. The baseline assumptions are mutually inconsistent, …", and,
- "…the estimate of economic impact on the State of California is done incorrectly because the tax and tax revenue implications are dealt with inappropriately", and,
- "Thus these tax expenditures should be added on as a cost to Californians, and the expenditures should be increased by an amount to account for the deadweight loss associated with tax collections", and,
- "Another critical issue is the accounting of only fuel and administrative costs and not of vehicle costs."

If ARB decides to ignore the clear statements of its peer reviewers, we question why the state bothers with the peer review process. This action undermines the credibility of the entire regulatory effort.

Our conclusion is the LCFS rulemaking looks very similar to the ZEV mandate regulation when it was first introduced, with unrealistic expectations about technology development leading to a need for reviews and amendments. We are concerned ARB has taken the same approach with the LCFS, and this is likely to lead to problems with the transportation fuels system.

It is almost impossible to analyze the economic impact of the LCFS, since key components of the regulation are still missing (such as the CIs for many of the fuel pathways). Therefore, we can't calculate how much of what kinds of fuels might be used to comply, whether there will be sufficient supplies, and what the cost impact might be.

As part of the review of the impact of the LCFS, we believe ARB should have conducted a thorough study of the transportation fuel system with the assistance of the CEC, to ensure no adverse consequences would be expected relative to existing infrastructure and fuel supply.

WSPA independently commissioned ICF International to study some of the aforementioned issues, and the result of their efforts, entitled, "Outlook for PADD5 Supply, Demand and Infrastructure based on 2009 EIA Energy Outlook" is available in Attachment 3.
In addition to our concerns about the credibility of the economic analysis, we are disappointed with the timing of its release. The analysis was released just recently, at end of the public process. It should

have received a thorough peer review and have allowed adequate time for a staff response well in advance of the upcoming hearing.

Demonstration of Physical Pathway/Registration of Biofuels Producers and Importers

The obligated party for oxygenate and biomass-based diesel is the producer or importer of these fuels/blend stocks. Producers are best positioned to determine the carbon intensity of the low carbon fuels they produce and to provide an initial demonstration of the delivery methods comprising the physical pathway by which their fuel can reach California.

ARB should consider adopting a registration program for producers of renewable fuel similar to the registration program under § 80.1150 of the Federal RFS program. An element of the registration would be certification of the carbon intensity of the fuel produced at the production facility and the physical pathway for that facility.

A listing of registered producers and their production facilities and pathways could be maintained on the ARB website and associated with the ARB carbon intensity look-up table. This public information would facilitate sourcing of biofuels/blend stocks.

A registration program could similarly be developed for importers of fuel into California. The importers are best positioned to satisfy the physical pathway requirements defined in Sec. 95484(d)(2). Similarly, registered importers could be listed in the ARB website providing information to parties requiring low carbon fuels/blend stocks.

Indirect Land Use Change

WSPA agrees that Indirect Land Use Change (ILUC) is an issue that needs to be addressed in the context of a LCFS program WSPA also agrees that an ARB Work Group involving experts from both sides of the debate on ILUC needs to be convened to ensure a balanced and transparent approach to further work on the ILUC issue. We believe the issue needs to be worked in concert with the sustainability issue.

Energy Economy Ratios

WSPA recently sponsored a technical evaluation of energy economy ratios (EER's) developed for the LCFS regulation. The results of that study, prepared by Energy and Environmental Analysis (EEA), were submitted to ARB staff on February 4, 2009, and are included in this submission as Attachment 4.

We are disappointed that the methodologies developed as part of that study were ignored by ARB staff, as EEA's treatment of on-road fuel economy and vehicle attribute differences for light-duty vehicles has a very sound technical basis.

In addition, WSPA is very concerned about the value of the EER assigned to heavy-duty CNG engines in the proposed regulation. This latter issue is highlighted below.

The proposed EER value for CNG in heavy-duty applications (0.9) is based on a single advanced technology engine meeting ARB's 2010 emissions standards. As noted in the staff report, this engine has less of a fuel penalty relative to diesel than most of the current CNG fleet.

While this engine technology is expected to be implemented to some extent in the future, the proposed EER value will be applied to the current vehicle fleet that does not include this technology. The EER for heavy-duty CNG in this rulemaking should be based on the current vehicle fleet (EEA recommends a value of 0.7, based on available data).

To the extent that more efficient advanced technologies are implemented, the EER value can be updated, perhaps as part of the Program Reviews. Establishing an overly optimistic EER that is not representative of the existing heavy-duty CNG fleet sets up a mechanism in which LCFS credits can be generated that are not justified or real.

This is the most transforming fuel regulation ever undertaken. We must get it right. There is too much at stake now and in the future if we get it wrong.

Adequacy, reliability and affordability of the transportation fuels mix will be essential to the long term success of California's LCFS program.

Sincerely,

Att. 1- WSPA February 13, 2009 Comments to ARB on LCFS Program
2- Sierra Research Report – Preliminary Review of the CARB Staff Analysis of the Proposed Low Carbon Fuel Standard
3 – ICF International – Outlook for PADD 5 Supply, Demand, and Infrastructure based on 2009 EIA Annual Energy Outlook
4 – EEA, Inc. – Energy Economy Ratios for Alternative Fuel Vehicles

c.c. Susan Kennedy, Chief of Staff, Office of the Governor
Victoria Bradshaw, Cabinet Secretary, Office of the Governor
Darren Bouton, Deputy Cabinet Secretary, Office of the Governor
Linda Adams, Secretary, California Environmental Protection Agency
Cindy Tuck, Undersecretary, California Environmental Protection Agency
Mary Nichols, Chair, California Air Resources Board
Members, California Air Resources Board
James Goldstene, Executive Officer, California Air Resources Board
Senator Darrel Steinberg, President pro Tem, California State Senate
Senator Dennis Hollingsworth, Senate Minority Leader
Assembly Speaker Karen Bass
Assemblyman Mike Villines, Assembly Republican Leader
Joe Sparano, President, WSPA

Appendix 1 – WSPA February 13, 2009 Comments to CARB on the LCFS Program

Western States Petroleum Association
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Catherine H. Reheis-Boyd
Executive Vice President and COO

February 13, 2009

Manisha Singh
Stationary Source Division
California Air Resources Board
P.O. Box
Sacramento, CA 95814
Via electronic mail

Re. **Western States Petroleum Association's Comments on ARB's LCFS Program -January 30, 2009 Workshop**

Dear Ms Singh:

Attached are the Western States Petroleum Association's (WSPA) comments on the most recent ARB release of LCFS program documents. WSPA is a non-profit trade organization representing twenty-eight companies that explore for, produce, refine, distribute and market petroleum, petroleum products, natural gas and other energy products in California and five other western states.

WSPA's comments address not only the material provided at ARB's January 30 LCFS workshop, but also reemphasize several issues contained in our previous comment letters. We have included many previous comments since WSPA has not yet received an explanation from ARB as to whether or how our previous comments have been addressed. In general we are disappointed with ARB's apparent decision to ignore or disagree with the majority of our prior comments without an attempt to discuss the issues with our industry – the industry which is impacted the most and is directly responsible for implementation of the LCFS program.

We have several general comments captured in this cover letter followed by detailed comments. For ease of reference, general comment headings are bulleted here with details within.

- LCFS program needs substantially more work before the adoption hearing
- Need clear commitment in regulation for adequate periodic regulatory review with public process
- Inadequate economic analysis
- Harmonization with other GHG/fuels programs
- Guarantee of an adequate, reliable and affordable transportation fuel system

LCFS Program Needs Substantially More Work Before the Adoption Hearing

We are approximately one month away from submittal of the ARB documents to OAL and release to the public. Our overall impression is there are many open or only partially addressed facets of the program.

ARB staff continues to hold public workshops, but the workshops merely present summary slides of conclusions on a number of aspects of the program. There are no detailed explanations of the assumptions or calculations behind the results. It is impossible for the public to comment effectively.

In addition, there are many references to the “staff still quantifying, latest documents do not reflect comments, we are evaluating this issue, preliminary results will be published upon completing review, etc.” It is clear to WSPA at this point in time that the LCFS Program needs substantially more work to ensure good science is applied to the regulation, and to verify that it is sufficiently complete.

During the January 30 workshop, staff produced a slide listing the issues that require additional effort. They were: early years cap, fee schedule (we request clarification of what this is), incentivizing carbon capture & sequestration, calculation of violation days, California average crude mix vs. others, method 2A & 2B, and physical pathway. Also, every other facet of the staff materials contains references to additional basic work that needs to be done, not just the finishing touches.

In particular, some very major aspects of the program are still incomplete or unresolved. These include defining a feasible pathway, the treatment of different crude oils, indirect land use factors for biofuels, and lifecycle assessments and pathway documents for a number of alternative fuels.

WSPA is concerned that one of the key elements of the program, the carbon intensity lookup table B1, was distributed at the January 30 workshop with different numbers than had been displayed on ARB’s website as the “new” numbers just 10 days beforehand. We have no confidence that the fuel carbon intensity numbers are anywhere near completion. Our industry cannot, therefore, determine if there are viable low carbon intensity fuels we can use to comply with the program – even in the initial years.

In addition, WSPA believes ARB staff recognizes the program is not ready for early implementation since they released a LCFS compliance schedule that has no requirement for carbon intensity reductions in the year 2010. The whole year will be merely a reporting year with compliance not beginning until 2011.

The agency appears poised to adopt a shell of a regulation with the hope that changes, many of them potentially very significant, can be accomplished by the end of 2009 and in future years. The new regulatory schedule, in fact, indicates the April Board hearing is only the first time in 2009 when the LCFS will be addressed, since in December 2009 there will be a “completion of the April LCFS rulemaking process” and an “update to the regulation.”

WSPA believes this bifurcated rulemaking approach is confusing, unnecessary and clearly indicative of the inadequate state of the proposed regulations. We believe CARB should ensure all the work is adequately done during the 2009 period and one adoption hearing be held in December, or at such point in time when an appropriate and complete package is ready.

<u>Need Clear Commitment in Regulation for Adequate Periodic Regulatory Review with Public Process</u>

The LCFS is an exceptionally challenging rulemaking because the feasibility of achieving the goal of a 10% reduction in carbon intensity by 2020 will require fuel and/or vehicle technologies that do not currently exist. As a result, WSPA feels it is imperative that ARB include, at a minimum in the Resolution but preferably in the regulatory language, a clear description of a mandatory periodic program review including a full public process.

WSPA feels very strongly that the LCFS regulation should require a periodic review on the order of every three years, not just one review in 2012, as has been proposed by staff. In addition, we request the reviews be public processes, not just performed by the Executive Officer or ARB staff with no public input or review.

We also request that the regulation contain language specifying the scope and content of the reviews so there is no ambiguity about what the review is meant to cover. The reviews should evaluate the program's progress against the targets and make adjustments as necessary.

Any economic and environmental issues that have arisen should also be analyzed. Some of the aspects that should be addressed in the periodic reviews are:

- any technology advances;
- an assessment of the supply and rate of commercialization of fuels and vehicles;
- the program's impact on the state's fuel supplies;
- the program's impact on state revenues and consumers; and,
- identification of hurdles or barriers (i.e. permitting issues, research funds, etc.) and recommendations for appropriate remedies.

It is important the periodic reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The periodic reviews should be conducted by key agencies and stakeholders including but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers.

Inadequate Economic Analysis

One of the elements we find particularly lacking is an adequate economic analysis of the program. We are also disappointed this critical element of the regulatory process has only now begun to be discussed with the public as the documents are due to be released for the 45 day review before the adoption hearing.

The staff proposal to create an Economic and Environmental Workgroup early in the process never materialized. We think this has been detrimental to the process. WSPA believes the economic analysis summarized at the January 30 workshop is inadequate, and we question the cost assumptions and conclusions. An economic analysis is so core that it requires visible and credible support.

We have appended our contractor's initial overview comments on this issue for a second time since we would like to keep emphasizing his points. In general, he highlighted the following:

"… three issues that CARB needs to consider carefully in performing its economic analysis of the Low-Carbon Fuel Standard (LCFS):

- *Uncertainty*
- *The appropriate baseline against which to measure costs*
- *Alternative scenarios necessary to understand the cost of the LCFS*

The economic impacts of the LCFS could be among the most significant of any element of CARB's AB 32 Scoping Plan. Moreover, it is possible that adjustments to the design of the LCFS could *significantly reduce its cost and the economic risks that it poses. Therefore, sound and comprehensive economic analysis is immensely important in order to inform CARB's decisions in implementing the LCFS."*

Cost-effectiveness of the program is critical – not only legally for the state of California but also in case the program is applied elsewhere within the nation or internationally. A program that is devised in such a manner as to be uneconomic and unworkable will not only encumber and risk the viability of California's transportation fuel system, but will have the same impact on any area that adopts it.

WSPA requests that ARB engage the same peer review team that reviewed the AB32 Scoping Plan in order to receive constructive input and lend transparency and credibility to staff's work.

<u>Harmonization with Other GHG/Fuels Programs</u>

ARB needs to explain in the LCFS regulation how it anticipates handling the LCFS program and the Transportation Fuels under a Cap & Trade program that has been imported into the Scoping Plan from the WCI. Does the state expect to have separate LCFS and cap and trade components for transportation fuels? How are both these programs going to relate to the federal EISA or RFS2 requirements? How are the California GHG/LCFS programs going to relate to the RFS2 and to any future federal climate change programs including a LCFS, when they are adopted?

The answers to such questions could have a significant impact on the ability of WSPA member companies to comply with multiple programs. It is only through clear discussion of these questions that stakeholders can effectively respond to the draft LCFS regulations in a meaningful, value-added and all-encompassing fashion.

Crediting AB 32 cap and trade refinery GHG reductions to the LCFS is another issue requiring further discussion. Will AB 32 GHG emission reductions be allowed to be used to comply with future LCFS requirements? Will AB 32 reductions be reflected in future default carbon intensity values for gasoline and diesel? Does ARB foresee changing any limitation on the use of excess LCFS credits in complying with the AB 32 requirements?

ARB has said an adjustment will need to be made to the AB32 Scoping Plan due to the double crediting of electricity GHG reductions for the AB 1493 Pavley regulations. ARB also needs to describe clearly how those adjustments will be made and how they intend to make consistent changes for any double-crediting between the LCFS, Pavley and AB32 programs for other fuels.

One of the goals of the AB 32 and LCFS programs is to reduce petroleum use significantly by 2020. Estimates in the document are the programs will result in a 25% gasoline reduction and more than 15% diesel reduction. If true -- will the associated refinery GHG reductions from cutting back production be credited to the cap/trade program?

ARB and the CEC are implementing plans to spend approximately $200MM/year for several years to help reduce GHG and other emissions under AB118. Since AB 118 funds are not to be spent to help parties comply with existing laws, regulations, etc, how will the resulting surplus GHG emissions be accounted for under the Scoping Plan and the LCFS?

Guarantee of an Adequate, Reliable and Affordable Transportation Fuel System and Fuel Supplies

We want to reiterate WSPA's fundamental concern that California and its citizens will be negatively impacted by any adverse consequences on the state's transportation fuel system as a result of implementation of the LCFS.

Since the LCFS includes very new compliance and enforcement concepts, the state needs to be more aware of the complications that will likely arise in the implementation of the program. The state also needs to examine the risks inherent in imposing such significant changes on the state's transportation fuel system.

The ARB must acknowledge the importance of ensuring adequate and reliable energy supplies, including transportation fuels, during the implementation of the LCFS. In addition, ARB needs to work with other California agencies such as the CEC to ensure that the state's transportation fuel supply requirements will be met, and there will not be any negative economic impacts on consumers and businesses.

We recognize that transportation fuels, the vehicles that use the fuels, and the vehicle-miles-traveled (VMT) all play a part in contributing to a reduction in GHG emissions from the transportation sector. This sector, however, is also very important to ensuring the economic health and welfare of the state and its citizens, and deserves careful thought, the use of sound science and careful planning in the implementation of a LCFS program.

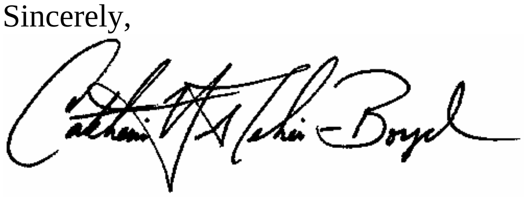
There is only one month remaining before the ARB staff documents are released to the public and less than three months remain until the adoption hearing. There are many other states and areas of the world watching California's actions.

WSPA is extremely concerned about the situation. We question whether sufficient time, thought and good science has been and can be applied in the time remaining that is dedicated to develop a workable, effective LCFS under the current timeframe.

We will continue to work with ARB and request that our comments be considered seriously. As always, WSPA is available to discuss our comments with you and we welcome an opportunity to discuss staff's responses to our earlier comments and concerns.

If you have any questions regarding our comments, please contact me or Gina Grey at 480-595-7121.

Sincerely,



c.c. Linda Adams, CalEPA

Cindy Tuck, CalEPA

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WESTERN STATES PETROLEUM ASSOCIATION'S COMMENTS ON CARB'S LCFS PROGRAM REVISED DRAFT LCFS REGULATION

ECONOMIC ANALYSIS

The issues of life cycle analysis, economic analysis, periodic program review, and technical feasibility are interconnected. Ensuring that a quality economic analysis is performed is a key to the development of a successful LCFS program.

First, WSPA would like to register our disappointment with the LCFS process relative to economic and environmental issues. ARB never convened the Environment & Economic Working Group.

ARB should have worked on the initiation of the economic & environmental analyses on a parallel track with the other workgroups. At a minimum, the workgroup could have engaged in a discussion of and potential agreement on the appropriate methodology and process.

Instead, the analysis is being rushed at the end of the staff LCFS program development and is inadequate. Moreover, it appears from the material shared to date that ARB has reached conclusions on the economic impacts of the LCFS program without first conducting a thorough analysis.

In addition, ARB staff is not sufficiently trained in economics in order to perform an appropriate analysis.

We question staff's capability to make a critical evaluation of an outside feasibility study, and whether they have the engineering research capability to evaluate whether some speculative processing technology can be implemented within a given cost estimate. For example, WSPA and other stakeholders need to see the underlying work that leads to ARB's assumption that low carbon fuels that do not now exist will be available at lower costs than conventional fuels.

WSPA points out recent studies indicate the federal program capital cost is potentially $11 trillion, so we question the very low estimates provided by ARB. We note that ARB's outline doesn't include new alternative fuel infrastructure expenses or the cost of alternative fuel plants.

Our economist, Jud Jaffe's, comments are provided in Appendix 1. He highlights that ARB's initial economic analysis for the LCFS rule should include the following:

- Final LCA numbers prior to completion of the economic analysis;
- Identification of tonnage reductions that are attributable to the gasoline program, and reductions attributable to the diesel program;
- Cost estimates (in $/ton) for each of these two sets of reductions, for each year of the program;
- Comparable estimates for cost of reductions if there was only one combined gasoline-diesel reduction requirement;
- For the proposed reductions for the first three years of the program before the first review, ARB must determine whether the proposed reductions can be achieved with currently available materials and technologies, and the cost estimates based upon those materials and technologies; and,

- For each periodic review, necessary adjustments to life cycle analysis are made, and the upcoming four years' proposed reductions are tested for feasibility based upon then currently available materials and technologies.

We believe an independent third party economist, or better yet a team of economists similar to what the state did for the AB32 Scoping Plan, is needed to assess the LCFS. In addition, we request that this peer review be conducted well in advance of the hearing so there can be adequate public review and discussion of the review contents. The team of peer reviewers should also be asked to present a summary of their findings at the adoption hearing.

Cost-Effectiveness – ARB Focus on "Out Years"
WSPA has frequently stated the need for a thorough cost effectiveness and feasibility review of the LCFS program. ARB is required to provide these analyses under AB32 for any Early Action measures.

ARB's current analysis of fiscal impacts seems to be focused on the out years of the program (i.e., towards 2020). Given this is the most speculative timeframe in terms of the nature and availability of the required technology, it is relatively easy for staff to postulate on successful scenarios for complying with the LCFS.

ARB should make different forecasts for the early years (nominally 2010-2015) than for the later years (nominally 2015-2020). The difference between the two would be the planned program reviews: in the early years (i.e., before the program reviews have an opportunity to have much of an impact) ARB needs to demonstrate that sufficient quantities of required low CI fuels *using currently available technology* will be available to meet the proposed goals. In the later years, the regulations need to reflect the greatest possible commitment (through the program reviews) to updating the feasibility analyses based on what actually transpires between now and then.

ENVIRONMENTAL ANALYSIS

I. Multimedia Evaluation Now Required Under Health & Safety Code § 43830.8

Starting in 1999, the California legislature required multimedia evaluations in order to obtain a full and independent assessment of the range of potential environmental impacts of any newly proposed fuel regulations across all media, including air, water, and soil.

At a minimum, all multimedia evaluations must address, among other items: "Emissions of air pollutants, including ozone forming compounds, particulate matter, toxic air contaminants, and *greenhouse gases*." Health & Safety Code, § 43830.8(c)(1) (emphasis added). By its terms, the required multimedia evaluation applies to the greenhouse gas (GHG) impacts of fuel regulations, including the LCFS which is primarily designed to reduce GHG emissions.

Under the detailed provisions of Health & Safety Code § 43830.8, ARB must conduct a multimedia evaluation before adopting a motor vehicle fuel regulation such as the low-carbon fuel standard (LCFS). Specifically, under Health & Safety Code § 43830.8, ARB may not adopt any regulation that establishes a specification for motor vehicle fuel unless that regulation, and a multimedia evaluation conducted by affected agencies and coordinated by ARB, are reviewed by the independent California Environmental Policy Council ("Council").

ARB is permitted to adopt a regulation without a multimedia analysis only if following an initial evaluation of the proposed regulations, the Council "conclusively determines that the regulation will not have any significant adverse impact on public health or the environment." Id. at § 43830.8(i). The Council has not made this conclusive determination regarding the LCFS and has no basis for making such a determination.

II. The LCFS Should be Subject to a Multimedia Evaluation

ARB staff currently proposes to avoid the California statutory requirements for performing a multimedia analysis by asserting that the LCFS is not a fuel "specification." ARB Presentation, *Requirements for Multimedia Evaluation and the Low Carbon Fuel Standard (LCFS)* (October 15, 2008) ("*LCFS Multimedia Presentation*"), at p. 4. According to ARB staff, the requirement to reduce carbon intensity does not establish a motor vehicle fuel "specification," because such a requirement is not a "detailed description of the design and materials used to make something." Id. at p. 5 (citing Oxford American Dictionary).

However, carbon intensity is a criterion or "specification" to which motor vehicle fuels must comply. The LCFS will change specifications of California reformulated gasoline and diesel and will require fuel additives to be added or taken out and new fuels to be used statewide. ARB Draft LCFS Regulation, Section 95422 ("[T]he transportation gasoline and diesel fuel for which a regulated party is responsible in each calendar year must meet the average carbon intensity standards set forth in this section . . . ").

ARB is not permitted to avoid the statutory requirements under Health and Safety Code, § 43830.8 to perform a multimedia evaluation by simply labeling the LCFS a "standard" as opposed to a "specification." Any attempt to do so is contrary to the legislative mandate in AB 32 that ARB must comply with existing fuel regulations in satisfying its obligations under AB 32. Health & Safety Code, § 38598(b) ("Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulations.").

ARB staff promises that ARB will perform a multimedia analysis if and when ARB either adopts a new fuel specification (such as one for biodiesel or biobutanol) or amends an existing fuel specification (such as natural gas or E85). *LCFS Multimedia Presentation*, at 9. According to ARB, in order to implement the "spirit" of Health and Safety Code § 43830.8, "[ARB] staff will conduct a functionally equivalent assessment for the LCFS rulemaking." Id. at 8.

Such an approach fails to address upfront the adverse environmental impacts that are associated with producing fuels that can meet the carbon intensity requirements under the LCFS. Such an approach also ignores the possibility that ARB may never conduct a multimedia evaluation of all of the LCFS fuels pathways. It completely ignores the possible interaction between alternative fuels pathways that might produce cumulative impacts.

Examples of multimedia impacts are described in the University of California Study, which concluded that increased biofuel production will result in adverse water and land use impacts. *University of California Study: A Low Carbon Fuel Standard for California* ("*UC Study*"):

- *Part 2: Policy Analysis*, at 74: Noting the numerous sustainability issues associated with biofuels, such as degraded air and water quality, soil erosion, loss of biodiversity, loss of wilderness and natural habitats, increased concentration of land holdings and land appropriation.

- *Part 1: Technical Analysis*, at 72: "Transportation fuels have environmental impacts beyond greenhouse gas emissions [that include] land-use change, ground- and surface-water contamination, criteria and toxic combustion emissions, environmental impacts of perturbations to the complex nitrogen cycle, soil erosion and loss of soil nutrients, pesticides, water depletion, and environmental impacts of electricity."

- *Part 1: Technical Analysis*, at 8-9: "[A]ir quality, water use and quality, loss of habitat, soil erosion . . . will become more important if biofuel production and use expand . . . ."

- *Part 2: Policy Analysis*, at 75: "We also recommend that the state conduct independent periodic assessments of the sustainability impacts of the LCFS policy."

More recently, ARB prepared a California Environmental Quality Act (CEQA") Functionally Equivalent Document that analyzed the potential adverse environmental impacts of the Proposed Scoping Plan. *CEQA Evaluation of Environmental Impacts, ARB Climate Change Proposed Scoping Plan, Volume III, Appendix J* ("*FED*"). In the *FED*, ARB highlighted the impacts to air and water quality, and land use planning associated with the biofuels pathway of the LCFS.

Specifically, ARB concluded that production of food crop for biofuels may create new emission sources for acquiring feedstock, increase water demand, and impact water quality given increased use of chemicals and fertilizers to grow crops. *Id.* at J-28, J-66. In addition, ARB determined that there are "potential land resource issues associated with the biofuels pathways, such as conservation of forestlands, pastureland, and food or fiber to fuel crops." *Id.* at J-54.

Further, in each of the sections discussing the impact of the LCFS on a particular media (*i.e.*, air, water and land), ARB determined that additional analysis of these issues will be required as part of the LCFS regulatory process:

- *FED*, at J-27: "The LCFS regulatory proposal will contain a more detailed analysis of the potential air quality impacts";

- *FED*, at J-66, J-67, J-97: Noting that water quality and resources issues will be further discussed and analyzed in the LCFS regulatory development process;

- *FED*, at J-54: Stating that land resource issues associated with the use of biodiesel, ethanol and hydrogen "will be further evaluated in the LCFS regulatory development"; and,

- *FED*, at J-56: "[T]he potential impact of the loss of production of food and fiber may be significant, and would require further environmental analysis."

Thus, it is clear that ARB has yet to evaluate sufficiently the environmental impacts associated with increased use of biofuels, and that further CEQA analysis is necessary as part of the LCFS regulatory process. However, the statutory requirement to comply with CEQA (Public Resources Code, § 21000 *et seq*.), and the regulation of fuels (Health and Safety Code, § 43830 *et seq*.) are separate and distinct.

Compliance with CEQA is therefore not a substitute for the statutory requirement to complete a multimedia evaluation when adopting a motor vehicle fuel specification, and any attempt by ARB to do so would be improper.

Although ARB has begun a multimedia evaluation for biodiesel, and completed a limited evaluation for ethanol several years ago, other fuels that could comply with the LCFS, such as hydrogen, and natural gas have not undergone full multimedia evaluations. ARB will need to undertake multimedia evaluations for these remaining potential pathways to determine if any such fuel can qualify as an available pathway for compliance with the LCFS.

In addition, we question whether the earlier limited multimedia evaluation for ethanol needs further evaluation to incorporate other feedstock pathways and processing; beyond the singular assumptions made earlier.

III. <u>Failure to Complete a Multimedia Evaluation Up Front Will Delay the Development of LCFS-Compliant Fuels</u>

The proposed ARB staff approach to conducting multimedia evaluations after adoption of the LCFS will cause uncertainty. It will also hinder the development of the full range of LCFS-compliant fuels.

Specifically, uncertainty as to whether a fuel will satisfy a multimedia analysis will delay development of such fuels based on concerns about allocating any significant resources to the commercialization of a fuel that could ultimately fail such analysis. Likewise, the cost of developing fuels will increase if LCFS-compliant fuels are developed that ultimately fail to satisfy the requirements of a proper multimedia evaluation.

Thus, ARB should conduct multimedia evaluations *now* for all of the likely LCFS-compliant fuels in order to encourage investment in and development of a full and competitive range of such fuels. The deadline for implementing early action measures under AB 32, such as the LCFS, is fast approaching, and any delay in the development of LCFS-compliant fuels will further add to the many challenges and risks of implementing AB 32 successfully.

We appreciate that ARB is currently conducting a MMA for biodiesel (FAME only) and that reportedly a renewable diesel MMA is also underway. The Tier 1 report for the FAME biodiesel was recently made available for review. Tier 2 and 3 reports are still pending. The document, by design, covers an enormous amount of information and its release was delayed several months as the various agencies worked on the draft. This document and the time and resources it took, emphasizes the need to get started on any other MMA that needs to be done prior to the implementation of the LCFS. Whether or not various agencies have the resources available to deal with upcoming MMA's is also a real concern that ARB needs to address in their rule package to their Board.

<u>COMMENTS ON PORTIONS OF THE DRAFT REGULATION</u>

[Note: Many of the regulatory section numbers have been revised recently, however we have not been provided with a new, complete regulation. As a result, WSPA reference to regulatory sections may be inaccurate.]

Full Text of Proposed Regulation

At ARB's last workshop staff distributed only sections of the regulation which had been revised recently. This led to a great deal of confusion. WSPA requests that ARB release online a full version of the revised regulation with all of the correct section numbers.

95420. Definitions and Acronyms

Please note our comments on section 95424 regarding definitions of producer/production facility.

Importer:
( ) "Importer" means the person who owns an imported product when it is received at the import facility in California.
( ) "Import facility" means, with respect to any imported liquid product, the storage tank in which the product was first delivered from outside California into California, including, in the case of liquid product imported by cargo tank and delivered directly to a facility for dispensing the product into motor vehicles, the cargo tank in which the product was imported.

Under the current CBG rules, import facility has a broader definition and allows the use of protocols where a vessel can be considered the import facility instead of a "storage tank". We'd request similar flexibility under this rule as well.

WSPA also asks ARB to include in the LCFS a provision that allows staff to develop protocols to cover many aspects of the LCFS.

(24) "Regulated party" means a person who is subject to the LCFS pursuant to section 95424(a), and must meet the low carbon fuel standards in section 95422. Section 95424 defines the regulated party for an oxygenate (e.g. ethanol) as the producer or importer of the product. Therefore they appear to be subject to the standards in 95422. Is this understanding correct?

95420. Applicability of the LCFS

- WSPA continues to encourage ARB to revise the draft program design to focus on a gasoline-only program in the early years, with the potential to expand as the ability to comply is assessed during ARB's periodic reviews. As indicated later in our comments, ARB has not been able to demonstrate there will be sufficient volumes of low carbon intensity fuels for the diesel pathway, for example.

  During the regulatory process we often find ARB stating that no alternative options were presented so they indicate this is justification for moving forward with their singular approach. We would ask that ARB at least analyze the "gasoline-only" program as an option and provide the details of the analysis. One reason given by ARB staff to reject this scenario is that it will not provide the same number of CO_2 tons of reductions. For two reasons this is a superficial and unsupportable excuse.
    - First, the major goal of the LCFS is to promote technology advancement – something that focusing on tons of CO_2 reduction would not do. If the assessment says that the LCFS will provide fewer tons the Scoping Plan could be revised.
    - Secondly, there is little evidence provided by ARB that the current program, especially the diesel pathway, is technically feasible so the tons of CO_2 credited to the ARB current

proposal is an illusion and it is unjustified to require that an alternative program be required to meet an unrealistic comparison.

- If ARB insists on moving forward with a flawed approach that includes more than gasoline during the program's initiation, this section of the draft regulation still does not adequately define exactly what fuels fall under the LCFS, but just lists several transportation fuels (e.g. electricity is not among those listed). WSPA suggests verbiage as follows, which is copied from ARB's Supporting Documentation (3rd and 4th paragraphs on page 4).

  For the LCFS, transportation fuel means any fuel used or intended for use as a motor vehicle fuel, other than racing fuel. In addition, transportation fuel includes diesel fuel used or intended for use in nonvehicular sources other than interstate locomotives, aircraft, and marine vessels (except harborcraft). .....

  > The definition of transportation fuels essentially covers the types of use that are subject to ARB's current standards for gasoline and alternative fuels. In California, "motor vehicle" is defined broadly to include off-road construction and farm vehicles. In addition, "transportation fuel" includes diesel fuel used in non-vehicular sources that are currently covered by ARB's standards for ultra-low sulfur diesel fuel (ULSD). This includes all applications other than locomotives that are not subject to ARB's diesel fuel standards for intrastate locomotives, and marine vessels that are not subject to ARB's diesel fuel standards for harborcraft. Since this broader pool of diesel fuel is all currently subject to the same ARB ULSD standards, there has been no need to segregate different batches being used for vehicular versus covered non-vehicular applications.

- Consistent with the above, we believe that CARB ULSD which complies with the LCFS for use in LDDVs needs to be treated the same way electricity or natural gas is treated. Specifically, diesel's inherent fuel efficiency needs to be credited the same way electricity is proposed to be treated. ARB staff and even Board members are quoted in the public as attesting that the LCFS is fuel neutral, that all fuels are treated the same and the industry gets to pick the fuels they use to comply. Obviously, that is not true given the current LCFS proposal.

Regarding the exemptions found in 95420(b)(1) or 95421(c)(1), we don't fully understand this concept. ARB should provide examples of what "non-biofuels" are subject to this exemption (LNG, CNG, electricity, hydrogen, etc?).

Section 95421. Applicability

Credit Generation Opt-in Provision for Specific Alternative Fuels

WSPA is very concerned and confused by this new addition to the regulation. We believe it is premature to presume the fuels listed will have a full fuel-cycle carbon intensity that meets the compliance schedules through 2020. This does not portray a purported equal or fuel neutral treatment by ARB. In other sections ARB works to ensure the market for LCFS credits will not be manipulated by traders and other non-obligated parties. Why is ARB treating electricity generators differently than other parties?

We do not understand nor do we agree with the proposal that the regulated party for those fuels must meet the requirements of the LCFS only if they choose to generate credits. We are concerned there may be several reasons (e.g. AB118 funding program restrictions or aversion to reporting requirements) that may encourage these alternative fuel parties to not bother with the program credits and our industry will be unable to comply. They could continue to supply fuels to vehicles but would be outside the LCFS program.

We request this additional section 95421(b) be deleted.

Exemption for Specific Alternative Fuels

WSPA is concerned with the amount of fuel being designated as the volumetric limit for an alternative fuel that is exempted from the program. This seems to be a high volume allowed especially when one considers the anticipated small penetration rate of vehicles utilizing these fuels. We do not support any transportation fuel being exempted from the LCFS regardless of the volume.

In addition, the inclusion of LPG as an exempted fuel in relation to the other alternative fuels does not appear to be valid.

We request that this provision be deleted.

Compliance Schedule

- WSPA generally supports the backend loaded compliance curve proposed by ARB. However, we are concerned about the feasibility of meeting the 2015 to 2020 interim targets because these are based on projections of new technology developments needed to meet the target. Because of the difficulty in predicting advances in technology we believe triennial reviews of the program must be carried out and the interim target feasibility be assessed. As stated earlier, these reviews should be made a requirement in the LCFS regulation. Additionally, we recommend ARB include some comparative analysis showing ARB's compliance schedule in comparison with the federal EISA schedule. Furthermore, the fact the European Fuels Directive reduced their LCFS target for transportation fuels from 10% to 6% due to a concern over feasibility. It is our understanding that if the EU Commission finds, through its own periodic reviews, that a 10% reduction is feasible it would likely be reinstated. This same analysis and flexibility should be addressed in the California LCFS program documentation.

- Unfortunately, without all of the carbon intensity numbers being completed (including land use considerations) we have to reserve our comments even for the early years of the program. At this point we cannot conclude whether the schedule is too stringent or not.

- Moreover, once ARB has completed the carbon intensity value calculations for fuels, the agency still needs to evaluate the feasibility of the program.

- WSPA notes staff has altered the compliance schedule to only require reporting during 2010 which makes 2011 the first year of carbon intensity reductions. WSPA believes this is a prudent step given the complexity of the regulations and the short timeframe industry will have to prepare. We seek confirmation that while 2010 only requires reporting regulated parties could still realize credits for reductions made in 2010 and bank such credits for future use.

- In supporting its draft regulation for the California low carbon fuel program, ARB lays out compliance scenarios that contemplate the availability of over 2.24 billion gallons of advanced renewable fuels and over 560,000 advanced vehicles (battery, plug-in hybrid, and fuels cell) in California in 2020. These expectations are unrealistic.

ARB's projection that 560,000 advanced vehicles will be available for sale in California in 2020 appears unsupported and, in fact, contrary to the Energy Information Administration's (EIA) forecast. National growth trends do not appear to support 560,000 advanced vehicles in California by 2020.

Table 1, below, reflects the EIA's 2008 Annual Energy Outlook (2008 AEO) forecast of sales in the Pacific Region of unconventional light-duty vehicles in 2020. This forecast is based on the latest data and national economic model, and factors in the effects of the 2007 EISA updates to the federal renewable fuel standard (RFS) and the corporate average fuel economy (CAFÉ) standard.

As shown in Table 1, the 2008 AEO projects the sales of electric hybrids, fuel cell, and gaseous and electric light-duty vehicles in the Pacific Region to grow from a total of about 50 thousand to around 380 thousand between 2006 and 2020. That growth trend will not support sales anywhere near 560,000 advanced vehicles in California in 2020.

Table 1. Sales of Unconventional Light-Duty Vehicles by Fuel Type 2006-2020, Pacific Region

	2006	**2020**
Total	52,400	380,200
Electric hybrid	50,500	375,300
Gaseous technology	1,900	1,600
Fuel cell and electric	0	3,300

Source: Department of Energy, Energy Information Administration, 2008 Annual Energy Outlook, Supplemental Data, Table 46, June 2008.

ARB says the 560,000 advanced vehicle projection is consistent with the penetration schedule used to develop their 2008 ZEV regulation. ARB's ZEV program, first adopted in 1990, has as its first objective the promotion of electric vehicle technology. While major technology advances have occurred, the program has been amended four or five times over the past 18 years because the vehicles have not shown up in the marketplace. ARB has consistently overestimated the availability of electric vehicles and the state of technology and underestimated the cost.

ARB's projection that 2.24 billion gallons of advanced renewable fuel will be available for sale in California in 2020 appears unsupported and contrary to current figures. That amount significantly exceeds California's historical share of the national transportation fuels market.

The federal Energy Independence and Security Act of 2007 (2007 EISA) aggressively expands the federal Renewable Fuels Standard and provides a list of financial and other incentives for the production and use of these fuels. It mandates aggressive sales volumes of renewable fuels, advanced biofuels, and cellulosic biofuels.

The 2007 EISA mandates the sale in 2020 of at least 15 billion gallons of advanced biofuels, of which at least 10.5 billion gallons must be cellulosic biofuel. California typically uses 10 or 11 percent of the nation's transportation fuels. Consequently, it is difficult to see how California would be able to attract 2.24 billion gallons in 2020, since that would be about 15 percent of the national requirement.

On the other hand, if California was to continue getting the same share of renewable fuels as it does today the nation would have to produce over 22.4 billion gallons of advanced biofuels by 2020 for us to obtain our 2.24 billion gallons. This needs to be incorporated into both the economic assessment of the rule and the technical feasibility of the rule package.

Compliance Scenarios

- CARB needs to account for the incremental cost of vehicle technologies assumed in some of the scenarios that go beyond what is required by the ZEV mandate (and even the ZEV mandate numbers are tenuous given the number of times the regulation has been modified over the years). This doesn't appear to have been accounted for, and for some of the technologies that ARB is looking at (fuel cells, plug-ins, etc.), it is hard to argue that they would arrive solely as a result of AB1493.

- Most compliance scenarios string together a series of assumptions and assertions without any apparent technological validity. Staff seems overly optimistic that the "right" fuels and vehicles will be available in the timeframes considered. We recommend ARB clearly outline all of the assumptions and assertions used in their analysis along with an assessment of how the compliance schedule could change if different scenarios are chosen.

- "Conventional" corn ethanol is assumed to be phased out between 2010 and 2015/2017 in favor of corn ethanol at 10% and 20% below CARBOB in carbon intensity. At the same time, federal requirements for corn ethanol continue at a very high level – 15 Bgpy.

  Given the bulk, if not all, of the corn ethanol under the federal RFS2 will be grandfathered into that program without regard for carbon intensity, it's difficult to see how ARB's assumptions will come to fruition without massive "shuffling" of any volume of low-CI corn ethanol that is available into California. Even in that case, ARB needs to provide some substantiation that sufficient volumes of such low-CI corn ethanol will exist to enable compliance.

- All gasoline scenarios rely on a fairly significant influx of "advanced technology" vehicles using hydrogen and electricity as fuel. Scenarios 1 and 2 assumed 560,000 by 2020; larger numbers are assumed for Scenario 3 (1 million) and Scenario 4 (2 million). The 560,000 is presumably based on the 2008 ZEV regulation.

  Given the ZEV regulation has been constantly altered since it was first adopted in 1990 to scale back the requirements in the absence of battery technology breakthroughs, how can ARB staff be certain that these vehicles will materialize? How can Scenarios 3 and 4 even remotely be considered technologically or economically feasible? This further supports the need for reviews every three years that take into account the reality of the situation at future points in time.

- Scenarios 1 and 2 assume 15.8 million gge of hydrogen in 2020; Scenario 3 assumes 24.8 million gge, and Scenario 4 assumes 49.6 million gge. What is the basis for these assumptions in terms of demand and the required infrastructure? What is the basis for the technological feasibility of these implementation rates? What is the cost-effectiveness of this approach to carbon control?

- The Diesel scenarios (5, 6, and 7) rely on significant volumes of advanced renewable diesel to meet the 2020 requirements. It is assumed that this fuel is derived from waste and has a carbon intensity of 20 g CO2e/MJ. What is this based on and what technology is envisioned to produce this fuel?

- Diesel Scenario 7 assumes introduction of plug-in hybrids to the heavy-duty fleet. What is the technological and economic feasibility of this approach? Again, the LCFS compliance pathway is dependent on technology innovation so it is essential ARB conduct progress and forecast reviews every three years.

95422. Applicable Standards for Alternative Fuels

- WSPA is concerned about the assignment of responsibility to the fuel provider to somehow be knowledgeable about a fuel's end use so as to make the choice of applicable standard (gasoline or diesel) clear to ARB. WSPA recommends ARB (including Enforcement Division personnel) hold further discussion with the industry on this point.

- On page 7 WSPA agrees it makes sense to have alternative fuels comply with the standard (gasoline/diesel) that the fuel will essentially replace (e.g., LDV/MDVs get gasoline; HDVs get diesel). However, will there be guidance in the regulation on how to allocate fuels that could go into both applications (e.g., natural gas)?

- WSPA reiterates our position that any fuel used to comply with the LCFS must meet all applicable local, state and federal standards for that fuel. If such standards do not exist they should be developed to ensure there are no issues with emissions, vehicle drivability, or materials compatibility.

- ARB's document does not address one of the critical issues that has not yet been resolved for biofuels and for future fuels – which is the lack of UL certification at the retail and possibly terminal levels.

95424. Requirements for Regulated Parties

<u>Regulated Parties/Point of Regulation</u>

- WSPA believes the LCFS regulations must create a level playing field between obligated parties and oxygenate and biodiesel producers. In addition, the LCFS regulations should not conflict with the U.S. EPA RFS regulations if possible. WSPA requests the proposed regulations should be changed so the LCFS obligation moves with title transfer of oxygenates and biodiesel if it has not already been blended into gasoline or diesel. This would be similar to the U.S. EPA RFS program where the RINs are attached to the renewable fuel until an obligated party or a oxygenate blender or a biodiesel blender takes title of the renewable fuel. The U.S. EPA had several reasons for setting up the RFS program in this manner, which are discussed in the preamble of the proposed rulemaking (Fed. Reg. Vol. 71, #184) of the RFS regulations. This change would directly encourage the purchase of low carbon fuels and discourage the purchase of high carbon fuels by the obligated parties and make the LCFS regulations more workable.

<u>WSPA recommends there be no separate treatment of parties that are producers or importers and parties that are non-producers or non-importers and that ARB treats all parties as producers or importers.</u> As with the transfer to a producer/importer the obligation should transfer to non-producer/non-importer unless the producer/importer agrees to retain the obligation via written notification. Moving the obligation downstream of the production/import facility if the fuel transfers title aligns the obligation with the ability of the regulated party to take action to comply. If ARB chooses to retain the distinction between producers/importers and non-producer/non-importer then WSPA suggests as an alternative that ARB revise the definition of producer and production facility in the LCFS regulations as described below.

"Producer" means any person who owns, leases, operates, controls or supervises a California production facility.

"Production facility" means a facility in California at which gasoline, diesel or CARBOB is produced or at which biodiesel is added to diesel.

While these changes in definitions may meet the objective it is not our preferred approach as we believe this may lead to confusion resulting from different definitions for producer and production facility in the proposed LCFS regulations and existing CBG regulations.

- Pg14. Section 95424 (a)(2)(B)(4) As with the transfer to a producer/importer the obligation should transfer unless the producer/importer agrees to retain the obligation via written notification.

- The point of compliance for natural gas and electricity lies with the entity responsible for the quality of the fuel. Within the liquid fuel market everyone shares in the responsibility for the quality of the fuel as it is moved downstream of the production or import facility. As such it is unclear where ARB intends to enforce the LCFS on such natural gas and electric fuel providers. ARB should be more specific on where exactly ARB would intend to enforce the LCFS on such fuel providers.

- Refiners use very efficient processes to produce electricity in their refineries. Often some of this electricity is provided to the grid and will likely be used in future ZEVs or plug-in hybrids. Is it possible for a refinery to be considered the fuel provider for part of their electricity if they meet the applicable LCFS requirements for other electricity providers?

- (D) Effect of Transfer by a Regulated Party of Gasoline to be Blended with Additional Oxygenate.

  The proposed rule appears to assume that the party transferring the gasoline knows whether or not the new owner plans to add additional oxygenate to it. This is not likely the case. We don't believe it is reasonable to impose additional requirements on the regulated party (transferor). This section needs to be revised to only address the party that chooses to buy gasoline and add additional oxygenate to it.

<u>Reporting Requirements</u>

- WSPA members are concerned with the proposed requirement for quarterly reports as required by section 95424(c)(3). Quarterly reports could be onerous and may be unnecessary. ARB needs to provide additional reasons for why such reports are necessary and why annual reports are not sufficient.

- (c)(3)(A)(1) Quarterly Reporting: Requires the regulated party to provide to the Executive Officer "…the product transfer document…". It would be helpful if ARB made it clear that what they want is the information from the product transfer document not a copy of the actual document.

- Clarification requested – are there implications in section 95423(c)(3) "Annual Compliance Reports" if third parties (such as brokers that do not hold title to credits) are involved in credit transactions and would they potentially have reporting requirements?

- Table 4 – We recommend deletion of unnecessary data reporting requirements (component blend data in particular). Also ARB needs to clarify how and if data can be kept business confidential.

- We do not understand why electricity seems to be given special treatment in Table 4. There are several categories such as feedstock information as well as production process where they do not have to supply any information.

- Need to specify fuels for Table 4 - it appears that under ARB's definition of blend stock, a refiner would be obligated to report the blend components in CARBOB. We have suggested the LCFS be consistent as possible with current CBG reporting requirements.

  Since the CI of CARBOB is based on an industry average we question the need for reporting such requirements. We therefore don't believe this is necessary and the definition of blend stock, for Table 4 only, should be adjusted to delete this requirement. ARB should specify that for Table 4, the blend stocks that make up CARBOB, CARB and CARB diesel need not be reported.

Determination of Compliance

- Violations and Penalties - WSPA supports a tiered structure but opposes the term non-compliance. This non-compliance provision is essentially a deficit carryover and should be defined as such, not as non-compliance.

- Several issues concerning enforcement have been discussed briefly by ARB but not resolved. For example, what level of accuracy will ARB need in order to enforce the LCFS standards, including the % reduction in CI as it relates to all the various fuels that will be subject to the LCFS.

  This needs to be part of the discussion before the LCFS rules are adopted not afterward. As such we encourage that future workshops deal with such enforcement issues specifically. WSPA has several issues concerning how ARB is enforcing its current rules that need to be included in this discussion.

95425. LCFS Credits and Deficits

- **Early credit generation**.
  In earlier drafts, ARB staff indicated regulated and exempted parties cannot generate LCFS credits from voluntary actions prior to 2010. It is assumed that encouraging early and real GHG emission reductions is an admirable goal and we hope ARB would support such actions if a viable and

enforceable means could be developed to regulate it. Now that the compliance schedule has been altered to contain just reporting in 2010 and intensity reductions starting in 2011, we believe there is increased opportunity for regulated parties to generate early credits for early action.

For illustrative purposes, some possible actions that a regulated or exempted party could take to create early credits might include:

- Contract for the delivery of sugar-cane ethanol instead of corn-based ethanol.
- Blending of biodiesel or renewable diesel in CARB ULSD; and,
- Increasing the amount of ethanol in gasoline where the ethanol has a lower CI than what had been used.

WSPA would like an opportunity to discuss possible early credit compliance processes with ARB.

- **Capping of Early Credits.**
  WSPA believes it is very important that ARB not limit the amount of credits any one party can generate and bank for future sales or use.

  In addition, ARB should not, as has been proposed, require regulated parties to divulge publicly detailed information regarding how many credits they have. Making such information public will likely have significant adverse impacts on parties seeking to buy and sell credits. For example, if a regulated party is substantially short credits and this were made public, it could result in the regulated party having to pay a much higher price for credits driving up the cost of compliance, and potentially the price of fuel to consumers.

  Likewise, there should be no discounting in the value of early credits**.**

- **Use of GHG Credits from Outside of the LCFS**.
  As worded in the draft regulation, it appears that actions taken to comply with any federal program including the Renewable Fuels Standards might not be allowed to be used to help a party comply with the LCFS. We hope this is not ARB's intention, and recommend the wording be clarified.

  For example, if a LCFS regulated party generates RINs under the RFS program for actions taken in California would those actions be allowed to be credited toward LCFS compliance? What if the party created excess RINs compared to the RFS requirements – can those credits be used for LCFS compliance?

- **Not Allowing Offsets from Non-regulated Fuels**.
  ARB is proposing that LCFS credits cannot be generated from fuels not subject to the LCFS (e.g. aviation fuels, certain marine fuels). We believe this is not a good policy decision. Fuel providers should be encouraged to look for voluntary actions outside of the regulated scope of the LCFS to generate GHG credits. We recommend ARB allow regulated parties to enter into agreements or protocols with ARB that would encourage technology development through the generation of LCFS credits. For example, this might include a refiner agreeing to use a renewable fuel blend in the ocean going vessels that operate in and out of California, or providing an aviation fuel that uses a renewable feedstock. ARB could use a process similar to the one above for generating early credits or allow for a Memorandum of Understanding under the proposed rules.

- **Disclosure of Credit Balances**
  We would be concerned if ARB required LCFS credit balances be made public as this could distort LCFS credit market issues.

- **Double Regulation**
  Clarification is needed concerning how refinery improvements that are made under AB-32 are reflected in the carbon intensities of gasoline and diesel. As with other fuels' improvement in fuel production, efficiency should be recognized in the LCFS.

- **Electricity Provider Credits**
  ARB proposes to give electricity providers a significant LCFS credit if they can show they provided electricity to motor vehicles due to the high efficiency of electric motors.

  We support several of ARB's proposed provisions as they apply to electricity.

- We support the proposal that electricity providers cannot estimate the electricity they provide but must provide some way to measure the electricity used in a motor vehicle.

- We support the diversification of fuel sources used in California.

WSPA has some questions and concerns as well:

- We understand electricity providers are required by law to supply the necessary electricity to meet their customers' needs. If so, why do they get any credit for providing something they are mandated to provide anyway? They are also required to meet the Renewable Portfolio Standards. AB 32 proposes they meet a 33% requirement by 2020.

- Why does providing a metering device allow utilities to get LCFS credits? ARB has argued that since they have to provide some type of metering devices it is appropriate to provide them the LCFS credit. Essentially all fuel suppliers provide some type of metering devices when refueling.

  If additional vehicles come on line that use diesel, gasoline, LPG, CNG or hydrogen – the fuel providers will all have to provide some type of additional metering devices at their own expense – and they are not assured that they will get any return on the money they invest in the infrastructure as will the utilities. We don't believe the utilities take much financial risk in providing such devices compared to private industry.

- Will the LCFS credit be adjusted downward to compensate for the RPS that utilities are required to meet? Will they only get credit if they exceed the RPS?

- In turn, will the LCFS credits they generate by providing electricity to vehicles be allowed to be used to comply with their RPS requirements as well?

- Many oil companies provide electricity to the grid. If oil/energy companies provide "metering devices" for electricity can they get credit too – up to the amount of electricity they provide to the grid?

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- In addition, auto companies are mandated to meet the Pavley GHG regulations. The GHG emission reductions from the use of ZEV's are captured under the Pavley rules. ARB has said they will have to adjust the AB 32 emission inventory to compensate for this double counting.

  No details on how that adjustment is planned have been provided. Can ARB provide us those details and the assumptions they made when making the estimate? In particular, what was the CI of the electricity used in refueling the vehicles, and, did ARB use the same CI in the Pavley Rules as it did for the LCFS?

- Finally, did ARB use the same CI for electricity when estimating the CI for other fuels that will be required to use incremental amounts of electricity under the LCFS?

95425. Determination of Carbon Intensity Values

Land Use Change

- It is paramount that ARB work with EPA to align on a methodology across state and national programs that is based on sound science rather than propose one approach versus another. It is possible that ultimately this issue needs to be resolved on a global basis to ensure a globally consistent and harmonized approach, to avoid unnecessary and nonproductive shuffling of biofuels.
- Regarding the Land Use Analysis chart (ARB staff presentation on 10/16- slides 21, 22) – a) did ARB consider cumulative impacts of any of these potential changes (it appears just high and low for each, holding others constant)?, and b) what analysis was done to determine the ranges chosen for the input variables?, and c) ARB's averaging approach assumes each scenario is equally probable - is this realistic?
- WSPA requests more details on the LUC numbers. How many acres of what type of land were converted for CBE (acres/100 gallons ethanol)? What are the effects of intensification on the efficiency of corn production and N2O conversion? Can ARB show these details in their backup document?

Indirect Land Use Change

To correctly account for all of the indirect effects resulting from an increase in ethanol production, ARB should factor in all of the resulting impacts, not just the change in land crop production. We question why ARB has not accounted for the effect of world wide intensification in their analysis. We point out the UC analysts called on ARB to include the effects of intensification.

WSPA requests that ARB evaluate potential net changes in GHG emissions from world-wide food production due to the phenomenon of intensification. If so, this incremental GHG impact should be assigned to the incremental ethanol production that would be the reason for these changes.

As another example of a factor that should be considered, the EPA in their evaluation included reductions in cattle production and subsequent reduction in emissions which ARB has chosen not to include in their scope. Given the critical nature of ILUC to the LCFS, we would recommend ARB perform the most thorough analysis possible.

Crude Oil

- WSPA requests more transparency in the Crude Recovery section in the CARBOB and ULSD pathways. In particular, it would be beneficial to disclose the individual Recovery Efficiency factors for the component crudes used to develop the weighted CA Recovery Average of 92.7%.

- WSPA continues to support the concept that all crude oil should be given the same average value. If ARB differentiates between crude it will only result in shuffling of crude oils to comply with the program and will certainly result in additional GHG emissions. As such, we reiterate our recommendation that all crudes be given the same average CI value.

Alternative Methods

- WSPA supports a practical opt-in process that is designed to encourage innovation to produce lower carbon intensity fuels. It should ease the burden on applicants to the extent possible, while providing the ARB with the assurance that accurate values are being generated.

- WSPA would like confrmation that ARB will not allow regulated parties to develop their own EERs.

- GREET contains forecasts of efficiency improvements for certain pathways, which implies that the carbon intensity changes over time. Will the default CARBOB intensity change with calendar year, or will it be static? How about the CI lookup table? Will those estimates be a function of calendar year or will they be static?

- Staff believes that GREET input values for industry average practices should be assumed for data that are difficult to obtain and report. Who decides what constitutes “difficult to obtain and report”? Who decides what goes into the “invariant data” list? ARB needs to explain the reasoning behind the concept of the invariant list since we do not support it at this time.
- Unrestricted public use of data submitted under an alternative method seems excessive and could potentially result in the disclosure of trade secrets or other competitively sensitive information. There should be a provision to keep competitively sensitive data confidential. We need additional details regarding the staff presentation on January 30 regarding this issue, as well as time for our membership to review.

95426. Requirements for Multimedia Evaluation

ARB should provide its legal analysis of the applicability of H&S section 43830.8 to ARB’s adoption of the LCFS regulation. This could avoid the question of how staff's proposed "functionally equivalent" LCFS multimedia assessment would work.

For example, will ARB be submitting it to the California Environmental Policy Council for their review? Why perform "real" multimedia assessments later if ARB is going to perform a "functionally equivalent" multimedia assessment upfront now?

In ARB’s "functionally equivalent" LCFS multimedia assessment:

a) How will ARB address emissions of all air pollutants, including ozone forming compounds, particulate matter, and toxic air contaminants as well as emissions of greenhouse gases resulting from each pathway?

b) How will ARB address potential contamination of surface water, groundwater, and soil resulting from each pathway?

c) How will ARB address disposal or use of the byproducts and waste materials from the production of the fuel resulting from each pathway?

Why not address these multimedia issues as much as possible up front to facilitate the implementation of the LCFS, lower its cost and avoid mistakes?

95427. Definitions

ARB is inappropriately using ASTM D6751 and D4608 in reference to B100 and E100 as finished fuels in the opening paragraph. Both of these specifications are for the use of each respective material as a blend stock to be added to a petroleum base, e.g. B5 and E10. They are totally inadequate as finished fuel specifications for either B100 or E100.

ARB needs to revise the use of "blend stock" for Table 4. We understand the intent but ARB should use a term such as "base fuel" instead of blend stock. This is important because, as written, producers would have to report volumes, carbon intensities, etc. of commodities (i.e. alkylate, reformate, butane, etc.) that are blended to make base fuels that may be subsequently blended with alternative fuels.

We recommend ARB use the term "base fuel" in Table 4 or state for Table 4 that blend stocks reported are not blend stocks that go into CARB, CARBOB, or CARB Diesel unless these blend stocks are actually added at the rack. For example, a regulated party would just report volumes of CARB, CARBOB, Ethanol and other renewable fuels, volumes of CARB diesel, E100, E85.

ARB's definition of "crude oil" includes GTL and CTL as "non-conventional" crudes. Our industry would consider these as products or blend stocks and not define them as "non-conventional" crude oils.

Section 95429. Regulation Review

The language offered at the January 30 workshop is woefully inadequate. WSPA feels very strongly that the LCFS regulation should require a periodic review on the order of every three years, not just one review in 2012.

In addition, we request the reviews be public processes, not just performed by the Executive Officer or ARB staff with no public input or review.

Third, we request that the regulation contain language specifying the scope and content of the reviews so there is no ambiguity in what the review is meant to cover. The reviews should evaluate the program's progress against the targets and make adjustments as necessary. Any economic and environmental issues that have arisen should also be analyzed. Some of the aspects that should be addressed in the periodic reviews are:

- any technology advances,
- an assessment of the supply and rate of commercialization of fuels and vehicles,
- the program's impact on the state's fuel supplies,
- the program's impact on state revenues and consumers, and,
- an identification of hurdles or barriers (i.e. permitting issues, research funds, etc) and recommendations for appropriate remedies.

It is important the periodic reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The periodic reviews should be conducted by key agencies and stakeholders including but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers.

APPENDIX A. (no longer Appendix A) Calculations of Energy Economy Ratios (EER)

WSPA submitted to ARB on February 4 a cover letter and a report by our contractor E.E.A. on the EERs.

APPENDIX B Carbon Intensity Look-up Table – Method 1

ARB lists CI values for "CARBOB average crude to CA refineries" and "ULSD average crude to CA refineries". Based on ARB's staff response to a question at the last workshop, can ARB clarify that these CI's are also to be used for imported CARBOB and ULSD. Does the same hold true for biodiesel and renewable diesel that may be imported into California or actually produced in California?

WSPA is concerned that changes made by ARB to their GREET model could result in a subsequent modification of their rules/regulations/standards without going through the public process which would appear to be a violation of the California Administrative Procedures Act. For example, we find it concerning that the numbers in Table B1 that was distributed at the January 30 workshop are different from the numbers posted for the pathways on ARB's website ten days prior. We do not understand why there are differences or how many more revisions are anticipated.

APPENDIX 1

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

To: California Air Resources Board

From: Judson Jaffe, Vice President, Analysis Group, Inc.

Date: December 17, 2008

Re: Comments on the Low-Carbon Fuel Standard Proposed Economic Analysis

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These comments briefly address three issues that CARB needs to consider carefully in performing its economic analysis of the Low-Carbon Fuel Standard (LCFS):

- Uncertainty
- The appropriate baseline against which to measure costs
- Alternative scenarios necessary to understand the cost of the LCFS

The economic impacts of the LCFS could be among the most significant of any element of CARB's AB 32 Scoping Plan. Moreover, it is possible that adjustments to the design of the LCFS could significantly reduce its cost and the economic risks that it poses. Therefore, sound and comprehensive economic analysis is immensely important in order to inform CARB's decisions in implementing the LCFS.

1. Uncertainty

Developments in transportation fuel markets over the past few months underscore the tremendous uncertainty associated with the cost of regulations such as the LCFS. While CARB's staff currently expects the cost of low-carbon fuels to be effectively comparable to that of conventional fuels, there is a substantial probability that this will not be the case. Changes in the cost of conventional fuels or in the cost of low-carbon fuels could easily alter the annual cost of meeting the LCFS target by billions of dollars.

Importantly, the implications of this uncertainty for the cost of the LCFS are not symmetric. If conventional fuels turn out to be less costly or if low-carbon fuels turn out to be more costly than anticipated, then the LCFS may be far more costly than CARB projects. On the other hand, if conventional fuels turn out to be more costly or if low-carbon fuels turn out to be less costly than anticipated, then the LCFS's target may be met *even without* the LCFS in place. That is, in this latter scenario, any "savings" associated with the use of low-carbon fuels may be realized regardless of whether or not the LCFS is implemented, such that the LCFS would have no incremental economic impact. As a result, the cost of the LCFS in the former scenario *will not be* counterbalanced by cost savings in the latter scenario.

In essence, the LCFS may require something that would occur anyway if low-carbon fuels turn out to be as inexpensive as (or even less expensive than) CARB anticipates. But, the LCFS may lock California in to the use of costly low-carbon fuels if CARB's projections turn out to be wrong. It is important for CARB to analyze the implications of this asymmetric risk for the "expected value" of the LCFS program's cost — that is, for the average cost of the LCFS program taking into account all possible future scenarios.

In assessing uncertainty, it is important that CARB evaluate the extent to which costs may differ from its primary projection, and the likelihood of such scenarios. This requires considering the underlying determinants of the cost of the LCFS (e.g., the cost of conventional and low-carbon fuels) and the uncertainty surrounding those determinants. CARB should present the findings from numerous scenarios that appropriately reflect the degree of uncertainty in these key determinants of the cost of the LCFS.

In response to peer review comments on its economic analysis of the Scoping Plan, CARB explored uncertainty in its estimates by simply *assuming* that costs and savings from the Scoping Plan might differ by particular arbitrary percentages from its primary projections. CARB did nothing to assess how likely such deviations would be, and whether deviations could be even greater than CARB assumed. Therefore, CARB's analysis did nothing to inform policymakers about the true economic risks associated with the particular regulations that it has proposed. Its analysis would be akin to evaluating the value of a corporate bond by *assuming* a particular likelihood of default, rather than by actually evaluating the likelihood of such a default based on the economic condition of the specific company in question.

LCFS places a rigid requirement on the transportation fuel market that could prove to be extremely costly under certain future scenarios if low-cost low-carbon fuels do not emerge in sufficient supply. Thus, a critical issue that CARB will need to address is whether to adopt particular cost-containment mechanisms and, if so, what kind of mechanisms it should adopt.[1] To help inform CARB's decisions with respect to these issues, it is important for an economic analysis of the LCFS to assess the likelihood of those scenarios in which costs are higher than expected, and to assess how much higher costs could be. To offer an analogy, one cannot make a reasoned decision about whether or not to purchase flood insurance without considering the likelihood of a flood and the extent of property damage that would be caused by such a flood. Likewise, CARB cannot make a reasoned decision about whether to adopt a cost-containment mechanism, and about the kind of mechanism to adopt, without a rigorous assessment of the uncertainties introduced by the LCFS.

2. The Appropriate Baseline Against Which to Measure Costs

A key issue in the measurement of the LCFS's economic impact is the determination of an appropriate baseline of how transportation fuel markets would evolve in the absence of the LCFS. In particular, it is critical that this baseline be consistent with CARB's projections of fuel prices. That is, if CARB believes that low-carbon fuels will be less costly than, or as costly as, conventional fuels even in the absence of the LCFS, the baseline should reflect that low-carbon fuels would be adopted even in the absence of the LCFS. Alternatively, if CARB does not believe this would be an appropriate baseline,

[1] CARB could adopt one or more of a variety of cost-containment mechanisms. As just one example, CARB could codify a periodic program review with clearly established conditions for making adjustments to program design and/or targets.

it needs to offer a rigorous assessment of why low-carbon fuels would not be adopted in the baseline even if they are less costly than conventional fuels.

As was mentioned above, if low-carbon fuels would be adopted in the baseline in the event that they are less costly than conventional fuels, this has critical implications for the cost of the LCFS. In such a case, the LCFS would have no economic impact if low-carbon fuels are less costly than conventional fuels, whereas it would lock California in to the use of costly fuels if low-carbon fuels turn out to be more costly than expected.

3. Alternative Scenarios Necessary to Understand the Cost of the LCFS

Assessing the cost of the LCFS relative to the business-as-usual baseline should be a key element of CARB's analysis. However, CARB should also measure the cost of the LCFS relative to at least two alternative scenarios: a less stringent carbon-intensity requirement, and achieving comparable emission reductions through an economy-wide cap-and-trade system.

It is my understanding that the specific carbon intensity required under the LCFS was not selected based on the result of an economic analysis. Therefore, both CARB and Californians should be made aware of the incremental cost of meeting that particular carbon-intensity target, relative to the cost of meeting slightly less stringent carbon-intensity targets. This is particularly relevant because it is difficult to argue that the transformative effect of the LCFS will be undermined if the LCFS requires, for example, a 9% reduction in the carbon-intensity of fuel rather than a 10% reduction. If slight adjustments to the carbon-intensity target can significantly affect the LCFS's cost without affecting its transformative impact on transportation fuel markets, both CARB and Californians more broadly should be made aware of that.

Similarly, even if the LCFS were not implemented, AB 32's 2020 emissions target would still be met as a result of the economy-wide cap-and-trade system that CARB is proposing to implement under the Scoping Plan. Therefore, CARB should evaluate the cost of implementing the LCFS relative to an alternative scenario in which LCFS is not implemented and the necessary emission reductions are achieved through the cap-and-trade program. While the LCFS clearly has policy objectives beyond just GHG reductions, given the ability to achieve the GHG reductions through reliance on the cap-and-trade system alone, CARB should understand the cost of achieving the LCFS's additional objectives.

Appendix 2 – Sierra Research Report – Preliminary Review of the CARB Staff Analysis of the Proposed Low Carbon Fuel Standard

Preliminary Review of the CARB Staff Analysis of the Proposed Low Carbon Fuel Standard (LCFS)

prepared by:
Thomas C. Austin
James M. Lyons
Frank DiGenova
Sierra Research, Inc.
April 8, 2009

CARB staff has performed an economic analysis for its proposed Low Carbon Fuel Standard (LCFS) concluding that adoption of the standard will result in a cost savings to California motorists of up to $3.4 billion per year by 2020 ($11 billion over the period from 2010 to 2020). The staff's emissions analysis also concludes that there will be a significant reduction in greenhouse gas (GHG) emissions and a net reduction in criteria pollutants. In contrast, as explained in more detail below, we estimate that fuel costs will increase by approximately $3.7 billion per year in 2020, oxides of nitrogen (NOx) emissions will increase by more than 5 tons per day, and there will be no detectable change in climate. It should also be noted that the estimates of alternative fuels costs, including our own, are based on paper studies that assume economies of scale yet to be demonstrated in practice. The economic analysis in the Initial Statement of Reasons[1] (ISOR) fails to account for the uncertainty associated with such studies. This is especially a concern given that a study[2] published subsequent to the preparation of the ISOR projects higher costs than earlier studies.

Specific problems with the ISOR include the following:

1. Only the low end of the baseline costs for conventional fuels (which CARB staff did not use in its economic analysis) is consistent with historical oil price trends. As a result, the economic analysis assumes future costs for conventional fuels that are too high, which contributes to an underestimate of the costs of LCFS fuels by over one billion dollars per year.

2. Cost estimates for alternative fuels are unrealistically low due in part to unrealistic estimates for feedstock cost, unrealistic estimates of the cost of emissions control requirements on biomass refineries, and unrealistic assumptions regarding the cost of capital—the combination of these factors leads CARB staff to underestimate the cost of the LCFS by over two billion dollars per year.

3. The ISOR assumes that the federal $1.01 per gallon tax credit for cellulosic ethanol scheduled to expire at the end of 2012 will be extended indefinitely and subtracts this tax credit from the net cost. Similarly, the ISOR assumed that the federal $1.00 per gallon tax credit for biodiesel scheduled to expire at the end of 2009 will be extended indefinitely and subtracts this tax credit from the net cost.

[1] "Staff Report: Initial Statement Of Reasons, Proposed Regulation To Implement The Low Carbon Fuel Standard," California Air Resources Board, Stationary Source Division, March 5, 2009.
[2] D. Hsu, "Techno-economic comparison of biochemical, gasification, and pyrolysis conversion of corn stover to biofuels," National Renewable Energy Laboratory, March 20, 2009.

4. In addition to assuming that low carbon intensity biofuels will be available in large quantities with federally subsidized costs below those for gasoline and Diesel fuels, CARB staff assumes that grid electricity and, to a lesser extent, hydrogen will be available as transportation fuels in California at costs below those for gasoline and Diesel fuels. To support this assumption, CARB staff credits electric and fuel cell vehicles with greater efficiencies than appear warranted based on previous agency assessments, and not only ignores the incremental costs of these vehicles but also in some cases assumes that they will be produced in numbers far greater than required by the current Zero Emission Vehicle (ZEV) regulation. Depending on the compliance scenario, these incremental costs range from about $14 billion to $47 billion over the period 2010 to 2020, as compared to the staff's claimed $11 billion cost savings for the LCFS.
5. Contrary to the conclusions of the ISOR, implementation of the proposed LCFS would cause an increase in criteria pollutant emissions of at least 5 tons/day and perhaps more, given that the staff has not performed any realistic assessments of how its assumed volumes of electric and fuel cell vehicles impact the Low Emission Vehicle, ZEV, and Pavley regulations. Another consequence of this latter fact is that CARB staff may be overestimating the greenhouse gas reductions achieved in the transportation sector by the combination of the Pavley and LCFS regulations. In any case, the increase in criteria pollutants is not counterbalanced by any measurable effect on climate.

The Baseline Fuel Price Should Be at the Low End of CARB's Range

As stated in the ISOR, "staff used forecasts of prices for crude, gasoline, and diesel that are included in the Energy Commission's document 'Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report (IEPR).' To be consistent with the assumptions used in preparing the AB 32 Scoping Plan, approved by the Board in December 2008, staff used the 'high case' values in the report." As shown in a detailed table, the assumed range of oil prices was $66-88 per barrel, which was translated into gasoline prices of $2.42 to $2.92 per gallon, excluding all state and federal taxes. The corresponding range for Diesel prices is $2.48 to $2.99 per gallon.

Staff acknowledges that "the economic analysis of the LCFS is greatly affected by future oil prices" and that economic factors that might keep crude oil prices lower than the prices used in the forecast "could result in overall net costs, not savings, for the LCFS. For the reasons set forth below, we consider that the low end of the range considered in the ISOR (i.e., $2.42 per gallon for gasoline and $2.48 per gallon for Diesel) is more consistent with what would be expected based on long-term oil price trends.

For purposes of this report, we accept the assumed relationship between crude oil prices and gasoline prices used by the staff. We believe, however, that it is more realistic that the low end of assumed crude oil prices, i.e., $66 per barrel, should be used for the entire period through 2020.

As noted in the ISOR, there have been recent changes in the estimates of future oil prices by the U.S. Energy Information Administration (EIA) and the California Energy Commission. However, government forecasts of oil prices have been notoriously inaccurate ever since the first oil embargo in 1973. Following every event that causes a spike in oil prices, government forecasts are changed to show dramatically higher prices for the longer term. Every time this occurs, the higher price forecasts end up being shown to be an over-reaction. Extraction technology continues to improve, the economically feasible resource base grows, and the long-term cost of oil ends up being lower than the forecasts made following price spikes.

EIA acknowledges that, since 1982, it has overestimated future oil prices by 59% on average.[3] Shortly after the oil price spike in 1980, the forecast for the price of oil in 1995 ended up being high by 492.7%. Forecasts made since the most recent oil price spike have already demonstrated the same pattern of overestimation. As a result, gasoline prices based on a $66 per barrel oil price are a more reasonable benchmark for the future than any higher oil price forecast. Based on historical trends, actual prices may be lower.

Using CARB's estimate for gasoline prices when oil is $66 per barrel, <u>the baseline fuel prices, excluding taxes, are $2.42 per gallon for gasoline and $2.48 per gallon for Diesel.</u>

<u>Costs for Low Carbon Fuels</u>

Although cost estimates are provided in the ISOR for several alternative fuels, it is clear that cellulosic ethanol is the key alternative for demonstrating compliance with the LCFS. (The infeasibility of greater reliance on so-called "zero emission vehicle" technologies under staff scenarios 3 and 4 is discussed below.) Our critique is focused on scenario number 1, which assumes the maximum use of cellulosic ethanol.

ISOR estimates for cellulosic ethanol range from $2.31 to $3.74 per gasoline gallon equivalent (gge), excluding taxes. The low end of this range is below our estimate of the baseline gasoline price; however, the $2.31 per gge estimate assumes the feedstock is municipal waste with a feedstock cost of $0.00. At the volumes required to comply with the federal Renewable Fuel Standard and the proposed regulation, the primary feedstocks will need to be forest residue, agricultural residue, and herbaceous crops (e.g., switchgrass). Assuming such feedstocks, the ISOR estimates range from $2.70 to $3.74 per gge. The low end of this spectrum exceeds our estimate of the baseline gasoline price by $0.28 per gge. However, our independent analysis of cellulosic ethanol cost indicates that actual cost will be higher than estimated in the ISOR.

The key elements of cost occur in the following categories:

1. Feedstock (and associated transportation);
2. Amortization of capital equipment required for feedstock conversion;
3. Operating costs for feedstock conversion; and
4. Distribution and marketing costs.

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[3] "Annual Energy Outlook, Retrospective Review: Evaluation of Projections in Past Editions (1982-2008)," U.S. Department of Energy Report No. DOE/EIA-06403(2008), September 2008.

Feedstock Costs – Assuming wood chips are the feedstock for cellulosic ethanol, the ISOR lists the feedstock cost at $29/dry ton based on a 2008 study by the National Renewable Energy Laboratory (NREL). Detailed tables in the ISOR identify municipal solid waste (MSW) as the primary feedstock for biorefineries assumed to be located in urban areas and the cost for MSW is listed as $0.00 per dry ton. However, there is also this statement in the section of the ISOR identifying common assumptions:

> *Wood chips, green waste, and corn stover are the common feedstock sources for both cellulosic and advanced renewable ethanol fuels.*

As described in more detail below, there are serious questions as to whether a biorefinery can be constructed in urban areas (especially Southern California) given the limited availability of emissions offsets for new sources and the issues associated with relatively high volumes of truck traffic. Also, the additional processing required for using "free" MSW adds uncertainty to the total system cost. We have therefore independently estimated the cost of cellulosic ethanol based on the assumption that the feedstock would be a more consistent source of cellulosic or ligno-cellulosic feedstock. (This is consistent with the assumption regarding feedstocks stated in the ISOR.)

The recent Sandia/GM study[4] identified biomass feedstock cost at $40 per ton at the farm, not including the cost of transportation to the production facility. Estimating delivered feedstock cost at $49/ton, feedstock costs would be $0.73 gallon of ethanol, which is $1.08 per gge. This estimate was made by adjusting the feedstock cost in another NREL study[5] cited in the ISOR to account for a $49/ton delivered price.

Amortization of Capital Investments – As stated in the ISOR, "staff used a capital recovery factor of 14.90 percent, based on an eight percent real discount rate per year with a capital recovery period of 10 years." This is an extremely optimistic capital recovery factor for technology that has never been demonstrated in commercial scale and for which there are serious questions about economic feasibility. Although it is stated that the capital recovery factor is "intended to reflect the risk in investing in new biorefinery technologies," it clearly does not reflect that risk. An average venture capital return rate exceeds 20%.[6]

The ISOR estimates a capital investment for ethanol produced from ligno-cellulose at $309.7 million for a 50 million gallon per year production facility. This estimate is based on the capital cost in a previously referenced NREL study,[7] adjusted to reflect changes in the consumer price index. However, a more recent NREL study estimates the capital cost for a similarly sized facility at $376 million.[8] (The recent NREL study focuses on corn

[4] "90-Billion Gallon Biofuel Deployment Study," Sandia National Laboratories, February 2009.
[5] R. Wooley, et al., "Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios," National Renewable Energy Laboratory Report No. NREL/TP-580-26157, July 1999.
[6] Joseph W. Bartlett, "Venture Capital: A Primer," e-Journal USA, U.S. Department of State, Volume 13, No. 5, May 2008.
[7] R. Wooley, et al., op. cit.
[8] D. Hsu, op. cit.

stover rather than wood chips; however, NREL's previous studies have shown the capital cost for facilities using corn stover to be slightly lower.) At $309.7 million for 50 million gallons per year, the assumed 8% discount rate and 10-year amortization assumed in the ISOR produces a capital recovery cost of $1.37 per gge. In addition to not reflecting a more current capital cost estimate, this estimate does not account for the cost of compliance with local air pollution control district regulations. The emissions compliance cost used in the ISOR is totally unrealistic.

For cellulosic ethanol production facilities, the process heat requirements are higher than they are for existing facilities that produce ethanol from corn. To minimize costs, the design of commercial-scale production facilities assumes combustion of biomass feedstock to generate the necessary heat and electric power. Based on the above-referenced NREL study, heat input required for a 50 million gallon per year facility using ligno-cellulosic feedstock is 931 million BTU/hour.

The ISOR assumes that Selective Catalytic Reduction (SCR) systems will be used to reduce NOx emissions by 90%. However, 90% efficient SCR systems have not been demonstrated to be commercially feasible with biomass combustion due to the catalyst fouling problems caused by the high particulate concentrations in the combustion products and variations in biomass fuel. Seven biomass-fired boilers have recently been permitted with 80% efficient SCR systems in the state of Ohio. With the SCR system, NOx emissions from the boilers are estimated to be 0.09 lbs per million BTU. Assuming 8,000 hours of annual operation, this generates 335 tons per year of NOx emissions at a facility with a 931 MMBTU/hour heat input rate. At current offset costs (which are expected to increase over time), $18.4 million would be required to purchase offsets for facilities located in the Central Valley.[9] (In the South Coast Air Basin, the offset costs would be more than twice this amount, assuming the rules were changed to give biorefineries access to the "priority reserve" of NOx offsets.) Based on our independent analysis,[10] an additional $4.3 million is required to cover the cost of the SCR system. Ignoring permit fees, the air pollution control requirements increase NREL's most recent capital cost estimate for a 50 million gallon per year facility to $399 million. Assuming a very conservative 10% discount rate to recover the capital investment over the same 10-year period assumed in the ISOR, the amortization costs translates to $1.30 per gallon of ethanol, which is $1.94 per gge.

<u>Operating Costs</u> **–** The ISOR assumes a $0.66 per gge cost for the operating costs of a cellulosic ethanol production facility using wood chips for feedstock, based on the above-referenced NREL study. Our independent analysis of operating cost estimates in the 1999 NREL study produces a similar result. The results of the most recent NREL study reflect a substantially higher operating cost than NREL's earlier estimates for the same feedstock. However, because the most recent study assumes corn stover as the feedstock rather than wood chips, we are using the less expensive production cost derived from the 1999 study.

[9] Calculated based on a NOx offset cost of $55,000 per ton/year and a 1.5 offset ratio.
[10] Personal communication with Tom Andrews, Sierra Research, Inc., March 19, 2009.

One subcategory of operating cost for some alternatives is co-product credit. For its lowest-cost cellulosic ethanol scenario, the ISOR assumes a co-product credit of $0.14 per gge, presumably to account for the value of surplus electricity generated from the biomass combustion. Our independent analysis produced an almost identical value for the co-generated electricity at a biomass-fueled facility. With the co-product credit, the net operating cost is $0.52 per gge.

Distribution and Marketing Costs – The ISOR estimates the storage, transport, and distribution cost for cellulosic ethanol produced in California at $0.34 per gge, which is the same cost assigned to storage transportation and distribution of corn-based ethanol from the Midwest. In describing the rationale for this cost for ethanol produced in-state, the ISOR states that the cost for shipping ethanol from Northern California to Southern California is estimated at $0.20 to $0.30 per gallon. This seems to be inconsistent with the assumption that all ethanol production facilities are going to be located close to the point of end use. It is also clear from the detail provided that the storage, transport, and distribution category does not cover any markup/profit for the retailer that eventually sells the finished product.

Based our previous analysis of EIA gasoline price data, the per-gallon cost of distributing gasoline to retail outlets is $0.18 when oil is $66/bbl. Adjusting for energy density, this would translate to $0.27 per gge for ethanol. Considering the extra transportation distance required for ethanol, the $0.34 per gge cost estimate for storage, transport, and distribution does not appear to be unreasonable. However, an additional $0.10 per gge must be added to account for profit at the retail level, which was ignored in the ISOR. This brings the total cost for storage, transport, and distribution to $0.44 per gge.

As shown in Table 1, our estimate for the net cost, excluding taxes, of cellulosic ethanol is $3.98 per gge, which exceeds the estimated baseline fuel cost by 64%. With approximately 3 billion gallons of ethanol required in fuel for gasoline vehicles, the annual cost increase to California motorists is approximately $3.1 billion.[11] This is the cost only for the gasoline portion of the regulation. (This reflects the cost of all required ethanol, some of which would be required under the federal RFS.)

Table 1
Cellulosic Ethanol vs. Gasoline Cost
(Cost per Gasoline Gallon Equivalent)

Cost Category	ISOR Ethanol	Sierra Ethanol	Gasoline[a]
Feedstock	$0.47	$1.08	-
Capital Amortization	$1.37	$1.94	-
Production	$0.66	$0.66	-
Co-Product	-$0.14	-$0.14	-
Distribution and Marketing	$0.34	$0.44	-
TOTAL, excluding taxes	**$2.70**	**$3.98**	**$2.42**

[a] CARB estimate at $66/bbl crude cost.

[11] Calculated by multiplying 67% of the difference in cost per gge by 3 billion to account for the increased cost over using the baseline gasoline to provide the same amount of energy.

As described above, there are several differences between our independent cost estimates for cellulosic ethanol and those contained in the ISOR related to feedstock, refining, and marketing and distribution. However, more significant differences result from the assumptions used in the ISOR regarding tax credits and the allocation of certain capital costs.

According to the ISOR, tax incentives are provided for biofuels "in order to assist the US with improving energy independence and security and with improving the environment." According to the ISOR (Vol 1, pp VIII-8 to -9):

> *Staff reduced the overall cost of production of the lower-CI fuels…by the amount of the tax incentives, where applicable. The credits are assessed on a gallon of ethanol or biodiesel blended or produced and on the volume of CNG sold. <u>Although some incentives could expire in the near future, staff assumed the incentives would be extended</u>, as has been the case with incentives that had recently expired.* (emphasis added)

More specifically, the ISOR analysis has assumed, with no supporting justification, that the $1.01/gal tax credit for new cellulosic biofuels that was established by the 2008 Farm Bill—which took effect on January 1, 2009, and is set to expire on December 31, 2012—will be extended at least through 2020. Similarly, for ethanol and biodiesel blenders, the ISOR states:

> *As of January 1, 2005, the federal tax credit was $0.51 per gallon of pure ethanol blended, $1.00 per gallon of agricultural biodiesel (derived from virgin oils), and $0.50 per gallon of 'waste grease' biodiesel (derived from vegetable oils and animal fats). The Food Conservation and Energy Security Act of 2008 (2008 Farm Bill) reduced the ethanol credit to $0.45 per gallon of ethanol blended, effective January 1, 2009. The Emergency Economic Stabilization Act of 2008 eliminated the disparity in credit for biodiesel and agri-biodiesel (now providing $1.00 per gallon of biodiesel blended), and extended the credit through the end of 2009.*

In the final analysis of how the proposed regulation will affect the cost of fuel, the subsidies assumed to continue beyond current expiration dates are not treated as costs. If they were, the net cost of the LCFS would be positive, not zero or negative as claimed by CARB staff. In addition, the final cost analysis in the ISOR excludes certain costs that are claimed to be associated with the federal RFS, as described below.

> *The total potential capital cost of the proposed LCFS regulation—in the absence of the overlapping RFS2 requirements—is estimated at $10 billion over the next decade. However, if the RFS2 mandates are met and California receives its proportional share of RFS2 fuel, virtually all of the capital costs associated with the liquid fuels (ethanol and alternative diesel) would be borne by RFS2, not the LCFS. These would include the biorefineries, the ethanol storage tanks, and the E85 dispensers.*

As explained above, the ISOR seems to be suggesting that the federal Renewable Fuel Standard will result in the construction of greater biorefinery capacity than is required for compliance. This would be an economically irrational outcome for which we can see no conceivable explanation.

Biodiesel Cost – The production of biodiesel fuel (methyl esters) using soybeans is an energy efficient process but it is very expensive because of the high feedstock cost and the potential for extending fuel supplies is extremely limited. The International Energy Agency (IEA) has estimated that 60% of U.S. soy production (most of which is currently used for food and feed production) would be needed just to displace 5% of Diesel fuel demand.[12] As noted in the ISOR, biodiesel produced from waste vegetable oils avoids the high feedstock cost, but supplies of waste oils are so limited that the price of the volumes required under the proposed LCFS will not be significantly affected by the use of waste oil feedstock.

As shown in Table VIII-8 of the ISOR, the feedstock cost for biodiesel alone is estimated to be $2.62 per gallon of fuel produced, which already exceeds our $2.48 per gallon baseline cost estimate. When other cost factors are accounted for, the ISOR estimates the total price for biodiesel at $3.15 per gallon. With another 3% added to account for profit at retail, the total cost, excluding taxes, is $3.24 per gallon, 31% higher than the price of the baseline fuel. Assuming 838 million gallons are required for compliance, the cost increase to motorists is $637 million per year.

Additional Details Regarding the ISOR Cost Analysis

As described above, the analysis of the net cost contained in the ISOR is driven more by the assumptions regarding tax credits for low carbon intensity ethanol and biodiesel than by differences in the estimated costs of fuel production. However, another important factor for several of the gasoline and Diesel scenarios examined by CARB staff is the assumed cost of electricity and hydrogen, the assumed cost of electric and fuel cell vehicles, and CARB's assumptions regarding their efficiency relative to gasoline vehicles.

Energy Economy Ratios for Electric and Fuel Cell Vehicles Relative to Gasoline – The proposed LCFS regulations purport to account for the greater efficiency of electric and fuel cell vehicles relative to gasoline vehicles through the use of the energy economy ratios (EERs). Conceptually, the EERs represent the ratio of the miles traveled by an electric or fuel cell vehicle using a given quantity of energy compared to the miles that a gasoline vehicle would travel using that same quantity of energy. In the economic analysis, application of these factors reduces the effective cost of electricity and hydrogen used as gasoline substitutes. According to Appendix C-1 of the ISOR, the EERs of 3 for battery-electric vehicles and 2.3 for fuel cell vehicles are based on very limited comparisons between what the ISOR purports to be comparable vehicles, with some attempt made to account for future increases in the fuel economy of the gasoline vehicles.

[12] "Biofuels for Transport, An International Perspective," International Energy Agency, 2004.

The EER values for electric and fuel cell vehicles in the LCFS analysis are inconsistent with the treatment of these exact technologies under the Pavley regulations (Section 1961, Title 13, California Code of Regulations). The Pavley regulations set standards for greenhouse gas emissions from new vehicles and one can simply estimate EERs for electric and fuel cell vehicles from these standards and emission factors assigned by the regulations to electric and fuel cell vehicles. For example, for purposes of the Pavley regulations, all electric vehicles are assigned an emission rate of 130 grams of CO_2 equivalent emissions per mile while all fuel cell vehicles are assigned a value of 210 grams per mile. Standards for passenger cars are 301 grams per mile for the 2010 model year and 205 grams per mile for the 2016 model year. These values would indicate that the EER for electric vehicles should change over time and start at about 2.3 for 2010 model year vehicles and decrease to 1.6 for 2016 model year vehicles. In either case, the value is far lower than the 3.0 in the proposed LCFS regulations. Similarly, the EER for hydrogen vehicles would decrease over time from 1.43 in the 2010 model year to 0.98 for the 2016 model year.

As noted above, use of lower EERs like those that are effectively imposed by the Pavley regulations would increase the estimated cost of the LCFS regulation in the gasoline substitution scenarios and decrease the estimated reductions in greenhouse gases emissions. Conversely, substitution of the EERs from the LCFS in the Pavley regulation would greatly reduce the effective CO_2 emission rates for electric and fuel cell vehicles and decrease the degree to which manufacturers would have to improve the fuel efficiency of other vehicles in order to comply with the Pavley standards. In any case, there is no rationale as to why these vehicles are assumed to have different greenhouse gas emission rates from one CARB regulation to the next.

In addition to the EER values of 3 and 2.3 for electric and fuel cell light-duty vehicles, the LCFS also proposes EER values of 2.7 and 1.9 for electric and fuel cell heavy-duty vehicles, respectively. Again, these values are based on limited data.

As a result of the EERs assumed for electric and fuel cell vehicles, the costs assumed for electricity and hydrogen by CARB staff translate to \$1.00 and \$2.83 per gge, respectively, both of which are lower than the \$2.92 assumed for gasoline in 2020. In particular, the cost differential for electricity contributes significantly to the cost savings staff claims for the LCFS, especially for those scenarios where high volumes of plug-in hybrid vehicles (PHEVs) and battery electric vehicles (BEVs) are assumed.

Costs for Specialized Vehicles – The economic analysis in the ISOR for the proposed LCFS regulation assumes that substantial numbers of light-duty PHEVs, BEVs, and fuel cell vehicles (FCVs) will be sold in California at volumes at least equivalent to those required by the current ZEV regulations and at far higher volumes in some scenarios.

The ZEV regulations were originally adopted in 1990 and required BEV sales beginning with the 1998 model year. The regulations have since been changed numerous times in order to delay production requirements for BEVs due their high cost and limited performance relative to conventional vehicles. The latest assessments of battery and fuel cell technology indicate that these problems with cost and performance will continue into the future and suggest that additional changes to the ZEV regulations to delay production requirements will continue to occur. Again, because of the high cost of batteries, PHEVs are also considerably more expensive than conventional gasoline vehicles. The actual price premiums expected for these vehicles generally exceed the lifetime fuel cost for a 30 mpg gasoline vehicle. For example, when taxes are added to the baseline gasoline price, gasoline costs approximately $3 per gallon. In 150,000 miles, a vehicle averaging 30 mpg consumes 5,000 gallons of gasoline. The total fuel cost is $15,000. Assuming this cost is incurred over a period of 12 years at a uniform rate, the present value of the fuel cost is $9,400 using a discount rate of 8%. As shown below, this is substantially less than the price premium for either a BEV or an FCV before even accounting for the fuel costs for these vehicles.

Ultimately, the price premium for PHEVs, BEVs, and FCVs, combined with the limited driving range of the latter two and the lack of refueling infrastructure, makes them commercially infeasible for anything other than niche markets that cannot absorb the volumes of these vehicles required under the current ZEV regulations. Given this, the ISOR assumptions in the LCFS regarding the volumes of PHEVs, BEVs, and FCVs that will be in operation in the 2011 to 2020 time frame are unrealistic. We would also note that, despite the almost 20 years that have passed since the first adoption of the ZEV mandate, the regulation has never resulted in the production or sale of meaningful numbers of ZEV vehicles. Therefore, although CARB staff assumes that the current ZEV regulation will be implemented and that manufacturers will comply, there is no reason to believe that, when faced with the fact that ZEVs are still not feasible, a future Board will not again modify the regulation to postpone the date at which significant numbers of ZEVs are required.

In addition to the PHEVs, BEVs, and FCVs, the ISOR assumes there will be large increases in the number of flexible fueled vehicles (FFVs) sold in future model years and that those vehicles will operate exclusively on E85. Should the assumption of exclusive operation on E85 not be correct, the ISOR states that the effect can easily be offset through the sale of even greater numbers of FFVs. As with staff's assumptions regarding electric and fuel cell vehicles, there are a number of problems with the staff's assumptions regarding FFVs. First, although FFVs are currently produced by a number of manufacturers, FFV production is not required under any current CARB regulation. The primary motivation for those manufacturers currently producing FFVs is that federal law provides limited credits that can be used towards compliance with Corporate Average Fuel Economy (CAFE) standards. Not all manufacturers have sought such credits, however, and those manufacturers that have done so have limited the number of FFV models they produce because of the limits on the available CAFE credits; in addition, with the enactment of the Energy Independence and Security Act of 2007, the credits that are available to FFVs will be phased out over the 2015 to 2020 model years, eliminating any incentive manufacturers have to produce FFVs. Given the above, there is no reasonable basis upon which to conclude that the large volumes of FFVs assumed by CARB staff will be produced.

Another issue associated with FFV certification in California during future model years is that CARB's ZEV regulations require manufacturers to certify large volumes of new vehicles as "Partial Zero Emission Vehicles" (PZEVs), which means they must comply with Super-Ultra-Low Emission Vehicle (SULEV) exhaust emission standards, 150,000-mile emission warranty requirements, and Zero Evaporative Emissions standards. Such compliance is proving very difficult for vehicle manufacturers[13] and we are not aware of any FFV that has been certified as a PZEV to date.

Although it appears to be highly unlikely that the volumes of FFVs, PHEVs, BEVs, and FCVs assumed in the ISOR economic analysis will actually be sold in California during the period from 2010 through 2020, it is instructive to examine the assumed volumes and to note that all four of these vehicles cost more than conventional vehicles.

The volumes of FFVs, PHEVs, BEVs, and FCVs assumed can be found in Appendix E of the ISOR. The volumes are reported in terms of millions of each type of vehicle assumed to be in operation in California in any given year. The incremental volume of each type of vehicle required to enter the California vehicle fleet each year over the period from 2011 to 2020 can be computed by subtracting the number of vehicles of a given type assumed to be in the fleet in a given year from the value for the previous year. Most of the specialized vehicles assumed in the economic analysis enter the fleet during the 2015 to 2020 period. Table 4 summarizes by vehicle type the number of specialized vehicles assumed to enter the California fleet each year for each of the five gasoline scenarios. These numbers are translated into the percentage of total vehicle sales each year in California in Table 5 based on an assumption of annual light-duty vehicle sales of 1.5 million units per year. At the bottom of each table, “SUM” is the combined total of FFVs, PHEVs, BEVs, and FCVs for each scenario.

As shown in the tables, by 2018 to 2020, CARB staff assumes that FFVs account for more than 50% of vehicles sold in California under four of the five scenarios despite the fact that federal CAFE credits will have been dramatically reduced or eliminated by that time. In contrast to estimates of up to one million FFVs per year in the ISOR (Table F6-1), estimated FFV sales for 2009 (when substantial CAFE credits are available) is less than 350,000.[14] Similarly, PHEV, BEV, and FCV sales volumes and fractions assumed by CARB staff also are unreasonably high given that virtually none of these vehicles are sold today in California and their costs are exorbitant.

As noted above, the ISOR economic analysis ignores the incremental costs associated with specialized vehicles when calculating the net cost of the LCFS. With respect to FFVs, page 48 of Appendix F of the LCFS ISOR indicates that the marginal cost of producing FFVs is $200 per vehicle. No basis for that estimate is provided, however, and it does not appear to include costs associated with the changes required to certify FFVs as PZEVs.

[13] See, for example, “Fuel Economy & Emissions: Ethanol Blends vs Gasoline” presented by Kevin Cullen of General Motors, September 10, 2007.
[14] Herwick, G., “Opportunities for E85 in California,” presented to California Air Resources Board Meeting on Vapor Recovery for E85 Facilities, February 2, 2006.

Table 4
Annual Sales of FFVs, PHEVs, BEVs, and FCVs Assumed by CARB Staff

Vehicle Type	Scenario	Year 2015	2016	2017	2018	2019	2020
FFV	1	100,000	300,000	400,000	700,000	600,000	900,000
	2	100,000	300,000	400,000	800,000	800,000	1,000,000
	3	200,000	200,000	300,000	400,000	700,000	900,000
	4	0	0	100,000	500,000	500,000	700,000
	5	230,000	250,000	340,000	410,000	600,000	780,000
PHEV	1	40,000	40,000	50,000	70,000	70,000	60,000
	2	40,000	40,000	50,000	70,000	70,000	60,000
	3	80,000	70,000	80,000	80,000	140,000	150,000
	4	160,000	140,000	160,000	160,000	300,000	280,000
	5	80,000	70,000	80,000	80,000	140,000	150,000
BEV	1	11,000	10,000	10,000	5,000	25,000	20,000
	2	11,000	10,000	10,000	5,000	25,000	20,000
	3	20,000	25,000	29,000	35,000	40,000	60,000
	4	40,000	60,000	48,000	70,000	100,000	100,000
	5	20,000	25,000	29,000	35,000	40,000	60,000
FCV	1	6,000	5,000	5,000	17,000	18,000	15,000
	2	6,000	5,000	5,000	17,000	18,000	15,000
	3	10,000	12,500	15,000	18,000	20,000	32,000
	4	20,000	25,000	30,000	36,000	49,000	55,000
	5	10,000	12,500	15,000	18,000	20,000	32,000
SUM[a]	1	157,000	355,000	465,000	792,000	713,000	995,000
	2	157,000	355,000	465,000	892,000	913,000	1,095,000
	3	310,000	307,500	424,000	533,000	900,000	1,142,000
	4	220,000	225,000	338,000	766,000	949,000	1,135,000
	5	340,000	357,500	464,000	543,000	800,000	1,022,000

[a] The combined total of FFVs, PHEVs, BEVs, and FCVs.

Table 5
Annual Sales of FFVs, PHEVs, BEVs, and FCVs Assumed by CARB Staff in Terms of Percent of New Vehicle Sales (Based on 1.5 Million Total Sales Per Year)

Vehicle Type	Scenario	Year 2015	2016	2017	2018	2019	2020
FFV	1	6.7	20.0	26.7	46.7	40.0	60.0
	2	6.7	20.0	26.7	53.3	53.3	66.7
	3	13.3	13.3	20.0	26.7	46.7	60.0
	4	0	0	6.7	33.3	33.3	46.7
	5	15.3	16.7	22.7	27.3	40.0	52.0
PHEV	1	2.7	2.7	3.3	4.7	4.7	4.0
	2	2.7	2.7	3.3	4.7	4.7	4.0
	3	5.3	4.7	5.3	5.3	9.3	10.0
	4	10.7	9.3	10.7	10.7	20.0	18.7
	5	5.3	4.7	5.3	5.3	9.3	10.0
BEV	1	0.7	0.7	0.7	0.3	1.7	1.3
	2	0.7	0.7	0.7	0.3	1.7	1.3
	3	1.3	1.9	1.9	2.3	2.7	4.0
	4	2.7	4.0	3.2	4.7	6.7	6.7
	5	1.3	1.7	1.9	2.3	2.7	4.0
FCV	1	0.4	0.3	0.3	1.1	1.2	1.0
	2	0.4	0.3	0.3	1.1	1.2	1.0
	3	0.7	0.8	1.0	1.2	1.3	2.1
	4	1.3	1.7	2.0	2.4	3.3	3.7
	5	0.7	0.8	1.0	1.2	1.3	2.1
SUM[a]	1	10.5	23.7	31	52.8	47.6	66.3
	2	10.5	23.7	31	59.4	60.9	73.0
	3	20.6	20.7	28.2	35.5	60	76.1
	4	14.7	15.0	22.6	51.1	63.3	75.8
	5	22.6	23.9	30.9	36.1	53.3	68.1

[a] The combined total of FFVs, PHEVs, BEVs, and FCVs.

CARB's most recent estimates of the incremental costs of PHEVs, BEVs, and FCVs were published in February 2008.[15] Cost estimates are presented for different types of BEVs and FCVs for model years 2012–2014 and 2015–2017. Estimates are also included in the report regarding the expected volumes of different types of BEVs and FCVs that allow composite costs to be computed. Using this information, and the midpoints of CARB's published cost ranges, the incremental costs for PHEVs, BEVs, and FCVs were computed and are shown in Table 6. Cost estimates for 2018 to 2020 were estimated by halving the CARB cost estimates for 2015 to 2017, which is how CARB staff arrived at costs for the 2015–2017 model year vehicles relative to the cost-estimates for the 2012–2014 model years. CARB staff used this approach in its February 2008 analysis to account for assumed cost savings associated with higher production volumes and decreases in component costs.

Table 6
Costs for PHEVs, BEVs, and ZEVs Based on 2008 CARB Staff Estimates

Type	2010 to 2014	2015 to 2017	2018 to 2020
PHEV	$25,000	$12,500	$6,250
BEV	$67,000	$36,000	$18,000
FCV	$270,000	$136,000	$68,000

Estimates of the total incremental vehicle cost for the specialized vehicles assumed in the ISOR were computed for each calendar year using CARB's $200 incremental cost estimate for FFVs and the cost estimates shown in Table 6 for PHEVs, BEVs, and FCVs. Undiscounted total costs for each of the five gasoline scenarios evaluated by CARB are shown in Table 7. As shown, the total incremental costs from 2010 to 2020 that would be incurred range from about $14.5 billion in Scenario 1 to $47 billion in Scenario 4. These incremental vehicle costs are larger than the $11 billion fuel cost savings that CARB staff claims will occur over the same period and the ISOR is silent as to why the costs of the specialized vehicles assumed by CARB staff to be required to achieve the LCFS standard should not be attributed to the LCFS since the greenhouse gas reductions of those vehicles are generally being claimed for the LCFS.

It should be noted that while CARB staff assumes far fewer electric heavy-duty vehicles in its Diesel scenarios, the costs of these vehicles are also ignored in the economic analysis.

[15] "Staff Report: Initial Statement Of Reasons 2008 Proposed Amendments To The California Zero Emission Vehicle Program Regulations," California Air Resources Board, February 8, 2008.

Table 7 Incremental Costs of Specialized Vehicles Assumed to Enter the California Vehicle Fleet between 2010 and 2020 in the Five Gasoline Scenarios	
Scenario	Cost in Billions of Dollars
1	14.5
2	14.6
3	23.9
4	47.0
5	23.9

As noted above, the incremental costs associated with specialized vehicles have been ignored in the LCFS economic analysis. However, these are real costs that would be borne by some entity, most likely California consumers, and that would have an impact on California's economy.

In addition to ignoring the incremental costs associated with specialized vehicles, the ISOR analysis of the greenhouse gas reductions and the impact of the LCFS on emissions of traditional air pollutants ignores the fact that these vehicles are subject to the Pavley standards and CARB's Low Emission Vehicle standards. According to the CARB staff's analysis, the Pavley greenhouse gas standards for new vehicles will result in a reduction of approximately 27 million metric ton of CO_2 equivalent (MMT CO_2 eq) emissions in 2020. All of the specialized vehicles assumed by CARB staff to be operating in California in the LCFS gasoline scenarios are subject to the Pavley standards. To the extent that vehicle manufacturers produce these specialized vehicles instead of conventional vehicles, they will receive credit for the reductions in greenhouse gas emissions associated with their operation on E85 and electricity and those credits can be used by vehicle manufacturers to comply with the Pavley standards while minimizing or potentially avoiding the need to make fuel economy improvements to conventional vehicles. Reports describing how E85 FFVs can be used by manufacturers to assist in complying or to fully comply with the Pavley standards have been published by both Michael Jackson of Tiax[16] and K.G. Duleep of EEA.[17,18] Mr. Duleep also describes how BEVs and FCVs required under the ZEV mandate reduce the level of fuel economy improvement manufacturers will have to make to conventional vehicles.

Although CARB staff claims that it has accounted for a 1.8 MMT CO_2 eq reduction in emissions due to the ZEV mandate, it has not accounted for the impact that greater numbers of PHEVs, BEVs, and FCVS will have on manufacturer compliance with the

[16] Jackson, M.D., "Alternative Fuels as a Compliance Option to Meet ARB's Greenhouse Gas Emission Standards," May 2, 2006.
[17] Duleep, K.G., "The Use of Ethanol Fuel to Meet Vermont Greenhouse Gas Emission Standards," August 2006.
[18] Duleep, K.G., "Technologies to Reduce Greenhouse Gas Emissions from Light-Duty Vehicles," April 2006.

Pavley regulations nor has the staff shown that it is not double-counting the GHG emission reductions associated with these vehicles.

Another important consequence of the impact of specialized vehicles on the Pavley regulation is that CARB staff has assumed that the Pavley regulations will result in a decrease in baseline gasoline demand over the period from 2010 to 2020. If that decrease in demand is smaller than estimated owing to the fact that manufacturers produce specialized vehicles rather than improving conventional vehicle fuel economy to the degree assumed by CARB staff, the volumes of lower carbon intensity fuels required to meet the LCFS standard will increase. Among other things, this could potentially mean that more bio-refineries are needed; feed stock demand, and therefore prices, will be greater; and there will be greater emissions increases associated with feedstock and biofuels transportation.

Similarly, in assessing the environmental benefits of the LCFS in Appendix F of the ISOR, emission reductions from ZEVs that have already been credited to CARB's Low Emission Vehicle standards are double-counted. When a manufacturer sells ZEVs, the fleet average NMOG standard allows manufacturers to sell conventional vehicles certified to emission standards higher than would otherwise be allowed under the regulations. To the extent that there are any emission benefits associated with increases in ZEV sales volumes, they have to be evaluated relative to emissions from the PZEVs they would likely displace, not the higher-emitting ULEVs that have been assumed in the ISOR environmental analyses, as indicated in Tables F8-2 and F8-3 of Appendix F.

As an illustration of the potential impacts associated with additional ZEV sales on criteria pollutant emissions, most BEVs will earn 3.0 ZEV credits during the 2015 to 2020 period while PZEVs and AT PZEVs will earn 0.2 and about 0.5 credits, respectively. As a result, the sale of each additional BEV above the minimum required for compliance with the ZEV mandate will relieve a manufacturer of the obligation to sell 15 (3/0.2) PZEVs or 6 (3/0.5) AT PZEVs. Depending on how constrained the manufacturer is by the fleet average NMOG standard of the LEV II regulations and the Pavley regulations, one likely scenario is that the ZEV purchased will replace a PZEV, which will result in an emissions reduction. As a result of the ZEV purchase, however, the manufacturer will then sell 14 SULEVs instead of 14 PZEVs, with the result being an emissions increase because the SULEVs are not required to meet 150,000-mile emissions control system warranty requirements and do not have to be certified to zero evaporative emissions standards. As a result, the emission reductions attributed by CARB staff to ZEVs in Table VII-13 of the ISOR are more likely emissions increases and the overall impact of the LCFS is likely to be an increase in criteria pollutants.

Another issue is CARB's assessment of the benefits of the federal Renewable Fuels Standard (RFS2). In the ISOR, CARB staff acknowledges that even in the absence of the LCFS, the RFS2 would yield about one-third of the total GHG reductions. What CARB staff fails to acknowledge is that all of these benefits will likely result from the use of renewable fuels in existing vehicles, rather than specialized vehicles, in which case the only costs that are material in the economic analysis are the costs associated with fuel production and distribution. CARB staff also fails to acknowledge that in order to achieve a significant fraction of the rest of the reductions claimed for the LCFS, it has had to assume that there would be large volumes of expensive specialized vehicles and a proper accounting would show the that the incremental cost-effectiveness of the LCFS relative to the RFS2 is poor.

Biomass Transportation Emissions

In order to estimate transportation emissions associated with biomass and biofuel transportation and distribution, the ISOR uses estimates adapted from a report prepared for the Western Governor's Association by U.C. Davis, Antares, and others.[19] This report identified candidate locations for biorefineries based in part on proximity to existing population centers. This was intended to help minimize transportation costs and "use population as a surrogate for availability of water and other essential services, including trucking, skilled labor, and materials." Assessment of air pollution emissions and the cost of air pollution controls was not a part of the study.

For 50 million gallon per year cellulosic ethanol plants, feedstock delivery per plant was estimated in the ISOR to require 110 truck trips per day per plant, with 50 miles for each round trip. The staff calculated emissions for all years from 2010 to 2020 using the assumption of 2020 emission factors. Assumed average travel distances and required number of truck trips for other feedstock deliveries varied by feedstock and plant type.

For the 19 new biorefineries considered in the ISOR, the total incremental truck VMT from delivery of biofuel feedstock by 25-ton trucks in 2020 was 41.5 million miles traveled (sum from Table F4-3, vol 2, pp F-31 to FF-33). Ethanol delivery for a 50 million gallon per year plant was assumed in the ISOR to require 20 additional truck trips per day per plant, and the statewide total of transportation and distribution emissions for 2020 biofacilities was estimated to include 5.2 tons per day of NOx and 0.102 tons per day of $PM_{2.5}$. According to the ISOR:

> *The major criteria pollutant emissions are associated with the additional biorefinery truck trips. On a statewide basis, these emissions may be offset by reductions in motor vehicle emissions. However, there still may be localized diesel PM impacts and localized facility emissions impacts.* (Vol 1, pg VII-2).

Later in the ISOR (Vol 1, pg VII-23), it is projected that, in the year 2020, 24 premature deaths, along with thousands of other non-fatal health impacts, are expected to occur statewide as a result of Diesel emissions from the increased truck traffic. There is no analysis contained in the ISOR in support of the statement that Diesel truck emissions "may be offset by reductions in motor vehicle emissions" on a statewide basis. In fact, available research suggests the opposite—increased ethanol concentrations in gasoline have been shown to increase NOx emissions from vehicles in the existing fleet and to increase permeation emissions of hydrocarbons from both on-road and off-road vehicles

[19] "Strategic Development of Bioenergy in the Western States, Development of Supply Scenarios Linked to Policy Recommendations," Report for the Western Governors Association prepared under USDA/DOE Bioenergy Contract Number: DE-PS36-06GO96002F, June 2008.

and equipment using plastic fuel tanks and elastomeric fuel lines. These impacts have been completely ignored in the ISOR.

There Would Be No Measurable Effect on Climate

The introduction of the ISOR makes it clear that the LCFS is intended to address "climate change"; however, the ISOR contains no estimate of the effect the LCFS would have on climate. Our independent analysis of the effect of the ISOR estimates of CO_2 emissions reductions attributable to the proposed regulation were modeled using version 4.1 of a coupled, gas-cycle/climate model known as MAGICC (Model to Assess Greenhouse-gas Induced Climate Change). MAGICC has been the primary model used by the Intergovernmental Panel on Climate Change (IPCC) to produce projections of future global-mean temperature and sea level rise. A manual explaining the model in more detail is publicly available.[20] The parameters for the modeling were as follows:

- "Mid"-level response for the carbon cycle model;
- Carbon cycle climate feedbacks set to "on";
- "Mid"-level response for aerosol forcing;
- 2.6°C sensitivity for doubled CO_2;
- "Variable" thermohaline circulation; and
- Vertical oceanic diffusion coefficient set to "2.3 cm^2/s."

The 2.6°C sensitivity to doubled CO_2 is consistent with the assumptions used in the most recent IPCC report, which is based on the assumption that the surface temperature record accurately reflects the effect of greenhouse gas concentrations on ambient temperatures. (Recent studies indicate that this assumption substantially overstates the effect of greenhouse gases on temperature.) Explanations of the other parameters are available in the above-referenced technical manual.

The baseline case assumed a future in which fossil fuels will continue to be consumed in a "business as usual" manner, but with new sources of energy mixing in to supply a balance of non-carbon-emitting sources. Two different scenarios were run to evaluate the potential effect of the proposed LCFS. One scenario assumed the staff's estimated reduction in CO_2 emissions from 2020 through 2050. The second scenario assumed the reductions estimated in the ISOR would be increased by a factor of 10 due to other jurisdictions adopting identical requirements.

Table 8 shows modeled changes in ambient temperature from a 1990 baseline temperature for each case. As shown in the table, the baseline case produces an estimated increase of 0.9980°C in calendar year 2050 over the 1990 baseline. The addition of the LCFS standard is estimated to reduce this temperature increase by one ten-thousandth (0.0001) of a degree. Assuming ten times greater emissions reductions, the temperature increase is reduced by 1.5 thousandths (0.0015) of a degree.

[20] T.M.L. Wigley, "MAGICC/SCENGEN 4.1: Technical Manual," National Center for Atmospheric Research, Colorado, October 2003.

Table 8 **MAGICC Version 4.1 Model Results (°C) for Calendar Year 2050**		
Scenario	Temperature Change from 1990 Baseline	Change Due to LCFS
Baseline (IPCC Case A1B)	+0.9980	n.a.
Low Carbon Fuel Standard in California	+0.9979	-0.0001
10 Times LCFS Reductions	+0.9965	-0.0015

To put the modeling results in perspective, current measuring systems are estimated to achieve a precision of about 0.04°C/decade.[21] Since the modeled impact of the LCFS is much smaller than our observational systems are able to measure, the impact would therefore be undetectable.

It should be noted that the modeling results described above are based on the assumption that the mandated sale of low carbon fuels will have no impact on the use of higher carbon fuels in areas not subject to the regulation. This is an unrealistic assumption because, to the extent that a LCFS decreases the demand for higher carbon fuels, the cost of such fuels will tend to decrease in areas not subject to a LCFS regulation. Lower cost will lead to increased consumption, which has been completely ignored in this analysis. Similarly, the analysis ignores the effect on fuel demand of the lower prices for low carbon fuels projected in the ISOR. If low carbon fuels were actually lower in price than conventional fuels, demand would be higher than baseline demand and there would be less of a reduction in GHG emissions.

[21] J.R. Christy, "Rebuttal Expert Report for the Plaintiffs," United States District Court for the District of Vermont, Case No. 05-cv-302, April 18, 2007.

Appendix 3 – ICF International – Outlook for PADD 5 Supply, Demand, and Infrastructure based on 2009 EIA Annual Energy Outlook

Outlook for PADD 5 Supply, Demand and Infrastructure Based on 2009 EIA Annual Energy Outlook

Study Performed for WSPA

April 6, 2009

Study Objective

- This report develops current and forecast petroleum supply and demand balances for the PADD 5 region, including:
  - 2007 actual supply and demand balances
  - Estimates of supply and demand for 2012 and 2020 timeframes from the preliminary EIA Annual Energy Outlook (AEO) 2009 publication
  - Estimates of required supplemental product from outside PADD 5 to balance supply and demand, including all assumptions on biofuels
  - Key infrastructure issues that will need to be resolved to enable balancing of supply and demand
  - Potential regulatory impacts on supply and demand in the 2012 and 2020 periods

Executive Summary

- PADD 5 product markets have undergone significant volatility in recent years. This has resulted in fuel products which are typically at higher prices than other domestic markets. There are a number of causes, including:
  - Increased demand levels in PADD 5 (prior to 2008) at relatively constant refinery capacity have triggered upward pressure on prices, which have attracted increasing levels of imports, primarily marine, through California ports.
  - The region is dislocated from prompt domestic and foreign supply alternatives to meet higher demands or for replenishment when disruptions occur
  - Unique product quality requirements in California, and different specifications in other states stress the distribution system and makes it difficult to secure replacement supply for California grades during disruptions
  - Port congestion, minimal additions to terminal storage and pipeline infrastructure have become increasing constraints at higher demands and as ethanol has been integrated in the supply chain
  - Regulatory uncertainty, permitting delays and NIMBY issues have contributed strongly to minimal investment in infrastructure and refinery capacity growth.

Executive Summary

- The forward outlook for PADD 5 supply and demand, based on AEO assumptions, indicates a strong likelihood for continued volatility and high levels of crude and product imported into the region.
  - Crude imports will increase by over 300 TBD by 2012 and 2020. Marine crude oil deliveries into PADD 5 ports are estimated to increase by 2020 to almost 2 million barrels per day (about 279 TBD above 2007 levels)
  - Minimal refinery capacity growth is anticipated over the period. This forecast assumes PADD 5 refinery utilization at 90% (2005-2008 average)
  - AEO demand growth assumptions indicate very slow to minimal growth for clean products in the 2007-2020 period (demands decline due to the recession then begin increasing again). Growth rates after 2020 (not in the study period) rise at about 2% annually for jet and distillates, under 1% for gasoline
  - Flat demands for gasoline and the impact of the RFS increases ethanol dramatically by 2012 and 2020. The increased ethanol supply significantly reduces the need for supplemental gasoline and blendstocks from imports and other PADDs. Required petroleum based gasoline supply declines by about 143 TBD to 2020.

Executive Summary (cont.)

- The overall increase estimated for hydrocarbon and biofuel imports/transfers into PADD 5 by 2020 is significant:
  - Crude Oil 329 TBD
  - Jet and Diesel - TBD (includes 20 TBD Bio-based supply)
  - Gasoline/Blendstocks (143) TBD
  - Ethanol 121 TBD (includes 23 TBD new PADD 5 production)
- If the AEO assumptions are in fact reasonably accurate, the logistics of crude supply and ethanol will become more critical. The supply of gasoline, jet and diesel will be less dependent on imports, and in fact may result in weaker refiner margins, particularly for gasoline.
- These results, however are highly contingent on a number of assumptions which do not reflect the exposure that the PADD 5 region, and California in particular (due to its high demands) has. These include the following (next)

Executive Summary (cont.)

- **Assumption Sensitivities:**
  - AEO demand growth through 2020 reflects essentially no growth for jet and gasoline from 2007 and under 1% annual growth for distillate. The implications of a higher demand growth rate of 1% more than the AEO assumptions for each product will increase import requirements in PADD 5 by a total of 350 TBD, including 20 TBD ethanol by 2020.
  - The study assumes refinery capacity is slightly increased from 2007, and that utilizations will average 90%. The reduced dependence on outside imports of gasoline & blendstock as ethanol demand grows is very likely to pressure refiner margins and result in either reduced utilization or some refinery closures. This will decrease crude imports, but raise import/transfer requirements for products. Since product specifications are unique in California and some other PADD 5 states, this will make importing more costly and require better port infrastructure.
  - The biofuel requirements in this forecast are primarily driven by the Renewable Fuel Standard (RFS). The AEO assumes that the RFS is met through 2012, but then biofuel usage begins to lag the RFS. Biofuel usage in 2020 is at about 73% of the RFS (22 bgy vs 30 bgy RFS), and cellulosic ethanol supply is at only 2.1 bgy vs 10.5 in the RFS. While the AEO reflects the challenges of cellulosic commercialization, an assumption of 2.1 bgy (140 TBD) will still require construction and streaming of 50-100 cellulosic ethanol refineries by 2020. The high cost of second generation ethanol pathways may make even the 2.1 bgy assumption challenging without significant technology breakthroughs.

Executive Summary: Regulatory Implications

- This outlook reflects government initiatives to reduce fuels consumption and to increase the use of biofuels per the 2007 EISA. There are a number of additional Federal, State and regional initiatives that have been enacted or are likely to be enacted which will continue to develop reduced dependence on fossil (carbon) based fuels. PADD 5 states, in particular California are on the leading edge of these initiatives.
- The implementation of this legislative slate has not fully been determined, however it is clear that legislation such as California's AB32/LCFS legislation is moving to adoption in other states and possibly at the Federal level. California's AB118 provides funding mechanisms to accelerate development and deployment of alternative fuel technologies.
- The impact of these government initiatives is not in the AEO 2009 outlook assumptions.

Executive Summary: Refining Implications

- As these initiatives move forward and as they result in tangible growth in alternative fuel supply, the implications for the refining industry are significant.
  - Fundamental demand for petroleum based fuel will decline
  - Operational costs may rise significantly based on the potential cost of carbon
  - Foreign refiners may not have similar carbon costs which threatens U.S. industry competitiveness
  - Investment in U.S. refining capacity or upgrading will be very high risk due to likely poor margins and potential carbon costs
  - There will be a high potential for refinery closures
- Example: the major Gulf Coast expansions at Motiva, Marathon and Valero in the 2010-2011 timeframe are forecast in the 2009 AEO to result in NO increase in refinery crude runs. Utilization (U.S.) is forecast to decrease from 89% in 2007 to 78% in 2011. U.S. crude runs will decline by 1 MMBD from 2007 levels as new capacity growth of about 0.8 MMBD is streamed. This outlook – *which does not reflect the impact of developing carbon legislation* – is very likely to drive U.S. refinery closures since utilizations under 85% have been unsustainable for many refiners in the past.

Executive Summary: Market Risk in PADD 5

- The emerging legislative initiatives in PADD 5 and on a Federal level indicate refinery supply assumptions in this study may be very optimistic. This means that refining supply of gasoline, jet and diesel fuel may be lower than forecast in this study.
- This will make it essential that PADD 5 states develop alternative fuel options and required infrastructure on a priority basis to meet forecast demands in the region. Should demand growth return to more historical levels sooner than predicted in the AEO, the gap between supply and demand may widen to levels well above predicted.
- PADD 5 states, in particular California, must be prepared to handle higher levels of ethanol transfers and imports, produce more in-region biofuel and other alternative supplies than forecast in this study, and deploy infrastructure to enable distribution of those products.
- Achievement of LCFS goals such as electric & hybrid vehicles will increase power generation needs. This may require development of new nuclear or biomass generation to meet demand without increasing carbon.

Executive Summary: Key Messages

1. Movement toward decreased reliance on fossil fuels as evidenced in the 2009 AEO outlook and through additional emerging regulatory initiatives is likely to result in a shrinkage of the U.S. and PADD 5 refining industry (in fact this is an objective of the policies that have led to these initiatives).
2. The deployment of increased biofuels and alternative fuels (including electric/hybrid vehicles) in PADD 5 is highly contingent on a) development of new and more cost effective technologies to produce the alternative fuels; b) storage & distribution infrastructure; c) fueling infrastructure; d) vehicle technology & production and e) consumer investment in new vehicles & fuels. Failure to achieve *ANY* of these objectives will significantly jeopardize the required growth in petroleum alternatives. This may greatly increase the likelihood of fuel supply disruptions and price volatility as demands grow and refining capacity may not be available to meet the shortfall.
3. The multiple approaches to regulation (Federal, State, Regional, etc) has the potential to create significant distribution system conflicts in PADD 5 if regulations are not well coordinated and consistent. With the AEO forecast outlook indicating sustained requirements for product exogenous to PADD 5, policy inconsistencies in the region can exacerbate the supply situation during the transition to alternative fuel pathways.

METHODOLOGY & ASSUMPTIONS

Basic Assumptions

- Primary data sources for this report include:
  - EIA actual historical data through November 2008
  - EIA 2009 AEO Forecast assumptions on demand growth, refinery capacity and biofuel penetration
  - Renewable Fuels Association and National Biodiesel Board publications for existing capacity and capacity under construction (modified with input from state energy officials if known)
- The AEO 2009 forecast divides PADD 5 states into two Census Divisions:
  - 1. Pacific Division: Alaska, California, Hawaii, Oregon, and Washington
  - 2. Mountain Division: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming
- ICF developed PADD 5 forecasts based on these two AEO Census Divisions
  - Assumes percentage Mountain demands for Az/Nv consistent with recent history
- Note: In this report, “Import” means foreign imports; “Transfers” means movements between PADDs; “Influx” means total Import and Transfers

Process: Supply & Demand Forecasting

- The study uses the base 2007 actual PADD 5 supply and demand balance as a starting point, with known actual volumes of foreign imports and transfers from other PADD districts to balance supply and demand
- 2008 supply and demand is estimated from EIA November YTD data
- Forward year demands, including biofuel penetration, are determined from the 2009 AEO demand forecast growth rates for study products (Gasoline, E-85, Jet, Distillate and Residual fuel
- Forward year supply is determined from AEO estimated refinery capacity at 90% utilization (2005-2008 PADD 5 average). Incremental product based on 2007 yields (% gross input to distillation) with adjustments for known upgrading projects (minimal)
- PADD 5 current and under construction ethanol capacity was assumed to have 90% utilization by 2010.

Process: Supply Balancing

- Displacement of gasoline by increased ethanol usage is assumed to reduce imports of gasoline and blendstocks first, then reduce transfers from other PADDs, and lastly gasoline production from within PADD 5. Incremental ethanol requirements will most likely be transferred from other PADDs by rail, but imports may also arrive by water if port infrastructure is in place for ethanol.
- Changes in Jet and Diesel fuel supply and demand are balanced by altering imports first, then transfers from other PADDs
- Incremental crude oil requirements to displace declining California production are assumed to come from more foreign imports
- Refinery utilization was held constant through the study period; refinery yield of gasoline, jet, diesel and residual fuel were assumed to be at 2007 actual levels. (Note: refiners have flexibility to modify yields between gasoline and distillate products to a limited degree, as occurred in 2008 with diesel prices well above gasoline. The AEO Pacific region pricing shows future prices of gasoline above distillate, more similar to 2007 levels. Should market conditions change and favor distillate production over gasoline, study results would simply shift to lower distillate imports and higher gasoline imports)
- Practically, economics at the time will influence whether imports, PADD transfers or refinery changes are the primary supply balancing flywheel.
- Ports in PADD 5, in particular California, are assumed to have the capacity (dock, storage, etc.) to meet the estimated changes. But port capacity in fact will require additional infrastructure investment to handle estimated increased import levels.

STUDY AREA BACKGROUND

The PADD 5 Market is Large, but Isolated from the Rest of the U.S. Infrastructure…

- PADD 5 accounted for 18% of U.S. Fuel Consumption* and 27% of U.S. Crude Supply in 2007.
- Refinery Capacity is 18% of the U.S. total, and ethanol capacity is under 3%.
- Major refining centers are located in Los Angeles, San Francisco and Puget Sound.
- No crude pipelines connect the PADD 5 market to the rest of the U.S., and two product pipelines provide about 8% of PADD 5 supply (primarily from Texas). Marine movements on U.S. flag vessels from the Gulf Coast require several weeks' time to actually land in PADD 5.
- Product quality requirements in California are unique and difficult to meet; other PADD 5 states are moving to different specifications.
- PADD 5 has needed more imports of gasoline, components, jet and diesel fuel in recent years to balance growing demands.
- Product specification differences from other markets, distance from timely replenishment, and port congestion can make it difficult to respond quickly to supply disruptions and these facts can lead to price volatility.

* Gasoline, Jet, Diesel & Residual fuel

2007 Actual PADD 5 Product Balance

(TBD)

	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Supply					
Refinery Production	1,314	404	539	164	2,421
Imports	94	112	30	35	271
Net PADD Transfers	143	6	29		178
Ethanol/Biodiesel	79		4		83
Total Supply	**1,630**	**522**	**602**	**199**	**2,953**
Non-PADD 5 Supply	*19%*	*23%*	*10%*	*17%*	*18%*
Demand					
Consumption	1,626	507	569	156	2,858
Exports	4	15	33	43	95
Total Demand	**1,630**	**522**	**602**	**199**	**2,953**

Motor gasoline volumes include blending components.

Refinery production of motor gasoline includes straight-run gasoline and hydrogen.

Source: EIA

A More Detailed Look at 2007 Actual PADD 5 Supply of Motor Gasoline

(TBD)

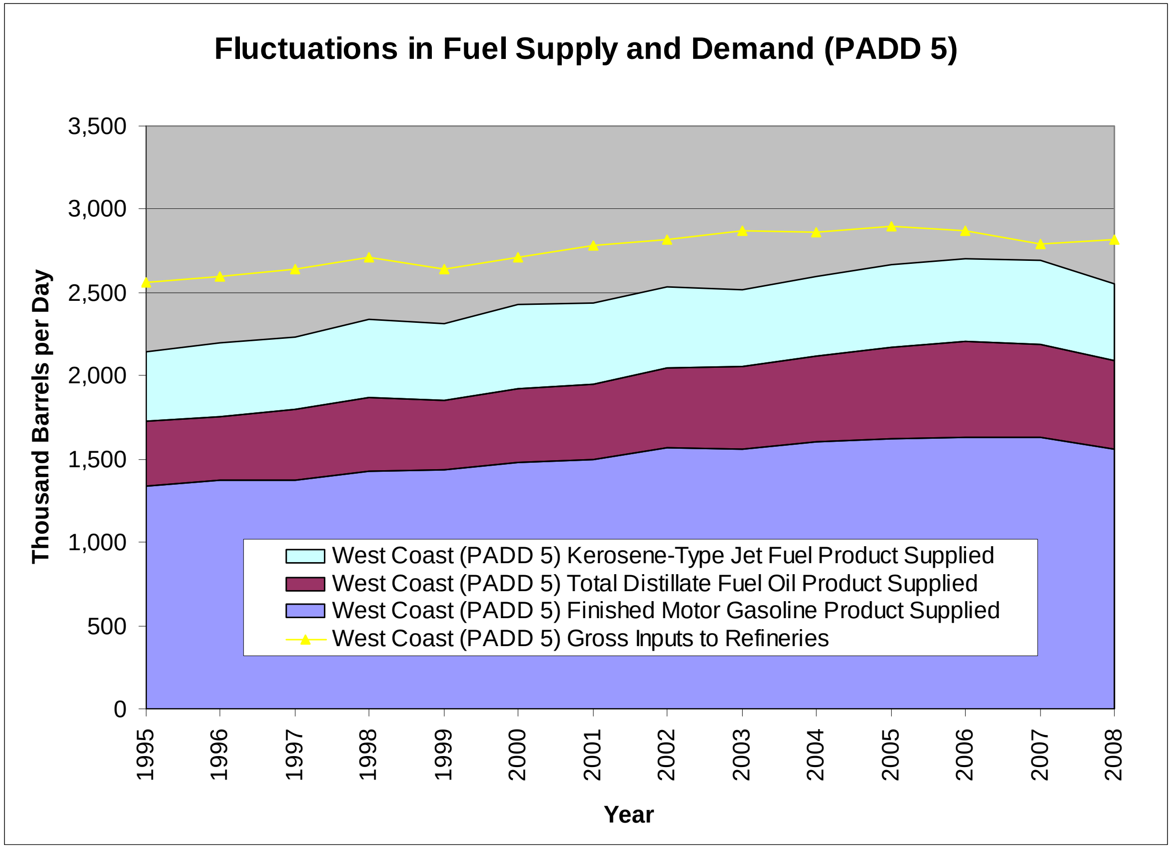
Production	**1,320**
Petroleum Refineries*	1,314
Biorefineries	6
Imports	**101**
Finished Motor Gasoline	34
Blending Components	64
Ethanol	3
Transfers into PADD 5	**212**
Finished Motor Gasoline	105
Blending Components	38
Ethanol	69
Inventory	**(4)**
Finished Motor Gasoline	1
Blending Components	(5)
Ethanol	0.1
Total Supply	**1,630**

- Imports from foreign locations were about 100 TBD in 2007, primarily blending components.
- Transfers (Movements) from other PADDs were significant; Ethanol was delivered by railcar primarily from PADD 2.

* Refinery production of motor gasoline includes straight-run gasoline and hydrogen.

Source: EIA

Refinery Input Levels have been Stable in PADD 5 since 2003 as Gasoline and Distillate Demands Rose through 2007…

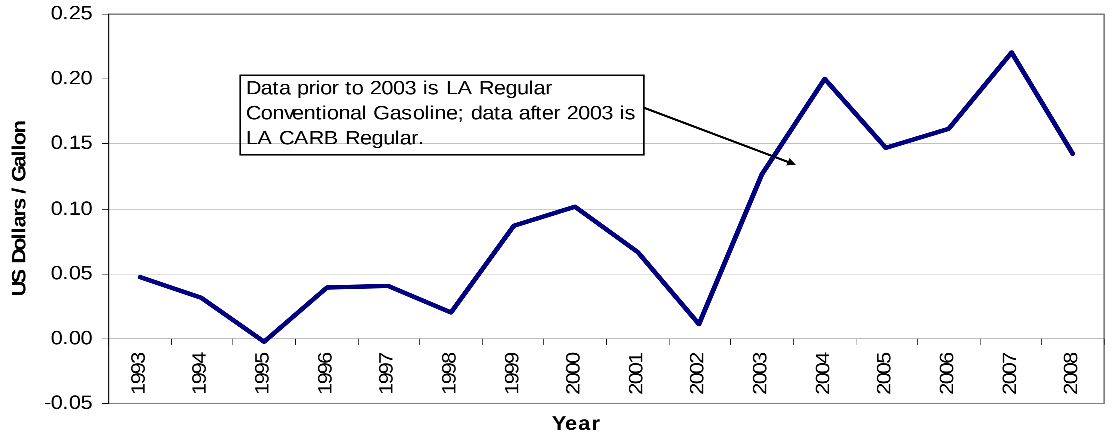


Source: EIA

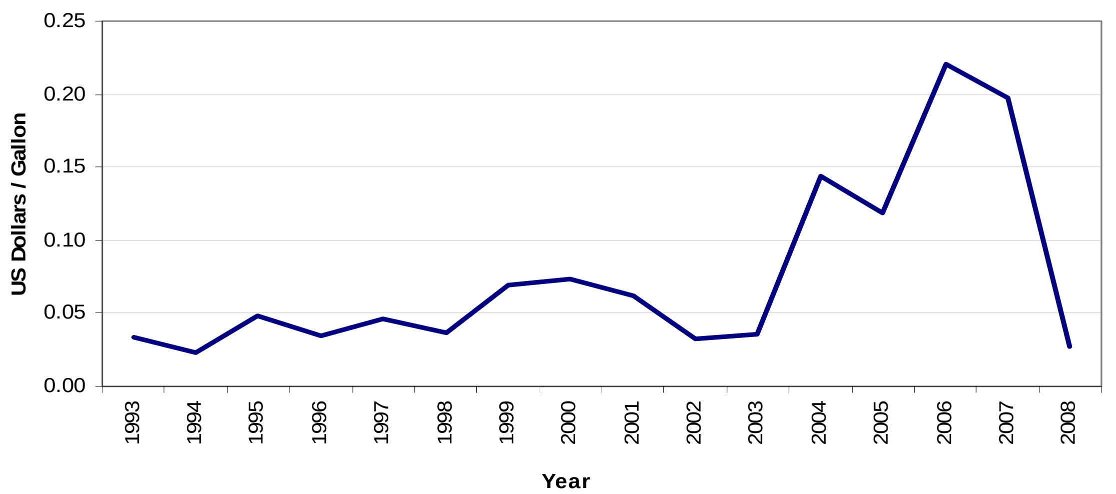
- The narrowing "gap" between demand for products and refinery input, and product quality transitions, have put more stress on the supply-demand infrastructure.
- Demand increases of over 500 TBD (23%) occurred from 1995 to 2007 with virtually no change in PADD 5 infrastructure (terminal storage, pipelines, marine) and minimal refinery capacity growth.

- Higher prices and the recession have reduced total demand in 2008 by about 140 TBD clean products (5%)

These Trends Contribute Significantly to Higher Gasoline and Diesel Price Spreads vs. NYMEX over the Period



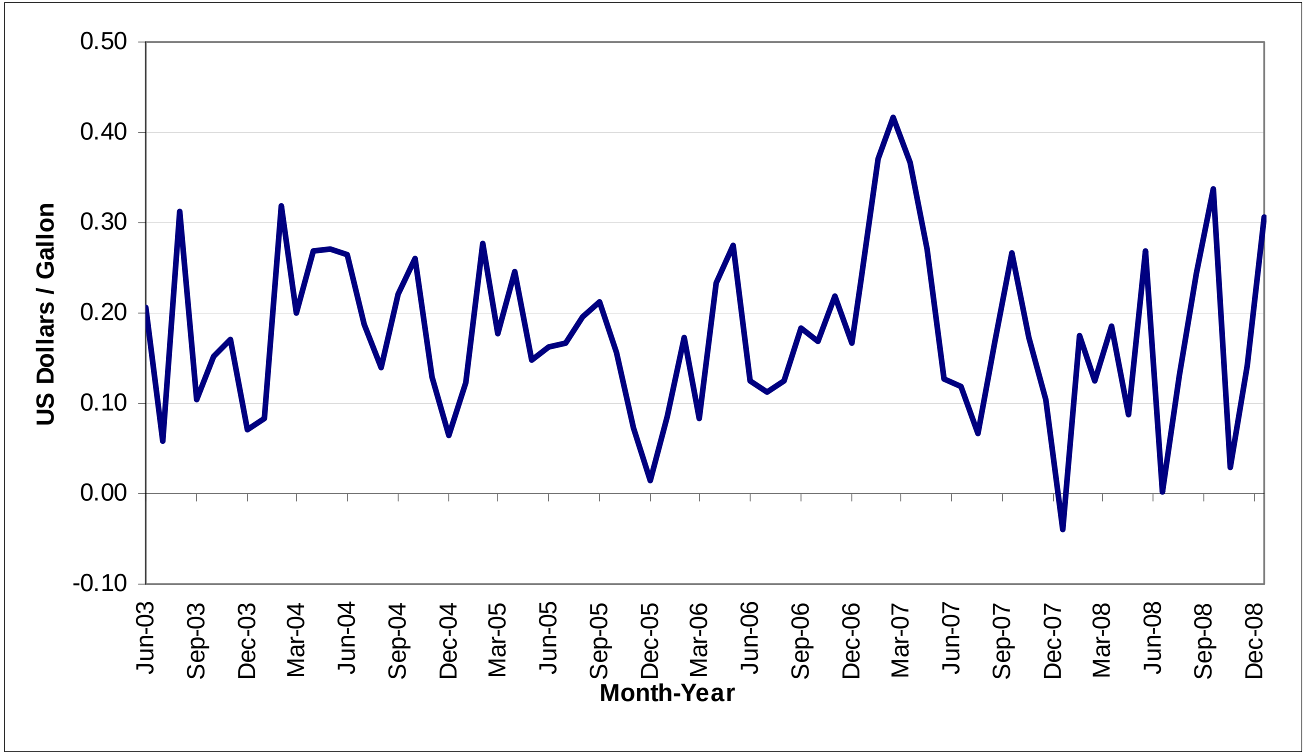
[1] Conversion from NY Harbor Regular Gasoline to NY Habor Reformulated RBOB Regular Gasoline Futures Price took place in 2005.



- Changes in demand volumes and product quality requirements appear to have impacted PADD 5 markets
- The changes since 2003 are dramatic and have been sustained
- Collapse in diesel in 2008 stems from increased production & lower demands (stimulated diesel exports)

Source: EIA

Monthly Data on CARBOB Gasoline Price Spread vs. NYMEX Shows Large Price Swings…



Source: EIA

- High degree of volatility in price spread versus NYMEX is indicative of a tight supply/ demand balance.

2007 Actual Volumes and Sources of Non-PADD 5 Origin

(TBD)

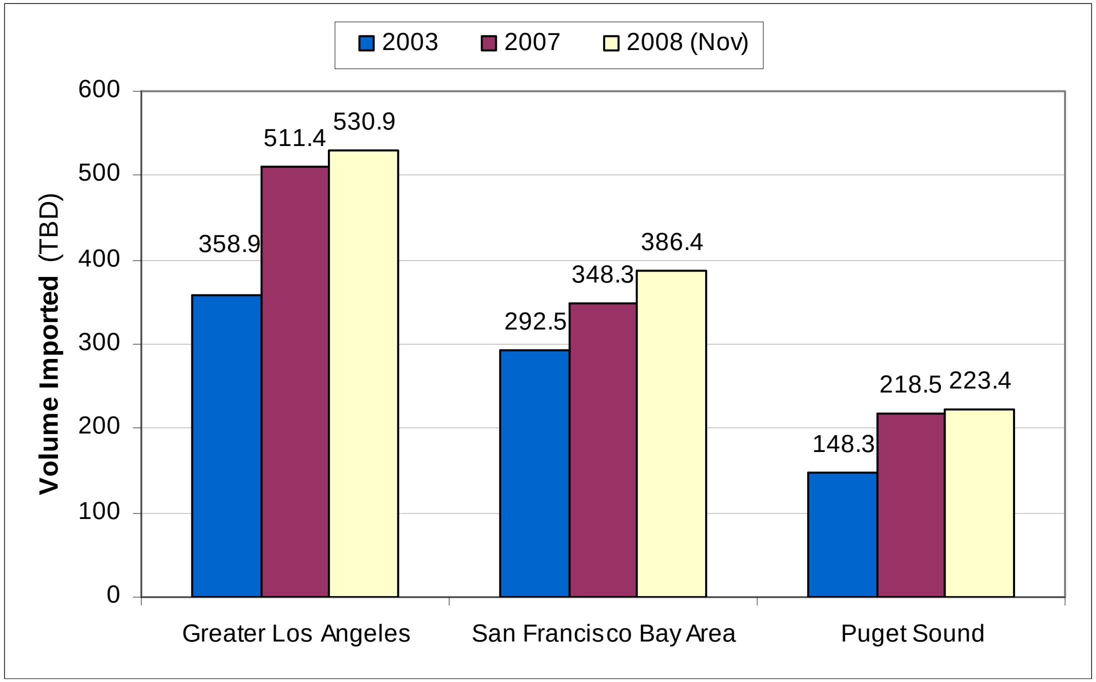
Mode of Shipment	Crude Oil	Motor Gasoline	Ethanol	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Marine	1,023	107	3	115	34	35	1,317
Pipeline	126	135		6	28		295
Rail			69				69
Total Non-PADD 5 Supply	**1,149**	**242**	**72**	**121**	**62**	**35**	**1,681**

Source: EIA

- PADD 5 dependence on crude, petroleum products and ethanol supply from outside the region in 2007 was extensive. This dependence has been the case, to varying degrees, for several years as regional crude supply has decreased and demands for products have increased.
- Crude oil imports (which exclude North Slope) are about 40% of refinery crude oil processed.
- Gasoline “imported” to the region includes finished gasoline, “BOB” product for ethanol blending, or direct gasoline blending components required in California to meet state product specifications.

Marine Deliveries of Foreign Crude and Unfinished Oil Imports by Port Region have Increased Since 2003…

Crude and Unfinished Oils



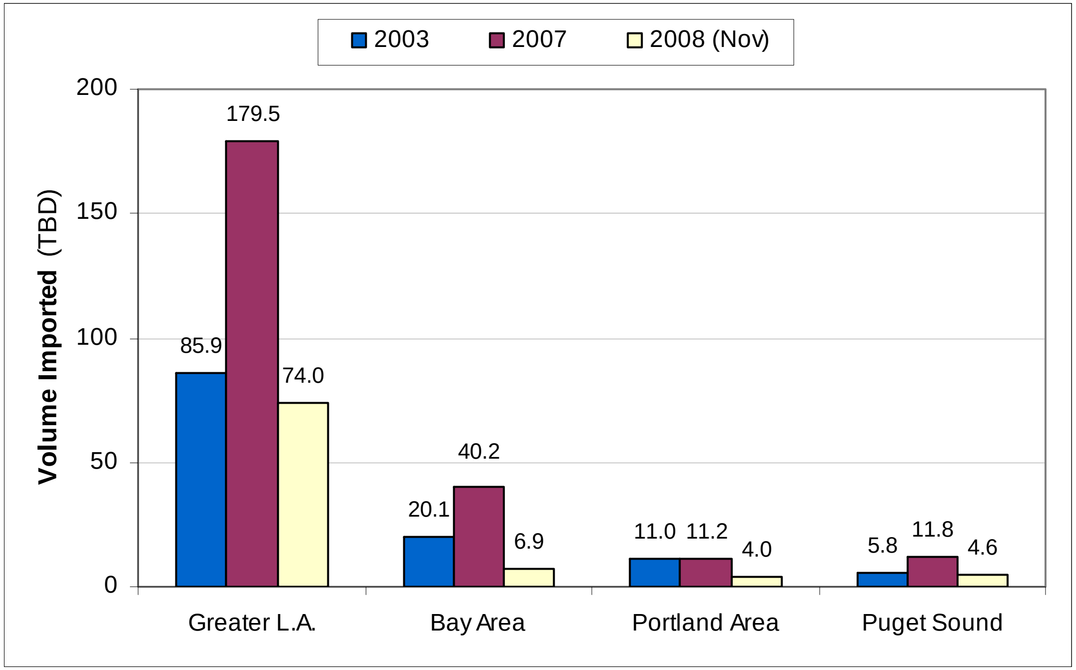
Source: EIA

- Import growth driven by 90% refinery utilization (avg) and declines in California crude supply
- Volumes through Nov 2008 have increased by over 340 TBD since 2003

- **Note: volumes do not include ANS marine deliveries to West Coast. In 2007 all ANS production was shipped to the U.S. West Coast except for volumes to meet Alaska finished product demand (estimated at about 120 TBD). ICF estimates about 600 TBD ANS supply in 2007 to California and Washington ports.**

Product Imports into California rose rapidly from 2003, but Lower Demands in 2008 Cut Imports

Total Petroleum Products

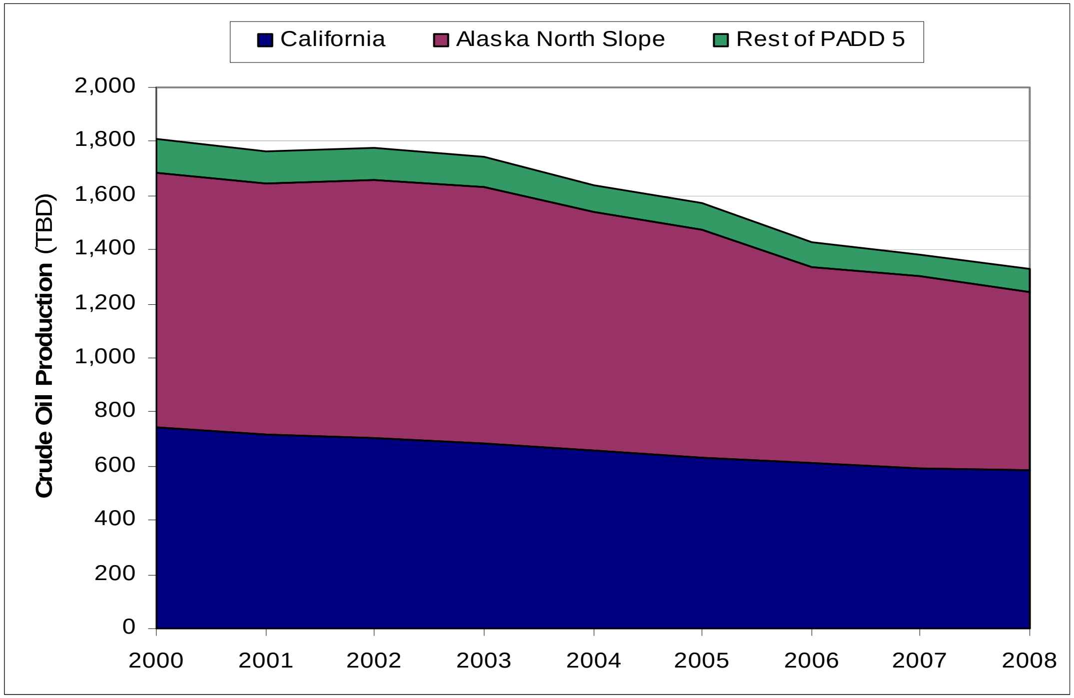


Source: EIA

➢ Bottom Line: Demands can change rapidly up and down based on the economy

- Reduced imports were influenced by lower demands for clean products
- Jet imports dropped by 95 TBD in PAD 5; Gasoline (including components) by 50 TBD
- Port traffic numbers shown exclude exports, which rose by 80 TBD clean products in 2008

PADD 5 Crude Oil Production Trend Has Been in a Sustained Decline…



- Production decline since 2000 has been over 420 TBD, or 23% since 2000.

Rest of PADD 5 includes production in South Alaska, Arizona, Nevada, and Federal Offshore.

Source: EIA

2008 data through September 2008

STUDY AREA FORECAST THROUGH 2020

Supply and Demand Balance Forecast Assumptions: Refining Supply

- The AEO forecast shows refinery capacity in PADD 5 is flat until 2020, when it increases about 25 TBD. Incremental clean product volumes in 2020 are estimated at 2007 actual yield.
- ICF forecasted refinery throughput and production based on 2007 actual data, AEO forecasted refinery capacity growth, and 90% utilization of operable capacity (2005-2008 PADD 5 actual average). Since 2007 utilization was 87.6%, forecast refinery production was adjusted to 90% based on 2007 yields.
- Note: the AEO forecasts refining utilization declining nationwide to levels in the 78% range after streaming of new Gulf Coast capacity in 2011. This study assumes that PADD 5 refinery utilization will remain at 90% levels over the study period.
- ICF has estimated that announced projects to increase heavy crude processing in PADD 5 would have minimal impact on incremental gasoline and diesel supply. ICF has assumed, based on public announcements, that a delayed coker project (20 TBD) will be streamed in 2015, adding 16 TBD
- The study assumes that the UNEV pipeline (Salt Lake to Las Vegas) is complete at 60 TBD capacity by 2011 for logistics flexibility into PADD 5

Supply and Demand Balance Forecast Assumptions: Biofuel Supply

- PADD 5 ethanol capacity is based on 2009 RFA* capacity in PADD 5 states. ICF used RFA Jan 2009 capacity for 2009 and assumed all projects under construction completed by 2010.
- ICF assumed ethanol capacity utilization of 90% for PADD 5 producers (November 2008 utilization was 85%). ICF assumed no additional ethanol production capacity in PADD 5 beyond announced under construction projects (More or less in-PADD production will alter forecast PADD 5 import requirements from other PADDs or U.S. imports. This methodology identifies the maximum potential exogenous PADD 5 supply.)
- Biodiesel capacity reported in NBB* reports is overstated based on input from PADD 5 state energy officials. AEO assumptions for PADD 5 (Pacific plus Mountain regions) biodiesel demands were used for supply assumptions. These show biodiesel capacity utilizations of 12% in 2007, 30% in 2015 and 44% in 2020 at NBB 2010 capacities.

* RFA is Renewable Fuel Association; NBB is National Biodiesel Board

Supply and Demand Balance Forecast Assumptions: Demands

- Demand growth is based on 2007 and 2008 (YTD November) actual demands for PAD 5 (EIA), with forecast annual growth rates based on the new 2009 AEO outlook for the Pacific and Mountain census regions.
- The AEO 2009 U.S. forecast includes the EISA 2007 RFS, but limits total renewables to 23.3 billion gallons in 2020 vs. the 30 billion gallon RFS target. EIA forecasts the quantities of cellulosic biofuels will be insufficient to meet the full renewable target due to technology development and market penetration (2020 cellulosic volumes in the 2009 AEO are 140 TBD vs the 700 TBD in the EISA).
- Pacific and Mountain Census Divisions achieve 10% ethanol in gasoline by 2012, which grows to 12.4% by 2020 due to increased E-85 demand (the AEO does not exceed the 10% “blend wall” in non-E-85 gasoline).
- The demand assumptions in the 2009 AEO for forecast growth rates and ethanol penetration are significantly lower than the 2008 AEO assumptions reflecting the impact of higher energy prices on demands and the reduced expectations for cellulosic development (See Appendix 1)
- Exports are assumed to average 2007 levels (typical of history) for key products. Higher exports in 2008 were a reflection of the rapid drop in demand and strong refinery utilization (90%).

Demand Forecasts for PADD 5 Based on 2009 AEO shown on Next Two Slides…

PADD 5 AEO-based Product Consumption Forecast Shows Large Increases in Ethanol, Jet and Diesel Demand

(TBD)	2007	2012	2020	Change 2007-2020
Finished Motor Gasoline	1,626	1,621	1,609	(17)
E85	*0.2*	*0.2*	*64*	*64*
Finished Motor Gasoline (Quadrillion Btu)	*3.0388*	*2.9948*	*2.9460*	*(0.0928)*
Motor Gasoline Blending Components	1,547	1,461	1,404	(143)
Ethanol	79	160	200	120
Liquids from Biomass	0	0.2	5	5
Jet Fuel	507	450	512	5
Distillate Fuel Oil	568	570	622	54
Petroleum-derived	564	560	602	38
Biodiesel	4	9	14	9
Liquids from Biomass	0	0.3	6	6
Residual Fuel Oil	157	173	178	21
TOTAL	**2,858**	**2,814**	**2,921**	**63**
Petroleum-derived	2,775	2,644	2,696	(78)
Renewables	83	170	225	141

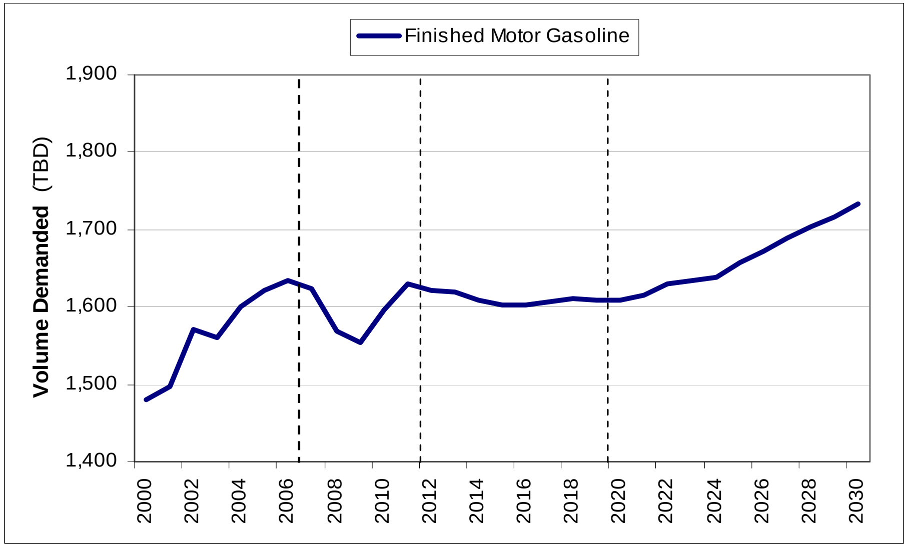
Italicized items are not part of the breakdown of finished motor gasoline by component volumes.

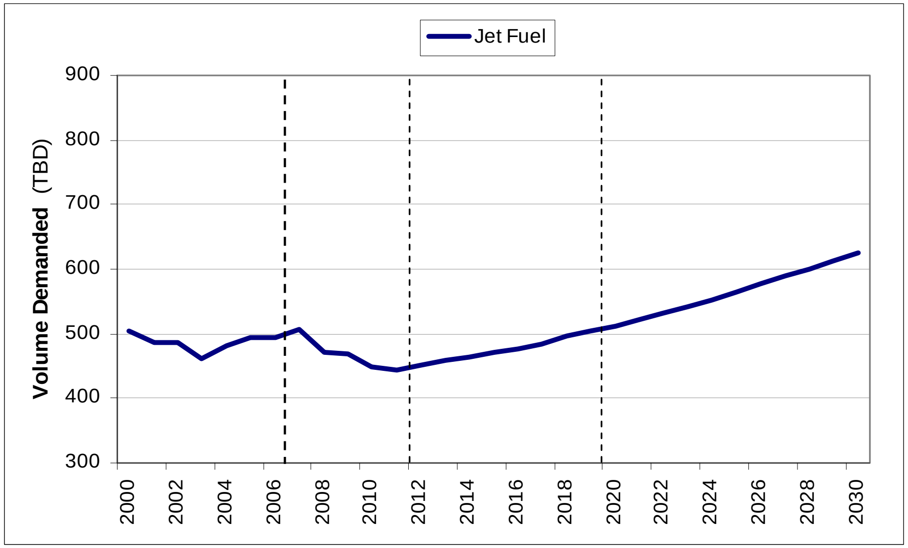
Forecasted volumes for ethanol and motor gasoline blending components are based on national-level blending proportions derived from AEO-forecasted energy content of ethanol in E85 and motor gasoline (Reference Case Table 17).

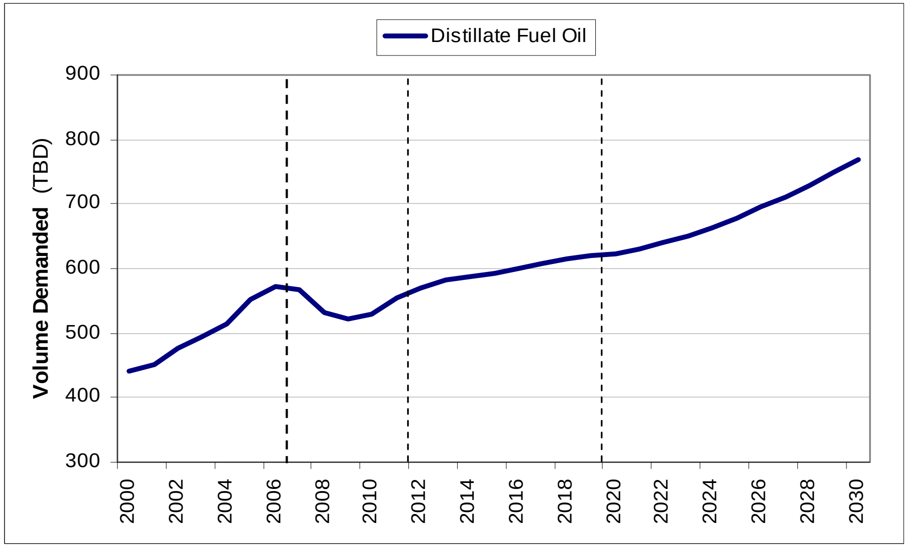
Forecasted volumes for biodiesel and liquids from biomass are based on national-level blending proportions derived from AEO-forecasted supply volumes (Reference Case Table 11). As advised by EIA staff, the following are assumed for liquids from biomass: 40% naphtha streams to be blended into gasoline, 60% distillate streams.

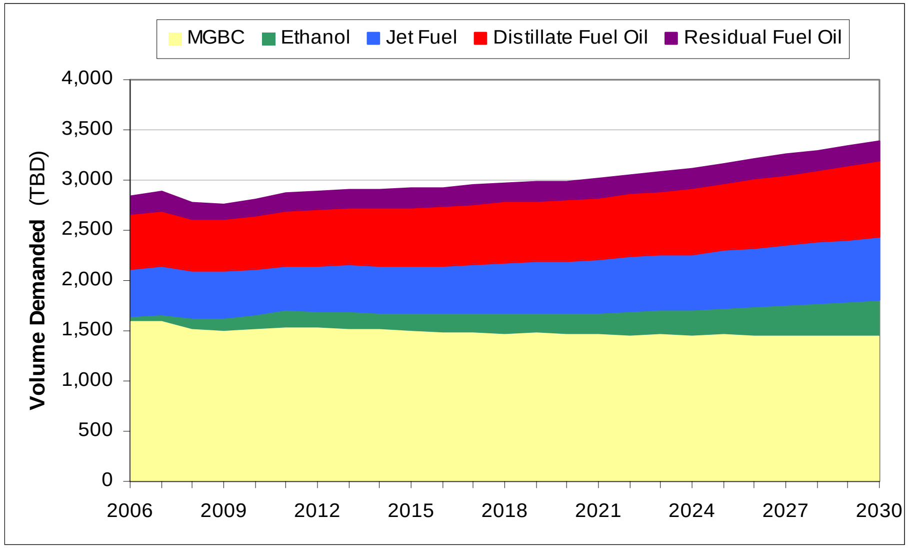
Source: EIA AEO 2009

PADD 5 Product Consumption Forecast Charts





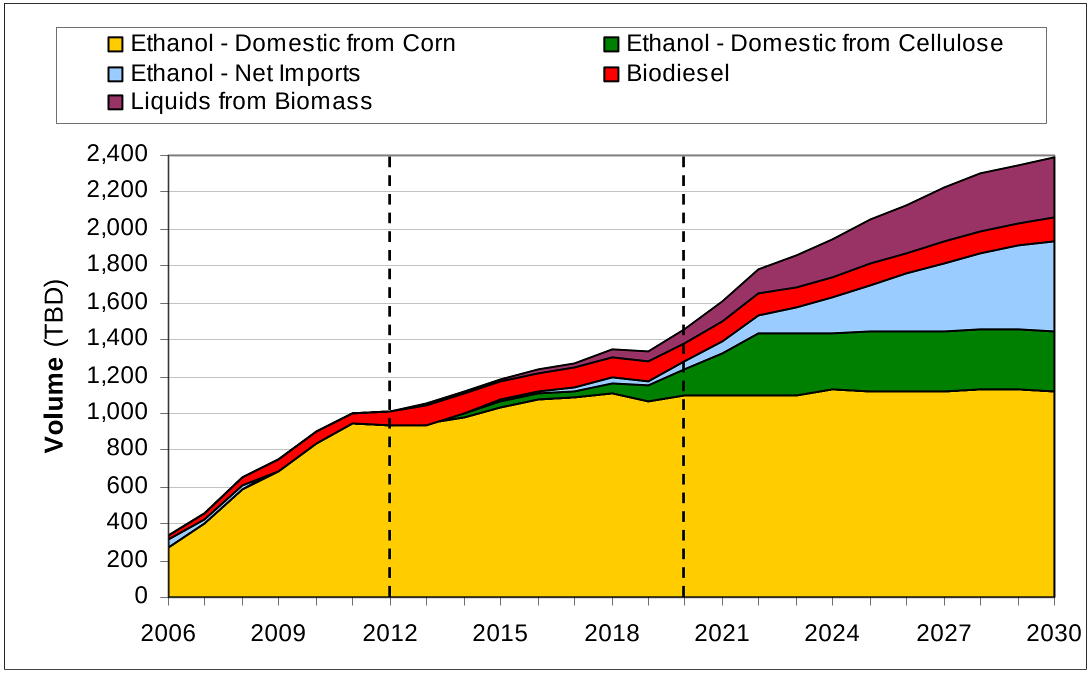




Source: EIA AEO 2009

2008 data through November 2008

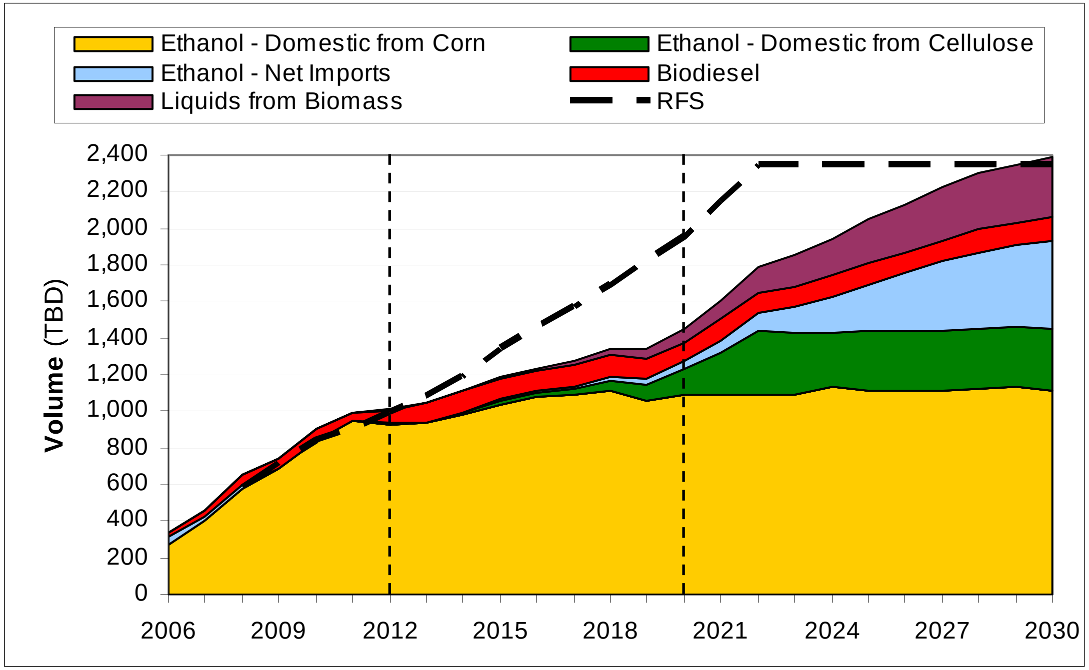
AEO-forecasted U.S. Supply of Renewable Transportation Fuel Grows to 2030…..



Source: EIA AEO 2009

- Ethanol from corn and other grains increases to about 1 MMBPD (15 billion gpy) by about 2015 and stays flat thereafter over the AEO period.
- Cellulosic ethanol begins in 2012 and steps up significantly in 2018-2022, and then is stable.
- Biodiesel grows through 2012 and then is assumed stable over the period.
- Liquids from biomass (assumed 40% naphtha and 60% distillate by EIA) begins about 2012 and increases over the full AEO period.

But Growth Lags the RFS through 2020



Source: EIA AEO 2009

- Cellulosic ethanol production is 30% of RFS cellulosic goal in 2012, and 20% in 2020 (See Appendix 2)
- Note that essentially all growth after 2022 is through ethanol imports and biomass liquids

The lag in second generation ethanol growth versus the RFS, and the flat production outlook for biodiesel reflect the fact that current technology and feedstock costs may not be adequate to accelerate supply of these commodities in the AEO timeframe (without new breakthroughs)

The following slides show overall supply & demand balances for 2007, 2012 and 2020 for products in PADD 5. These are followed by specific discussion of trends for gasoline, jet and distillates based on AEO assumptions.

2007 Actual PADD 5 Product Balance

(TBD)

	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Supply					
Refinery Production	1,314	404	539	164	2,421
Imports	94	112	30	35	271
Net PADD Transfers	143	6	29		178
Ethanol/Biodiesel	79		4		83
Total Supply	**1,630**	**522**	**602**	**199**	**2,953**
Non-PADD 5 Supply	*19%*	*23%*	*10%*	*17%*	*18%*
Demand					
Consumption	1,626	507	569	156	2,858
Exports	4	15	33	43	95
Total Demand	**1,630**	**522**	**602**	**199**	**2,953**

Motor gasoline volumes include blending components.

Refinery production of motor gasoline includes straight-run gasoline and hydrogen.

Source: EIA

2012 Forecasted PADD 5 Product Balance

(TBD)

	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Supply					
Refinery Production	1,353	416	555	169	2,492
Imports		33		47	80
Net PADD Transfers	112	17	38		167
Ethanol / Biodiesel	160		9		169
Liquids from Biomass	0.2		0.3		0.5
Total Supply	**1,625**	**466**	**602**	**216**	**2,909**
Non-PADD 5 Supply	*15%*	*11%*	*6%*	*22%*	*13%*
Demand					
Consumption	1,621	450	570	173	2,814
Exports	4	15	33	43	95
Total Demand	**1,625**	**466**	**602**	**216**	**2,909**

Motor gasoline volumes include motor gasoline blending components.

Source: EIA

2020 Forecasted PADD 5 Product Balance

(TBD)

	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Supply					
Refinery Production	1,373	420	568	150	2,510
Imports		91	14	71	176
Net PADD Transfers	35	17	53		105
Ethanol / Biodiesel	200		14		213
Liquids from Biomass	5		6		11
Total Supply	**1,612**	**528**	**655**	**221**	**3,016**
Non-PADD 5 Supply	*13%*	*20%*	*10%*	*32%*	*15%*
Demand					
Consumption	1,609	512	622	178	2,921
Exports	4	15	33	43	95
Total Demand	**1,612**	**528**	**655**	**221**	**3,016**

Motor gasoline volumes include motor gasoline blending components.

Source: EIA

Motor Gasoline Forecast Supply & Demand

(TBD)

	2007	2012	2020	Change 2007-2020
Supply				
Refinery Production	1,314	1,353	1,373	59
Imports	94			(94)
Net PADD Transfers	143	112	35	(108)
Ethanol / Biodiesel	79	160	200	121
Liquids from Biomass		0.2	5	5
Total Supply	**1,630**	**1,625**	**1,612**	**(18)**
Non-PADD 5 Supply	*19%*	*15%*	*13%*	
Demand				
Consumption	1,626	1,621	1,609	(17)
Exports	4	4	4	0
Total Demand	**1,630**	**1,625**	**1,612**	**(18)**

Motor gasoline volumes include motor gasoline blending components. Imports modified slightly in 2007 to eliminate inventory build or draw

Source: EIA

Summary Observations on Changes in the Gasoline Supply & Demand Balance

- Total ethanol requirements in PADD 5 grow from 79 TBD in 2007 to 160 TBD in 2012 and 200 TBD by 2020. Ethanol Produced in PADD 5 increases to 30 TBD in 2010 (Ethanol supply produced in PADD 5 assumes all under construction ethanol plants are completed and 90% utilized by 2010)
- Incremental ethanol from outside PADD 5 is assumed to be sourced primarily from other PADDs and shipped to PADD 5. Imported ethanol may be an alternative if infrastructure (ports, etc) allow.
- As ethanol usage grows in the PADD 5 supply with flat demands, the estimated reduction in requirement for petroleum-sourced gasoline is about 143 TBD by 2020. This triggers lower imports and transfers.
- The significantly lower import/transfer levels may put significant downward pressure on gasoline prices relative to NYMEX and erode refinery margins. With very high operating costs for many PADD 5 refiners (especially California), this may threaten refinery sustainability.

Summary Observations on Changes in the Gasoline Supply & Demand Balance (con't)

- The implications of the reduced requirement for refinery produced gasoline can be best examined by observing the effect of lower demands for diesel fuel in 2008 (See slide 20). A collapse of the gasoline price vs NYMEX in PADD 5 would have material impact on PADD 5 refiner profits.
- While the outlook for gasoline demand in the AEO is relatively flat through 2020 due to CAFÉ standards impacts (and other initiatives), *an increase in demand of 1% per year would result in over 210 TBD additional PADD 5 gasoline demand by 2020.* This would require substantial increases in imports of both petroleum based gasoline and ethanol.
- Should EPA allow an increase in the ethanol content of E-10 to 13% (E-13), this would raise the requirement for ethanol (after enacted) by as much as 50 TBD in PADD 5 by 2011. This would further raise ethanol import needs and decrease required refinery supply.

Jet Fuel Forecast Supply & Demand

(TBD)

	2007	2012	2020	Change 2007-2020
Supply				
Refinery Production	404	416	420	16
Imports	112	34	92	(20)
Net PADD Transfers	6	16	16	10
Ethanol / Biodiesel				
Liquids from Biomass				
Total Supply	**522**	**466**	**528**	**5**
Non-PADD 5 Supply	*23%*	*11%*	*20%*	
Demand				
Consumption	507	450	512	5
Exports	15	15	15	0
Total Demand	**522**	**466**	**528**	**5**

Imports modified slightly in 2007 to eliminate inventory build or draw

Source: EIA

Summary Observations on Changes in the Jet Fuel Supply & Demand Balance

- Refinery production increases from 2007 due to slightly higher capacity and assumed 90% utilization.
- Jet fuel demands were significantly impacted by the 2008 recession. Jet fuel demands do not return to 2007 levels until 2020, and then increase significantly to 2030.
- AEO long term demand growth for jet fuel in the 2009 AEO is lower than the 2008 AEO based on (presumably) higher estimated energy prices.
- Net imports and PADD transfers of jet fuel into PADD 5 are estimated to decline in 2012 and 2015, then return to near 2007 levels by about 2020.
- Note that jet fuel demands are highly sensitive to both U.S. and global economic growth and may be significantly higher than the AEO forecast. *An increase of 1% in annual jet fuel demand growth from 2007 to 2020 would increase import/transfer requirements by 66 TBD by 2020.*

Distillate Fuel Forecast Supply & Demand

(TBD)

	2007	2012	2020	Change 2007-2020
Supply				
Refinery Production	539	555	568	29
Imports	30		23	(7)
Net PADD Transfers	29	38	44	15
Ethanol / Biodiesel	4	9	14	9
Liquids from Biomass		0.3	6	6
Total Supply	**602**	**602**	**655**	**53**
Non-PADD 5 Supply	*10%*	*6%*	*10%*	
Demand				
Consumption	569	570	622	53
Exports	33	33	33	0
Total Demand	**602**	**602**	**655**	**53**

Imports modified slightly in 2007 to eliminate inventory build or draw

Source: EIA

Summary Observations on Changes in the Distillate Supply & Demand Balance

- Refinery production increases from 2007 due to slightly higher capacity and assumed 90% utilization.
- Distillate demands in 2008 were also impacted by the recession, and AEO demand assumptions show recovery to 2007 levels by 2012. AEO long term demand growth for distillate in the 2009 AEO is lower than the 2008 AEO based on (presumably) higher estimated energy prices.
- Imports of about 67 TBD petroleum distillates are required by 2020 to meet demand forecasts.
- The AEO assumes that distillate supply in PADD 5 will be augmented by about 20 TBD biodiesel and distillates from biomass by 2020.
- Note that distillate demands are also highly sensitive to both U.S. and global economic growth and may be significantly higher than the AEO forecast. *An increase of 1% in annual distillate demand growth will raise import/transfer requirements by 74 TBD by 2020.*

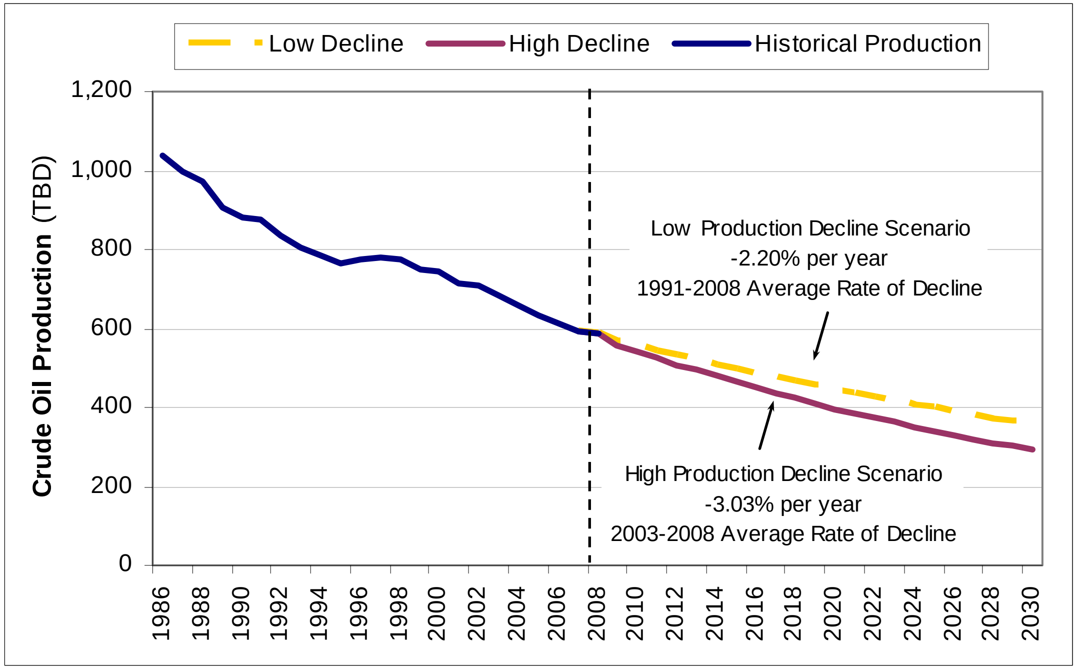
Summary Observations on Changes in the Product Supply & Demand Balance 2007-2020

- The tight supply & demand balance in PADD 5 is likely to be sustained over the period to 2020, although the recession is reducing near term import requirements of products
- As ethanol volumes increase in gasoline based on AEO assumptions there will be a transition from a significant influx of gasoline and blendstocks to an influx of ethanol. Regardless of whether the ethanol is produced in PADD 5 or not, the infrastructure needed to produce, store, transport and blend this volume of ethanol is not in place. If E-13 or higher is allowed, the concern increases.
- Moreover, the cellulosic volume assumed in the AEO in 2020 is about 140 TBD (See Appendix 2) while the RFS mandates almost 700 TBD by 2020. The AEO assumption is more realistic, but still requires that about 60 new cellulosic plants be built by 2020 (average capacity 36 bgy). Only one commercial plant of that size has been announced to date, to be streamed in 2012*
- The “influx” volumes of all products into PADD 5 assumes that despite reductions in petroleum gasoline required to meet demands, and short to mid term reductions in distillate and jet imports, that refining capacity will remain stable and in fact grow post -2020. ICF believes this is a very optimistic perspective given the high operating costs of most high complexity PADD 5 refiners
- If refining and biofuel capacity growth do not occur as forecast, or if demands increase above the 2009 AEO forecast (which may have been influenced by 2008’s very high crude prices), the fragile PADD 5 market may see even higher volatility in prices and supply than have been seen in recent years.

* Announcement from BP and Verenium, February 2009

Crude Oil Outlook

California Crude Oil Production Forecast is on a Steady Path Down…



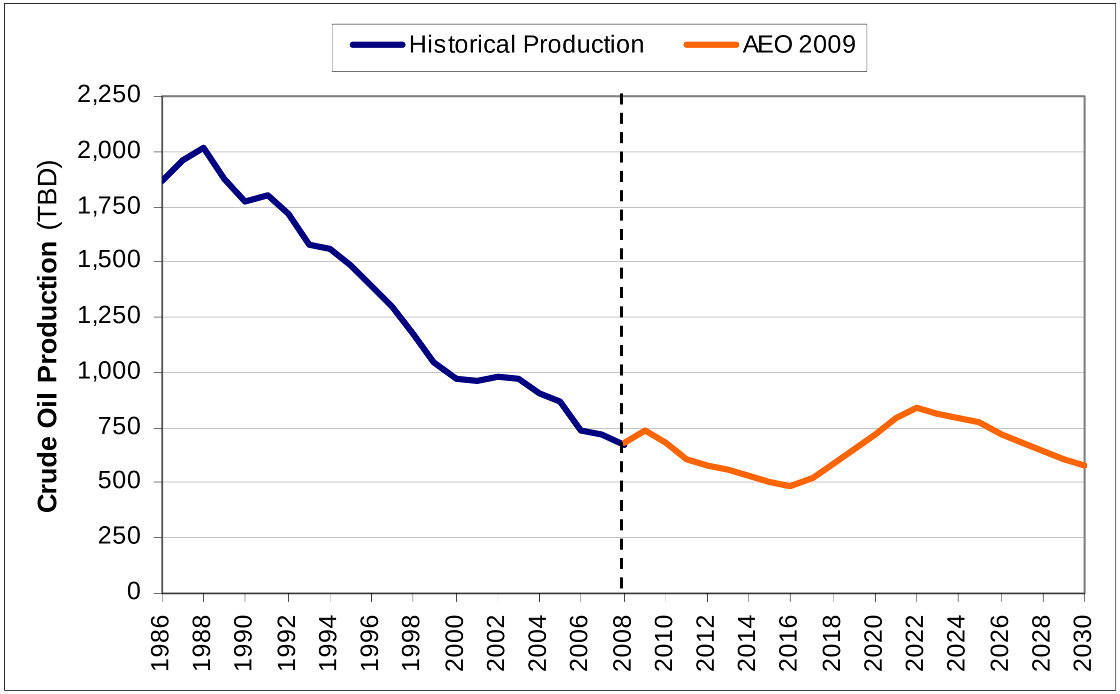
Source: EIA

*2008 data through September 2008

- California crude production has been on a steady decline since 1986
- Decline rate increased in the 2003-2008 period despite higher crude prices
- Forecast used in this study is based on the more recent 2003-2008 decline rate

Alaska Crude Oil Production Forecast

Shows Continued Decline over the Period, with an Increase in 2017-2022



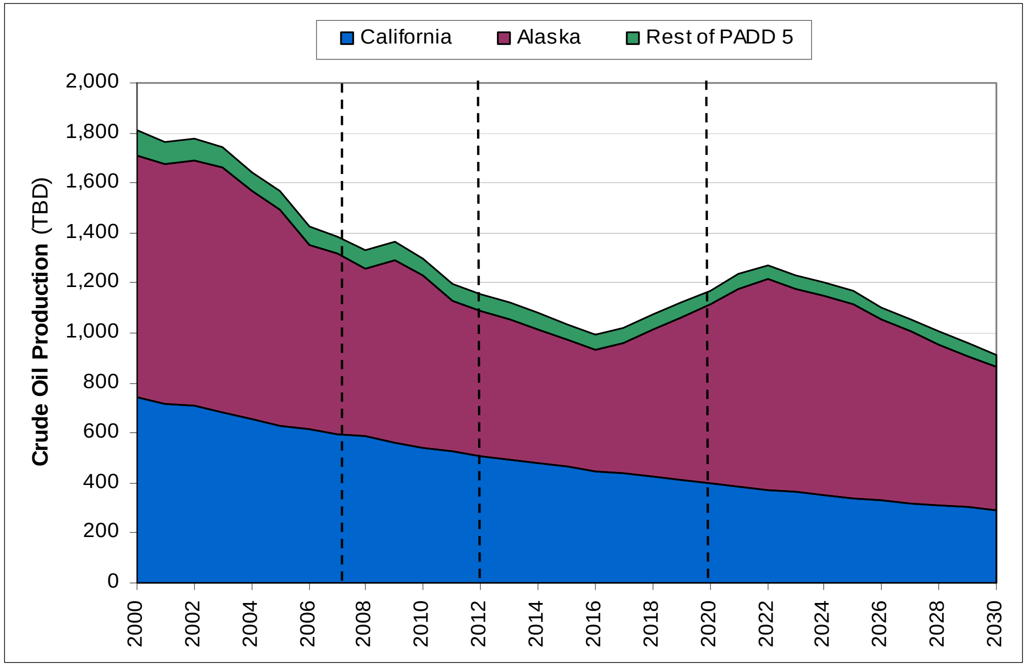
Source: EIA; AEO 2009 Reference Case

- Production from Alaska declines through 2016
- Moderate increase forecast in AEO due to primarily additional offshore supply estimated by EIA
- No production from ANWR assumed in the AEO outlook

- Increased production is due to the expected start-up of the Oooguruk, Nikaitchuq, Liberty, Qannik and Point Thomson fields
- EIA is also assuming (with MMS) that 5 new onshore and offshore fields will be discovered and put in production, with the largest volumes being offshore.

Overall PADD 5 Crude Oil Production Forecast

Declines rapidly thru 2016, then Increases



Rest of PADD 5 includes production in Arizona, Nevada, and Federal Offshore.

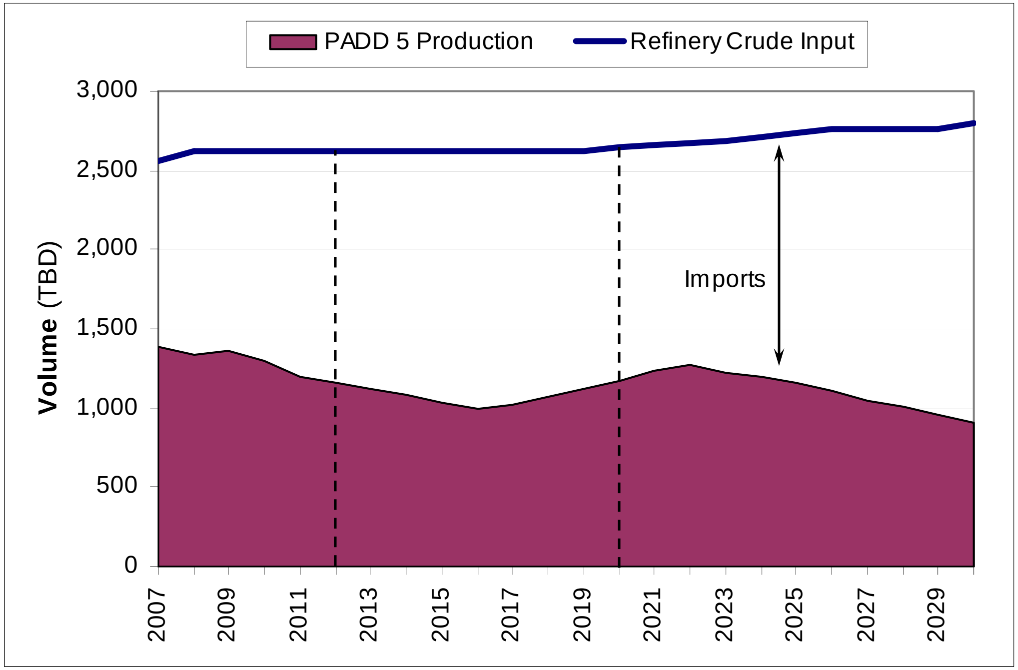
2003-2008 average rate of production decline used for California and Rest of PADD 5.

Source: EIA; AEO 2009 Reference Case

(TBD)	2007	2012	2020
Alaska	722	583	715
California	594	508	397
Rest of PADD 5	69	67	57
PADD 5 Total	1,385	1,158	1,169

- Overall crude production is forecast to decline by 216 TBD through 2020
- Most of the decline occurs in the period to 2012, as supply recovers somewhat in 2017 due to added Alaska production

PADD 5 Crude Oil Supply & Demand Outlook



(TBD)

	2007	2012	2020
Refinery Crude Input	2,560	2,623	2,647
PADD 5 Production	1,385	1,158	1,169
Imports	1,149	1,465	1,478

* 2007 adjustments and inventory changes were equal to a net supply contribution of 26 TBD from Petroleum Supply Annual 2007 Table 24.

Source: EIA AEO 2009

- Foreign Import levels will increase by over 300 TBD through 2020; Volume increase may be as much as 600 TBD if forecast Alaska growth does not occur
- Import volumes exclude ANS marine imports into LA, SF and Puget Sound ports, which amount to all ANS not used for Alaska demands

PADD 5 Estimated Crude Marine Receipt Trend

(TBD)

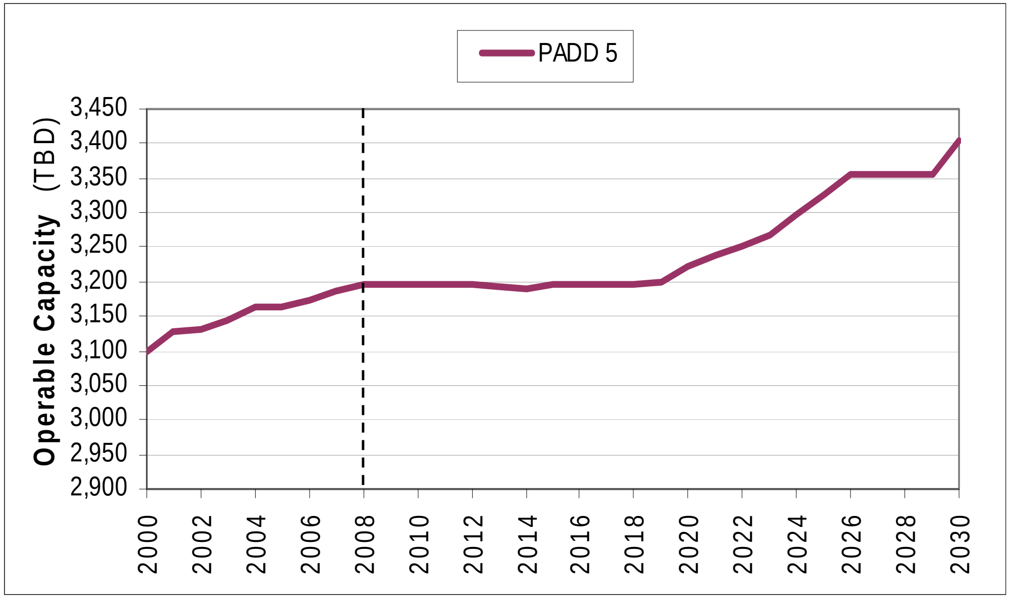
	2007	2012	2020	Change 2007-2020
Refinery Crude Input	2,560	2,623	2,647	87
California Crude Production	594	508	397	(197)
Canadian Pipeline Supply	126	126	126	0
Alaska Estimated Demand	121	115	126	5
Estimated Net Marine Supply	1,719	1,874	1,998	279

Source: EIA AEO 2009 demands and refinery input; 2007 Canadian Crude imports into PADD 5 (assumed all pipeline); 2007 actual California crude production declining at recent 2003-2008 trend.

- Based on forecast demand trends and refinery input assumptions, and assuming constant Canadian pipeline supply, Net marine deliveries of crude oil in PADD 5 should increase about 279 TBD by 2020.
- This increased volume would primarily be delivered into California ports, since it will replace reductions in California crude over the period.

Infrastructure

Operable Refinery Capacity Growth Forecast Shows Minimal PADD 5 Added Capacity to 2020



Source: EIA AEO 2009

- Growth in PADD 5 forecast by AEO is minimal in the 2007-2020 timeframe.
- The AEO supply & demand balance changes for gasoline over the 2007-2020 period portend weaker gasoline margins in PADD 5
- The minimal refinery capacity growth and announcements in the *high* margin 2003-2008 period indicate weaker margins will likely not support added capacity
- There is potential that weaker margins could cause some less competitive refining capacity to shut down and increase supply gaps over the period

Some Refinery Investment Is Occurring with a Focus on Improving Heavy Crude Processing and Yields of Premium Products…

- Analysis of publicly available sources shows a few projects are planned or underway to improve processing of heavy crude
- Ability to increase refining capacity in PADD 5 is complicated by permitting processes, current and pending legislation (e.g. Magnuson Act in Washington, potential LCFS in California, and others in place or under consideration), and uncertainty of future margins and regulations.
- Major new refinery expansion projects are under construction in Texas, Louisiana and Illinois

PADD 5 Biorefinery Capacity Shows Recent High Growth is Slowing

PADD 5 Ethanol Production Capacity
As of Feb 2009 (Million gallons per year)

	Online	Expected 2009+
Arizona	55	--
Nevada	--	--
Alaska	--	--
California	139.5	105
Hawaii	--	--
Oregon	148	--
Washington	--	55
Total	342.5	160

Source: Renewable Fuels Association

PADD 5 Biodiesel Production Capacity
As of Feb 2009 (Million gallons per year)

	Existing	Expected 2009+
Arizona	19	--
Nevada	6	101
Alaska	--	--
California	88	10
Hawaii	2	--
Oregon	9	--
Washington	264	--
Total	387	111

Source: National Biodiesel Board, Biodiesel Magazine

- Ethanol capacity growth in 2009 shows an additional 160 million gallons per year (11 TBD) added supply. These are facilities under construction. The current recession and the credit situation have slowed new announcements.
- Biodiesel current capacity and new capacity shown from the National Biodiesel Board is likely overstated. Information from Washington state energy officials indicates actual capacity in Washington may only be 150 mgy currently due to closures.
- AEO Outlook shows growth in biodiesel to 138 mgy (9 TBD) in PADD 5 by 2012 with no further changes. ICF study is consistent with AEO Outlook. Economics of biodiesel plants are heavily influenced by feedstock cost, with minimal indication of change.

Logistics: Pipelines & Ports

Crude Oil:

- One external pipeline (Kinder-Morgan’s Trans Mountain pipeline into Puget Sound refiners)
- All other non-California crude oil must be transported by ships into West Coast ports and Hawaii.
- Declining California crude supply and stable refinery capacity/throughput forecast in AEO will require significant net growth of foreign and ANS crude into California ports
- Capability to receive and store crude in a timely manner will become increasingly critical to sustaining refinery operation and reliable product supply

Products:

- The PADD 5 states (Lower 48) can be accessed by the Chevron pipeline from Utah and Yellowstone system from Montana (into the Northwest) and the Longhorn/Kinder-Morgan system into Arizona from Texas/New Mexico. Holly Corporation is constructing a 60 TBD pipeline from Utah into Las Vegas to start up in 2010.
- The existing pipelines provided about 6% of total G+D supply into PADD 5, primarily gasoline. The Holly pipeline may provide some incremental pipeline supply, but it may also result in fewer barrels being shipped on current pipelines, depending on economics. Utilization of the pipeline infrastructure may decline if PADD 5 refinery utilization remains high and ethanol volumes in PADD 5 gasoline increase per AEO

Logistics: Pipelines & Ports (Cont'd)

Products:

- Products are imported into key U.S. West Coast ports, primarily California from both foreign and domestic sources. Volumes by marine were about 291 TBD in 2007, with exports of 95 TBD. Volumes declined in 2008 with lower demands (although exports grew to partially offset the decline). Port infrastructure (storage, discharge locations, pipelines into refineries & terminals) is critical in California to enable basic supply and demand balancing and to respond to disruptions.
- Ethanol is currently supplied by local PADD 5 supply and unit train volumes moving from the Midwest to Carson, Ca and then redistributed by rail or truck. Ethanol volume in PADD 5 is estimated to increase from 79 TBD in 2007 to 200 TBD by 2020, which will require significant infrastructure improvements.

Key Infrastructure Issues

- The changes in supply and demand for PADD 5 which stem from analysis of the AEO Outlook are substantial. The conversion from an essentially all refinery-produced gasoline supply and distribution supply chain to a region which will require about 12-13% of fuel supply by 2020 from a wholly separate supply chain is a significant transition. Failure to address these issues will increase the risk of greater price volatility due to supply challenges.
- Primary exposure areas are:
  - Ethanol Production, Storage, Distribution & Transport must be developed. While PADD 5 has some ethanol production capacity and may be able to produce 30 TBD by 2010, required volumes by 2012 and 2020 will grow from 79 TBD in 2007 to 160 TBD and 200 TBD, respectively to meet forecast demands. These would grow rapidly at ethanol blends over 10%.
  - Port facilities, particularly in California, will come under additional stress to receive crude oil, jet fuel and diesel, and ethanol imports. Facilities must be expanded and better integrated with the new downstream supply system. Coordination between the oil industry, states, and Ports is essential to insure adequate dock and tankage capacity, and prioritization for any new required pipeline facilities to transport additional fuels (including ethanol) into the distribution system.

PADD 5 Dependence on Petroleum Imports Increases with AEO Assumptions

(TBD)

Mode of Shipment	Crude Oil	Motor Gasoline	Ethanol	Jet Fuel	Distillate Fuel	Residual Fuel	Total
Marine	1,023	107	3	115	34	35	1,317
Pipeline	126	135		6	28		295
Rail			69				69
2007 Non-PADD 5 Supply	**1,149**	**242**	**72**	**121**	**62**	**35**	**1,681**
2020 Non-PADD 5 Supply	**1,478**	**35**	**170**	**108**	**67**	**71**	**1,929**
2020 @ 1% higher demand	**1,478**	**218**	**196**	**174**	**141**	**76**	**2,283**

Source: EIA, ICF

- Total dependence increases by 248 TBD from 2007 to 2020, and an additional 354 TBD if AEO demands grow 1% more annually than forecast
- PADD 5 states, in particular California, must be prepared to handle higher levels of ethanol transfers and imports, produce more in-region biofuel and other alternative supplies than forecast in this study, and deploy infrastructure to enable distribution of those products AND maintain/improve oil infrastructure.

Ethanol Expansion Infrastructure Issues:

Production:

- Additional PADD 5 ethanol capacity beyond 2010 forecast must be developed and integrated (both corn based and cellulosic). Ethanol pathways to market must be identified and enabled.

Receipts & Distribution:

- Port facilities must be expanded with dedicated ethanol storage and separate pipelines.
- Rail receiving centers must be increased to provide additional ethanol receipt locations and better distribution.
- Integration of ethanol from rail facilities (currently in Carson, Ca) to the gasoline terminal distribution system must be improved from the current trucking operation. Potential use of ethanol pipelines to access major industry terminals may be required for adequate control of supply.

Terminals:

- Terminals which hold petroleum based gasoline may require tank conversions to accommodate higher ethanol volumes & inventory. Permitting for these changes must be expedited.

Service Stations:

- E-85 levels identified in the AEO will require significant infrastructure changes in service stations, as well as vehicle fleet turnover to flex-fuel.

Regulatory Outlook

Regulatory Issues in the AEO Impacting Fuels

- The Annual Energy Outlook is put together based on enacted regulations and legislation and known future legislation.
- The 2009 AEO reflects the EISA Act of 2007 which has mandated higher automotive CAFÉ standards and biofuel usage. EIA has incorporated these regulations in the new AEO, but has not reflected the full biofuel impact by the mandated year (2022) based on an assessment of technology commercialization.
- The AEO did not reflect any legislation for carbon management or for Low Carbon Fuel Standards (LCFS) which are under review in the U.S. Congress, and which some states have passed or are considering.
- Other state and regional entities (such as the Western Climate Initiative) are actively developing policies and regulations on carbon, LCFS and/or biofuel requirements.

Regulatory Issues in the AEO Impacting Fuels

- The intent of the EISA changes as well as pending, proposed, or passed legislation at the Federal and State levels is target to reduce dependence on petroleum based fuels through more efficient vehicles and substitution of less carbon intensive fuels (electric vehicles and hybrids, CNG/hydrogen, biofuels)
- This transition is planned to reduce oil dependence and provide mechanisms to reduce CO2 levels in the atmosphere
- Therefore, the AEO outlook reflects a movement in this direction primarily through CAFÉ standards and biofuel mandates. The implications of more rapid deployment of electric vehicles and alternative fuels would mean lower demands than in the AEO for petroleum products (primarily gasoline)
- For refiners, this outlook creates significant question on long-term investment decisions and refinery sustainability. These questions are especially significant in PADD 5 states such as California which have a number of legislative initiatives which, if successful, could reduce future demands for petroleum products in the region

Federal and Regional Climate & Regulatory Initiatives Facing PADD 5

- The new Administration has signaled an intent to move forward with legislation to establish a cap and trade system to reduce greenhouse gas (GHG) levels. The specific nature of final legislation is not resolved, however the current version of the Lieberman/Warner/Boxer bill may be a model.

- Regionally, the Western Climate Initiative (WCI) is moving forward to implement a cap and trade system on transportation fuels in a group of Western States and Canadian provinces.

- The intent of these mechanisms is to drive incentives to reduce carbon emissions from transportation fuels and provide incentives to develop new technologies and alternative fuels to displace petroleum based supply.

- ICF conducted a study for API of the Lieberman/Warner *Climate Security Act of 2007* (an early version of the current potential legislation) which estimated that U.S. refineries could become increasingly disadvantaged as estimated allowance costs increased. ICF estimated that PADD 5 refinery input might decline by 2020 by about 240 TBD from recent levels, and PADD 5 might then shift imports of crude oil to more imports of products.

Federal and Regional Regulatory Climate Initiatives Facing PADD 5 (Cont'd)

- Potential reductions in sulfur level and particulates in bunker fuels were adopted by the International Maritime Organisation (IMO) in 2008, along with possible EPA. Bunker fuel sulfur levels must be reduced to 0.1% sulfur by 2015 in designated "SECA*" areas by 2015. All bunker fuels worldwide must be at 0.5% sulfur or lower in open waters by 2020.
- It is very likely the U.S. EPA will endorse and perhaps accelerate the timing of U.S. SECA designations and implementation of lower sulfur bunler fuel usage in coastal waters. Note that the "California Ship Fuel Rule" (section 2299.2, title 13 of California's Code of Regulations (CCR)) will lower Marine Gas Oil and Marine Diesel to 1.5 and 0.5% sulfur July 2009, and all Marine fuels to 0.1% sulfur by 2012 within 24 miles of the California coast.
- Potential impact on PADD 5 refiners could be significant since investment to lower sulfur levels in residual fuel, or to upgrade via coking are very costly and may have GHG costs that would further exacerbate economics.
- An alternative to use marine diesel to displace bunker fuels in SECA regions would result in incremental diesel imports and exports of higher sulfur residual fuel. Both actions erode refinery economics and increase port infrastructure

* SECA is a sulfur emissions control area

California Regulatory Issues

- 2006 Bioenergy Action Plan: Establishes goals to have a certain percentage of California's biofuel usage (ethanol, biodiesel, biobutanol, etc) produced within the state. The goals are simply targets and are not binding. Biofuels in-state production goals increase from a minimum 20% in 2010 to 40% in 3030 and 75% in 2050. Usage targets are also set for 2010 at 0.93 B gasoline gallon equivalents, increasing to 1.6 bgge in 2020 and 2.0 bgge in 2050.

- 2006 AB 2076: Establishes a goal (not a mandate) to increase use of alternative fuels to 20% of on-road transportation fuel use by 2020 and 30% by 2030. Alternative fuels would include biofuels, CNG, Hydrogen, etc.

- 2007 AB1007 or State Alternative Fuels Plan: AB1007 concluded and established that the feasible goals for alternative fuels use in on and off-road (excluding air, rail and marine) applications was 9% in 2012, 11% in 2017 and 26% in 2022. This essentially brings forward the AB2076 goals. Again, the goals are not mandated.

California Regulatory Issues (Cont'd)

- 2007 AB 118 Alternative & Renewable Fuels and Vehicle Programs: AB 118 authorizes the Energy Commission and CARB to provide, upon appropriation by the Legislature, approximately $120 million and $80 million (respectively) annually to a wide range of companies and institutions to develop and improve alternative and renewable low-carbon fuels, expand infrastructure, etc. Basically AB118 establishes funds to enable implementation of alternative fuels and meeting overall goals

.

- Governor's E.O. S-01-07, LCFS (Adoption in 2009, Implementation in 2010)
  1. That a statewide goal be established to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020 ("2020 Target").
  2. That a Low Carbon Fuel Standard ("LCFS") for transportation fuels be established for California.

- 2006 AB32 authorizes CARB to develop regulations to reporting, verification and reduce state GHG Emissions to 1990 levels by 2020. The scoping plan containing main strategies to achieve these goals (which are economy wide, not just for petroleum facilities) was approved December 2008. These regulations will likely be aligned with LCFS implementation and possibly Federal and Regional GHG emissions management programs.

Oregon Regulatory Issues

- HB 2210 (aka: E-10 Mandate) is effective when in-state ethanol plant capacity reaches 40 MMgal/year. 10% of all gasoline sold must be ethanol.
- HB 2210 (aka: B2 Mandate) is effective when in-state production from regional feedstock reaches 5 MMgal/year. 2% of diesel sold must be biodiesel.

Washington Regulatory Issues

- At least 2% of total gasoline sales, measured on a quarterly basis, must be ethanol by December 1, 2008. Ethanol content between 2% and at least 10% may be required if Ecology determines it will not jeopardize air quality standards for ozone pollution, and Agriculture determines instate raw materials are available to support economical production. *(RCW* 19.112.120)*
- At least 2% of the total annual diesel sales must be biodiesel by November 30, 2008. At least 5% must be biodiesel when Agriculture determines instate oil seed crushing capacity and feedstocks can satisfy a 3% requirement. *(RCW 19.112.110)*
- Washington State officials estimate current gasoline ethanol content statewide is 8-9%
- Washington H.B. 1718, Section 248 requires CTED, Ecology, agriculture and transportation departments to evaluate and implement LCFS requirements by December 2011, but only after learning from California's experience.

* Revised Code of Washington

Hawaii Regulatory Issues

- Act 240 SLH 2006 (aka: SB 2957): 10% of on-road transportation fuels sold must be alternate fuels by 2010, 15% by 2015, and 20% by 2020. Most gasoline currently sold in Hawaii contains 10% ethanol, however biodiesel usage is minimal.
- Act 234 requires that GHG emission levels be reduced to 1990 levels by 2020. The GHG Emission Reduction Task Force appointed under Act 234 will compile a plan to achieve the reduction, with a goal to adopt rules by Dec 31, 2011 that establish GHG emission limits to be achieved by Jan. 1, 2020.
- Memorandum of Understanding (MOU) between the State of Hawaii and US Dept. of Energy (aka: Hawaii Clean Energy Initiative): Sets a goal for 70-percent of energy used in electricity and transportation be derived from clean, renewable energy by 2030

Appendix 1:

2008 and 2009 AEO Demand Comparison

(TBD)		2008 AEO			2009 AEO		
	2007	2012	2020	Change 2007-2020	2012	2020	Change 2007-2020
Finished Motor Gasoline	1,626	1,674	1,788	165	1,621	1,609	(17)
E85	*0.2*	*0.2*	*227.3*	*227.1*	*0.2*	*64.0*	*63.8*
Finished Motor Gasoline (Quadrillion Btu)	*3.0388*	*3.0962*	*3.2054*	*0.1666*	*2.9948*	*2.9460*	*(0.0928)*
Motor Gasoline Blending Components	1,547	1,515	1,444	(99)	1,461	1,404	(143)
Ethanol	79	160	334	255	160	200	120
Liquids from Biomass	0	0	10	10	0	5	5
Jet Fuel	507	580	666	159	450	512	5
Distillate Fuel Oil	568	611	676	108	570	622	54
Petroleum-derived	564	602	655	91	560	602	38
Biodiesel	4	9	9	5	9	14	9
Liquids from Biomass	0	0	12	12	0	6	6
Residual Fuel Oil	157	151	156	(1)	173	178	21
TOTAL	**2,858**	**3,017**	**3,286**	**431**	**2,814**	**2,921**	**63**
Petroleum-derived	2,775	2,848	2,920	149	2,644	2,696	(78)
Renewables	83	169	365	282	170	225	141

Italicized items are not part of the breakdown of finished motor gasoline by component volumes.

Forecasted volumes for ethanol and motor gasoline blending components are based on national-level blending proportions derived from AEO-forecasted energy content of ethanol in E85 and motor gasoline (Reference Case Table 17).

Forecasted volumes for biodiesel and liquids from biomass are based on national-level blending proportions derived from AEO-forecasted supply volumes (Reference Case Table 11). As advised by EIA staff, the following are assumed for liquids from biomass: 40% naphtha streams to be blended into gasoline, 60% distillate streams.

Source: EIA AEO 2008

Appendix 2
Biofuel Volumes in 2009 AEO

(TBD)

	2007	2012	2020	2030
Liquids from Biomass	0.0	3.5	74.8	327.6
Biodiesel	32.0	70.2	98.4	124.6
Ethanol - Net Imports	21.6	-5.9	43.3	485.5
Ethanol - Domestic from Cellulose	0.0	9.8	140.6	330.9
Ethanol - Domestic from Corn	403.4	932.4	1,094.8	1,117.2
Total	**457.0**	**1,010.1**	**1,451.9**	**2,385.7**

Source: 2009 AEO

BGY

AEO Volumes	**7.0**	**15.4**	**22.3**	**36.6**
RFS Mandate (EISA 2007)		**15.2**	**30.0**	**36.0**

Appendix 4 – EEA, Inc. – Energy Economy Ratios for Alternative Fuel Vehicles

WSPA
Western States Petroleum Association

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine H. Reheis-Boyd
Executive Vice President and COO

February 4, 2009

Mr. Dean Simeroth, Ms Renee Littaua, Mr. John Courtis
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
Via electronic mail

Re. WSPA Comments on CARB's LCFS Energy Economy Ratios

Dear Mr. Simeroth, Ms. Littaua, Mr. Courtis:

The Western States Petroleum Association (WSPA) recently sponsored an evaluation of the energy economy ratios (EERs) that the California Air Resources Board (CARB) staff is proposing to use in the Low Carbon Fuel Standard (LCFS) regulations. The results of that study, conducted by Energy and Environmental Analysis, Inc. (EEA), are documented in the attached report.[1]

A summary of the results of EEA's analysis is presented below, followed by additional comments on the development of EERs for the LCFS. WSPA would appreciate you posting both our cover letter and the report to the LCFS public comment portion of your website.

Alternative EERs Developed by EEA

As used in the LCFS regulation, the EER reflects the ratio of the fuel economy of an alternative fuel vehicle to the fuel economy of a gasoline or diesel vehicle it replaces. A review of EEA's report reveals two primary factors that were not fully accounted for in CARB's development of their proposed EERs. Although these factors are often ignored when comparisons of alternative fuel vehicles to conventional gasoline and diesel vehicles are made, it is important to account for them to fairly compare fuels and vehicles:

- Comparisons must be made based on ***on-road fuel economy*** rather than fuel economy derived from FTP-based laboratory testing. This is particularly important for battery electric vehicles which can be significantly impacted by ambient temperatures, use of air conditioning and heating, road grade, and other factors not typically accounted for in laboratory testing. EEA's analysis accounted for some of these effects by using fuel economy adjustment factors recently developed by EPA to better reflect on-road operation when fuel economy is reported on fuel economy labels. In most instances, there was fuel economy data available from actual on-road testing to validate this approach.

[1] "Energy Economy Ratios for Alternative Fuel Vehicles," Prepared by Energy and Environmental Analysis, Inc. for the Western States Petroleum Association, January 2009.

- Comparisons must be made based on vehicles with ***similar attributes*** (e.g., acceleration, aerodynamic drag, low rolling resistance tires, etc.) in order to separate vehicle effects from fuel effects. EEA's analysis accounted for this effect by making adjustments to conventional vehicle fuel economy estimates for differences in attributes and power among conventional and alternative fuel models.

We have summarized the CARB EERs from the December 2008 draft regulation and the EEA recommended EERs in Tables 1 and 2 for light-duty and heavy-duty vehicles, respectively. [A revised set of EERs for light-duty vehicles was presented by CARB staff at the January 30, 2009 workshop. However, those estimates are not included in Table 1 because they are on a different basis than CARB's December 2008 EERs and the EEA estimates that are compared in the table. This is discussed more fully under "Additional Comments on EERs for the LCFS."]

Note that EEA did not perform a thorough analysis of EERs for light-duty E85, CNG, and LPG vehicles as their experience with data from those fuels suggests the EER values are not likely to differ from 1.0 by more than ±0.05. Budget and time constraints limited the evaluation of heavy-duty EERs to diesel hybrid, CNG, and hydrogen fuel cell vehicles (FCVs).

Several points are worth noting with respect to Tables 1 and 2:

- The EERs developed by EEA are lower than those currently in the December 2008 draft LCFS regulations for nearly all fuels and technologies. This is a result of EEA's more rigorous treatment of on-road fuel economy and differences in attributes among vehicle types.

- For light-duty battery electric vehicles (BEVs), the EER of 3.4 recommended by EEA is 15% lower than CARB's estimate of 4.0, even though EEA stated that 3.4 reflects an "optimistic EER for the 'best' EVs" included in their study.

- For light-duty plug-in hybrid electric vehicles (PHEVs), the EER under all-electric mode calculated from EEA's recommendations is slightly higher than that proposed by CARB staff.

- For hydrogen FCVs, both light-duty and heavy-duty EERs recommended by EEA are lower than CARB's estimates. Also, the December 2008 draft regulations assign the same EER to hydrogen FCVs and internal combustion engine vehicles (ICEVs). This makes no sense and is not supported by any data. As noted by EEA, these engines do not even offer an EER of 1.0 on a comparable attribute basis and should not be grouped with FCV models.

- A significant difference highlighted by the EEA analysis is the EER for heavy-duty CNG vehicles. Given the inherently better efficiency of diesel versus spark-ignition engines, CARB's initial selection of 1.0 for CNG heavy-duty vehicles was somewhat surprising. As noted in the EEA report, the recommended EER of 0.7 is based on the assumed use of stoichiometric operation to meet NOx standards. If lean-burn engines are produced that meet the 2010 NOx level, or if systems utilizing a diesel/natural gas fumigation approach are developed, the EER of 0.7 should be revisited to reflect the potential efficiency improvements of those systems.

Additional Comments on EERs for the LCFS

WSPA members had a number of additional comments on the development of EERs for the LCFS. These are summarized below.

- A significant shortcoming in the development of EERs is the lack of data on production-ready, alternative fuel vehicles such as PHEVs and hydrogen FCVs. As a result, it is imperative that CARB re-evaluate the EERs when data are available on OEM production vehicles (accounting for on-road fuel economy and differences in attributes as recommended by EEA).

- As noted above, a revised set of EERs for light-duty vehicles was presented by CARB staff at the January 30, 2009 workshop. It is our understanding that those EER estimates include an adjustment for projected fuel economy improvements to the baseline conventional vehicles to account for AB 1493 and federal CAFÉ standards. Such an adjustment is appropriate and should be included in EER estimates developed for future model year vehicles. However, if that adjustment is applied to conventional gasoline vehicles, every effort should be made to ensure that the alternative fuel vehicles being analyzed also reflect the technology anticipated for the same timeframe as the conventional vehicle estimates. In this way, an "apples-to-apples" comparison is made.

- Another issue related to the selection of an appropriate baseline vehicle arises when evaluating EERs for PHEVs. The ratio of operation on electric power to operation on gasoline/diesel is appropriate since it is clear that electricity is displacing the fuel that would have been used if the vehicle was run in "conventional" hybrid electric vehicle mode. In the case of BEVs and FCVs, the baseline vehicle (i.e., the denominator in the EER calculation) used in CARB's December 2008 EER estimates and in the EEA study is a conventional gasoline vehicle. However, given future fuel economy requirements, it may be more appropriate to use a conventional hybrid electric vehicle as the baseline vehicle since that is likely what would be displaced by a BEV or FCV. In any case, the selection of baseline vehicle technology should change moving forward to reflect the improved fuel economy of the new conventional vehicle fleet at the time the alternative fuel vehicles are introduced.

- EEA's analysis of EERs for "blended" PHEVs brings up an interesting question about how best to evaluate the EER for the electricity used during the charge-depleting mode when the gasoline or diesel engine can turn on and off in response to power demand. If this configuration of PHEV is ultimately marketed, CARB will need to develop guidance on how to estimate EERs for these vehicles; it should not be simply assumed that they would have the same EER as an extended-range PHEV or a BEV.

- Expanding on the issue of electricity used in PHEVs (and BEVs), it is imperative that CARB require documentation that electricity was actually used to power the vehicle. This is very important in the case of PHEVs where there is no operational requirement that the vehicle be plugged in to run.

- Recent research suggests that GHG emissions associated with lithium-ion battery materials account for 2% to 5% of lifecycle emissions from plug-in hybrids.[2] Previous LCA studies have

assumed that vehicle manufacturing emissions are negligible and can generally be ignored. However, for the case of BEVs and PHEVs, we recommend that CARB staff verify that battery manufacturing emissions are negligible and can be ignored for the LCFS. If not, this effect would probably best fit as an adder to the well-to-tank estimates for electricity generation and not necessarily in the EERs. Similarly, the energy used to make 10,000 psi tanks for hydrogen storage can be significant.

Table 1
Comparison of CARB and EEA Energy Economy Ratios for Light-Duty Vehicles (Fuels that Displace Gasoline)

Fuel/Technology	CARB EER	EEA EER
Gasoline/Hybrid	1.7	1.3
Electricity/BEV	4.0	3.4[a]
Electricity/PHEV	2.4	2.6 (Extended Range PHEV)[b]
Hydrogen/FCV	3.0	2.3
Hydrogen/ICEV	3.0	< 1[c]

[a] Note that the value of 3.4 for BEVs is characterized by EEA as an "optimistic EER for the 'best' EVs" included in their study.

[b] The value of 2.6 was calculated by dividing EEA's EER estimate on all-electric charge-depleting mode (3.4) by their estimate under range-extender mode (1.32). EEA also estimated EERs for "blended" PHEVs under both charge-depleting mode (2.1) and charge-sustaining mode (1.2). However, as noted in the EEA report, the EER estimate under charge-depleting mode is a strong function of trip distance. Additionally, operation under charge-depleting mode for this type of hybrid includes some engine operation. Thus, the implied EER for this technology of 1.8 (i.e., 2.1 divided by 1.2) underestimates the actual EER when only electricity is used to power the vehicle.

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[2] Samaras, C. and Meisterling, K., "Life Cycle Assessment of Greenhouse Gas Emissions from Plug-in Hybrid Vehicles: Implications for Policy," *Environmental Science and Technology*, **2008**, 42(9), pp 3170-3176.

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[c] Although an EER was not specifically estimated for hydrogen ICEVs, the EEA report concluded that these engines do not even offer an EER of 1 on a comparable attribute basis and should not be grouped with FCV models.

Table 2
Comparison of CARB and EEA Energy Economy Ratios for Heavy-Duty Vehicles (Fuels that Displace Diesel)

Fuel/Technology	CARB EER	EEA EER
Diesel/Hybrid	--	1.3
CNG/ICEV	1.0	0.7
Hydrogen/FCV	1.9	1.6
Hydrogen/ICEV	1.9	< 1[a]

[a] Although EERs were not specifically estimated for hydrogen ICEVs, the EEA report concluded that these engines do not even offer an EER of 1 on a comparable attribute basis for light-duty vehicles. Their performance relative to diesel heavy-duty vehicles would be expected to be even worse.

We hope you find this information useful in the development of the LCFS. Our members would be happy to meet with you and your staff.

If you have any questions or need clarification please don't hesitate to contact me at this office or Gina Grey of my staff at (480) 595-7121.

Sincerely,

Catherine H. Reheis-Boyd

c.c. M. Scheible, ARB
B. Fletcher, ARB
G. Grey, WSPA

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

ENERGY ECONOMY RATIOS FOR ALTERNATIVE FUEL VEHICLES

FINAL REPORT

Prepared for:
Western States Petroleum Association

January 2009

LIST OF ABBREVIATIONS

ARB	Air Resources Board
BEV	Battery Electric Vehicle
CNG	Compressed Natural Gas
CVT	Continuously Variable Transmission
EEA	Energy & Environmental Analysis
EER	Energy Economy Ratio
EPA	Environmental Protection Agency
EPS	Electric Power Steering
EREV	Extended Range Electric Vehicle
EV	Electric Vehicle (synonymous with BEV)
FTP	Federal Test Procedure
FCV	Fuel Cell Vehicle
HEV	Hybrid Electric Vehicle
HWFET	Highway Fuel Economy Test
INL	Idaho National Laboratory
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
PHEV	Plug-in Hybrid Vehicle
UDDS	Urban Dynamometer Driving Schedule

Introduction

The Air Resources Board is developing regulations for a Low Carbon Fuel Standard (LCFS). One factor in determining the carbon intensity of a specific fuel is the benefit in terms of the vehicle energy efficiency relative to the energy efficiency of a gasoline or diesel vehicle. The Energy Economy Ratio (EER) for a particular vehicle/fuel type combination is developed based on a "tank-to-wheels" comparison of fuel economy, and ARB has utilized data on the EER from either the TIAX report to the California Energy Commission, or from some comparisons using data generated by the ARB Mobile Source Control Division.

EEA examined the EER data in the LCFS draft regulation and their sources and concluded that the EER computations used in the LCFS did not account for several factors. First, it was not clear if the EER data was determined on a pump to wheels or tank to wheels comparison since for several fuels like CNG, LNG and Hydrogen, substantial energy is lost in compression or liquefaction energy. Different vehicles use different storage pressures that are vehicle (tank) design dependent and it was not clear how these differences are accounted for, but this issue is not addressed in this report. Similarly, recent research has indicated that GHG emissions associated with Li-ion battery materials account for 2% to 5% of lifecycle emissions from plug-in hybrids;[3] this factor also was not addressed in this report. Second, the EPA city and highway dynamometer (dyno) tests for fuel economy have known shortcomings in representing vehicle on-road fuel economy, and the EER values should represent on-road fuel economy ratios. The difference between EPA dyno based fuel economy and on road fuel economy depends on the vehicle's fuel economy reduction associated with the use of accessories such as air-conditioning and heating, aggressive driving, hot or cold ambient temperatures, etc. Different vehicle types react quite differently to these factors and comparisons of the official EPA city/highway fuel economy to derive EER values can be misleading. Third, the choice of vehicles to be compared to develop the EER can have a large effect if the base vehicle and the alternative fuel vehicle do not share the same interior room and performance attributes and differ in technology content unrelated to the use of alternative fuels. For example, most electric vehicles have much lower acceleration performance, and feature high pressure low rolling resistance tires, underbody covers and other aerodynamic aids, and other features that can be easily added-on to a conventional gasoline vehicle.

This report attempts to address the second and third issues by using on-road or equivalent fuel economy for all light-duty alternative fuel vehicle types and correcting for some significant technology

[3] Samaras, C. and Meisterling, K., "Life Cycle Assessment of Greenhouse Gas Emissions from Plug-in Hybrid Vehicles: Implications for Policy," *Environmental Science and Technology*, 2008, 42(9), pp 3170-3176.

differences between the conventional vehicle used as a baseline and the alternative fuel vehicle. The analysis is not as precise as desirable since the technology characteristics of many alternative fuel vehicles had to be obtained anecdotally from manufacturer representatives as these data are not published. Nevertheless, the resulting EER values computed are more accurate than those currently used by ARB in the LCFS regulation. Although the LCFS does not report a hybrid vehicle EER (since it uses gasoline), we have also included this vehicle technology to validate the EPA correction factor methodology and provide ARB additional information on estimating future vehicle GHG emissions. (ARB does, for example, calculate the EER of the Chevy Volt in hybrid mode). In addition, we have not evaluated the EER values for E85, CNG and LPG fueled vehicles where the ARB has selected a value of 1 for the EER since our experience with the data on such vehicles suggests that the actual EER values are not likely to differ from 1 by more than $\pm$ 0.05.

An analysis of EER values for heavy-duty vehicles is also provided. In this case, the only vehicles in commercial use are CNG/LNG trucks and buses, and hybrid buses with both series and parallel designs. A few prototype fuel cell buses are in operation and preliminary energy economy data from these vehicles was also obtained. The National Renewable Energy Laboratory (NREL) has been tracking and evaluating new propulsion systems in heavy duty vehicles for more than 10 years using an established and documented evaluation protocol, and NREL databases on these evaluations offer the most complete and accurate data sources available. We have used data from NREL evaluations supplemented by two reports from other sources that have conducted evaluations with the same rigor as NREL.

Methodology

In order to develop appropriate Energy Efficiency Ratios (EER) for light-duty vehicles, we used a four step methodology to develop an EER based on ‘on-road’ or real-world fuel economy, as follows:

1. Literature search for alternative fuel vehicle fuel economy test results in real world conditions. In cases where the test data from objective government sources were unavailable, EEA incorporated data from fuel economy evaluations reported by manufacturers or other public sources. In cases where multiple data sources were found, the results were compared across sources for consistency.

2. Selection of comparable conventional vehicle models for comparison. In many cases this exercise was straight forward since several advanced technology vehicles are based on conventional gasoline vehicle platforms. When an alternative fuel vehicle was unique, EEA selected comparable gasoline models based on similar market class and interior room. On-road

fuel economy for conventional vehicles was estimated using the new EPA "5-cycle" based correction factors (described below) to the standard city/highway test results.

3. Adjustments of conventional vehicle fuel economy for attribute and power differences among conventional and electrified models.
4. Determination of EERs.

Out of four types of electrified light duty vehicle technologies, only HEVs are currently commercially available in the US market. The US EPA reports fuel economy data for all light duty vehicles in the Fuel Economy Guide[4], but the key question for this analysis is whether the fuel economy values reported in the Guide represent fuel economy under real world driving conditions.

The EPA recently revised the fuel economy adjustment procedures through new Fuel Economy Labeling regulations to better represent real world fuel economy. The new adjustments were published in December 2006[5] and take into account, more completely, real world factors that impact fuel efficiency but are missing from the city and highway cycles used for the standard fuel economy test– specifically, higher speeds, more aggressive driving, the use of air conditioning (A/C) and effect of cold temperatures. In addition to the city and highway cycles, the fuel economy adjustments take into account US06 (high speed), SC03 (with A/C) and Cold FTP (cold temperature operation) cycle data.

Starting with MY2008, all vehicles are required to report fuel economy estimates for consumer comparison using the new 2006 methodology. However, because testing all vehicles on all additional cycles was not considered practical, the EPA regulations allow an option of using a so-called "5-cycle formulae" based adjustment as listed below. The formulae were developed from the 5-cycle data that was available to EPA in 2005 and 2006. The data set was based on data from tests of 615 vehicles, including about 10 late model HEVs.

Equation 1:

$$\text{City MPG} = \frac{1}{\left(0.003259 + \frac{1.1805}{\text{FTP FE}}\right)}$$

Equation 2:

$$\text{Highway MPG} = \frac{1}{\left(0.001376 + \frac{1.3466}{\text{HFET FE}}\right)}$$

FTP FE – the fuel economy in miles per gallon of fuel during the FTP (or City) test cycle

HFET FE – the fuel economy in miles per gallon of fuel over the HFET (or Highway) test cycle

[4] EPA Fuel Economy data files can be downloaded from http://www.fueleconomy.gov/feg/download.shtml

[5] Federal Register, December 27, 2006, 40 CFR Parts 86 and 600 "Fuel Economy Labeling of Motor Vehicles: Revisions to Improve Calculation of Fuel Economy Estimates; Final Rule".

The EPA 5-cycle adjustments did impact the HEV fuel economy ratings more than the impact on conventional vehicles' fuel economy ratings because hybrids are typically more sensitive to auxiliary loads such as an air conditioning operation. Also, the HEV battery performance is significantly downgraded under low ambient temperatures and many current hybrid engine shut-off strategies cease to operate at extreme ambient temperatures. However, EPA's adjustment factors are based primarily on theoretical considerations of the effects of real world driving and little actual data for on-road fuel economy existed at the time the adjustment factors were developed to validate the EPA 5-cycle equations.

In order to validate the EPA 5-cycle adjustments for advanced technology vehicles, EEA examined fuel economy data from on-road testing. EEA found that the US DOE Idaho National Laboratory (INL) maintains well documented fuel economy test data for various electric vehicle technologies[6]. In the case of HEVs, the DOE also sponsors a fleet testing program called HEV America, which is designed to track and document various aspects of HEV operation, including fuel economy of vehicles in actual fleet use.

There are two types of plug-in hybrid vehicles – one that is similar to a HEV with a larger battery and the second that is similar to a battery electric vehicle with an on-board charger. We have used the PHEV nomenclature to refer to the first kind of plug-in vehicle while the second kind is referred to as an Extended Range Electric Vehicle (EREV).

For PHEVs, EEA found that INL has tested some PHEV models (PHEV America program) and detailed reports are available on the INL website. The PHEV America tests were performed using dynamometer tests over series of UDDS (Urban Dynamometer Driving Schedule) and HWFET (Highway Federal Emissions Test) cycles. The key challenge for PHEV analysis is the fact that overall fuel economy is dependent on the driving distance. It should be noted that in this context, there is no pure electric mode independent of driving cycle since the engine is turned on if power demand exceeds available battery power, independent of the state-of-charge of the battery. Confusingly, the ARB has not distinguished this type of PHEV and has derived EER numbers only for the EREV type of plug-in hybrid. For this analysis of PHEV EER, we evaluated fuel economy at a 32.7 mile driving distance. This distance is the average daily driving distance per vehicle as reported in the last DOT Household Travel Survey, 2001. As an additional data source for PHEVs, we found that Google has a well documented vehicle testing program designed to demonstrate real-world technology capabilities. The

[6] Idaho National Laboratory, Advanced Vehicle Testing Website http://avt.inl.gov/

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program is called Recharge IT[7] and it was launched in summer 2007. Google's program involves driving PHEV models through 257 trips, covering a total distance of 2,228 miles. Professional drivers were hired to test different types of vehicles in order to reduce test-to-test variation. Accessories were used during testing, including "moderate" use of air conditioning. However, the tests were conducted in the San Francisco Bay Area and could potentially under-represent air-conditioner use on a national basis.

For real world test data on Electric Vehicles, the US DOE has partnered with Southern California Edison (SCE) in a testing program, while INL's website also maintains detailed reports[8] of their own in-house testing. The test data on EVs are for older technology vehicles marketed by major OEMs in California during the late 1990s. The SCE test program was conducted on public use roads in Los Angeles and attempted to replicate actual city and highway driving conditions with and without the use of air-conditioning.

Data for the latest generation FCVs is more limited simply because there are few models available and they are special build vehicles. The Honda Clarity has been tested by the EPA for certification but no on-road data on fuel economy has been reported. Honda, in its submission to ARB on the LCFS, stated that it believed the EPA 5-cycle adjustment provided a reasonable estimate of the actual on-road fuel economy that Honda had observed for its own in-house FCV fleet. We also found some publicly available on road fuel economy data from Motor Trend Magazine's test of the GM Equinox FCV and Toyota's published estimate of on-road fuel economy for the Highlander FCV.

In order to properly compare various fuel economy estimates, it is also necessary to account for vehicle attribute differences. For example, most HEVs are equipped with continuously variable transmissions, whereas their conventional counterparts use regular automatic transmissions- a significant attribute difference affecting fuel economy. Also, EPS (Electric Power Steering), aerodynamic drag improvement devices and low rolling resistance tires are often adopted by more advanced technology vehicles.

The adjustment for differences in attributes is based on a multiplicative fuel consumption reduction approach used by the National Academy of Sciences in its 2002 report on CAFE. Essentially, if two technologies each reduce fuel consumption by 10%, the model assumes that the combined effects are 1-(0.9*0.9) or 19%, not 20%. Each successive technology has a smaller absolute impact since the base vehicle fuel consumption is lower. The technology differences considered do not have any significant

[7] Program description, vehicles tested and testing methodology is described on the RechargeIT website at http://www.google.org/recharge/

[8] Southern California Edison (SCE) Fleet and Pomona Loop Testing program, data available at http://avt.inl.gov/fsev.shtml

synergy or dis-synergy and the reductions are independent of each other. In each case, the adjustment was made to the comparable gasoline vehicle's fuel economy since the sensitivity of fuel economy to technology improvements are known for gasoline vehicles. The adjustments were made, where applicable, for the following technologies:

- Rolling resistance reduction by 15%, equivalent to a 2.2% fuel consumption improvement. Most advanced technology vehicles specify lower rolling resistance tires, and/or higher inflation pressures. Our contacts with manufacturers revealed that (except in the case of high performance vehicles) typical rolling resistance coefficient for HEV/BEV/FCV are in the 0.006 to 0.0065 range while typical values for a 2007/2008 model year conventional vehicle range from 0.0070 to 0.0075
- Electric Power Steering – 2% fuel consumption improvement. This feature is typically standard on hybrid and electric vehicles but is also now found on some conventional vehicles.
- Aerodynamic drag reduction by 10% (1.8% fuel consumption improvement). This improvement was used since many HEV/BEV models feature underbody covers and add-on aerodynamic aids. Typically, addition of an underbody cover reduces the drag coefficient by 0.02 while add-on devices reduce drag by 0.01. Given the average co-efficient for compact and mid-size cars is in 0.30 to 0.32 range, the 10% drag reduction appears appropriate where the vehicles share the same body or have similar levels of body aerodynamic drag coefficient.
- Transmission differences (for HEVs and PHEVs only). The adjustments were made according to a basic assumption that 4-speed vs. CVT results in fuel consumption difference of 5.7% (5-speed vs. CVT – 3.4%). No adjustments were made for transmissions with 6 speeds or higher since the difference relative to a CVT is very small.
- Rated power differences. A linear power / fuel economy relationship was assumed (for every 10% reduction of rated power, a 2.2% fuel consumption improvement is realized).

After the attribute adjustments were made, the EER determination was a straight forward exercise. The following sections document the data analysis for the four technologies considered.

Hybrid Electrical Vehicles (HEVs)

In order to verify the new EPA fuel economy adjustment procedure ability to estimate real world fuel economy performance, EEA compared the latest model year HEV fleet data (as tested by the HEVAmerica) against the Fuel Economy Guide data adjusted using the new EPA methodology for the same models and years. Table 1 lists the vehicle selection from the HEVAmerica program and fuel economy performance reported by the two sources. Note that the 2004 Prius data is also included since the model is by far the highest volume HEV in the US market and its design has not changed to 2007/2008.

Table 1. EPA Fuel Economy Guide Data Adjusted According to New Procedures versus INEL HEVAmerica Program Fleet Average Fuel Economy.

Vehicle	**INL Fleet Cumulative FE [mpg]**	**EPA Unadjusted Comb [mpg]**	**EPA New Adjusted Comb FE [mpg]**	**FE Diff. [%]**	
2008 Chevy Tahoe HEV	22.30	28.21	21.40	4.1	
2007 Toyota Camry HEV	33.70	45.94	33.72	-0.1	
2006 Honda Civic HEV	39.00	58.84	42.33	-8.5	
2004 Toyota Prius HEV	44.20	65.78	46.49	-5.2	
				-2.4	Average

The comparison indicates that the HEV America versus the EPA 5-cycle (or "EPA New") method fuel economy differences are below 10% in all cases. Furthermore, the fleet fuel economy performance is slightly lower (as reported by fleet operators) than the 5-cycle based estimate. The HEV America vehicles were tested in Arizona (i.e., an area with high A/C load conditions) so some fuel economy difference can be explained by the choice of location. Despite that, the fuel economy average difference is only about 2%. Based on the result of this analysis, EEA has used the EPA 5-cycle methodology to predict real world performance of hybrid vehicles in this study.

For MY2009, a wide selection of hybrid vehicles are available, ranging from full size trucks by GM to compact cars such as Toyota Prius and Honda Civic. Table 2 summarizes the 2009 HEVs in terms of their basic specifications[9]. Only full function HEVs are presented, as well as the IMA (Integrated Motor Alternator) hybrid Civic design by Honda. Table 2 also includes comparison of data for conventional gasoline versions of hybrid vehicles where available. Since the Toyota Prius HEV is a unique vehicle design, its specifications are compared against what we consider its closest conventional alternative (in terms of overall vehicle and power-train characteristics), the Toyota Corolla.

Table 2. MY2009 Fuel Economy and Attribute Data for HEVs and Conventional Gasoline Derivatives.

CAR LINE	DISPL	Total System Power [hp]	Other Attrib.	TRANS	DRIVE	Adjusted EPA New Comb [mpg]
C15 SILVERADO 2WD	6.2	403		Auto(L6)	R	14.75
C15 SILVERADO 2WD HYBRID	6	369	EPS, Aero	Auto(AV)	R	21.40
K15 SILVERADO 4WD	6.2	403		Auto(L6)	4	14.30
K15 SILVERADO 4WD HYBRID	6	369	EPS, Aero	Auto(AV)	4	21.40
C1500 TAHOE 2WD	6.2	395		Auto(L6)	R	14.60
C1500 TAHOE HYBRID 2WD	6	369	EPS, Aero	Auto(AV)	R	21.40
ESCAPE FWD	2.5	171	EPS	Auto(L6)	F	23.16
ESCAPE HYBRID FWD	2.5	177	EPS	Auto(AV)	F	32.43
ESCAPE 4WD	2.5	171	EPS	Auto(L6)	4	21.31

[9] Data is from the US EPA Fuel Economy Guide as well manufacturer websites and research engines such as www.cars.com.

ESCAPE HYBRID 4WD	2.5	177	EPS	Auto(AV)	4	27.73
C15 SIERRA 2WD	6.2	403		Auto(L6)	R	14.75
C15 SIERRA 2WD HYBRID	6	369	EPS, Aero	Auto(AV)	R	21.40
K15 SIERRA 4WD	6.2	403		Auto(L6)	4	14.30
K15 SIERRA 4WD HYBRID	6	369	EPS, Aero	Auto(AV)	4	21.40
C1500 YUKON 2WD	6.2	395		Auto(L6)	R	14.60
C1500 YUKON HYBRID 2WD	6	369	EPS, Aero	Auto(AV)	R	21.40
K1500 YUKON 4WD	6.2	395		Auto(L6)	4	14.30
K1500 YUKON HYBRID 4WD	6	369	EPS, Aero	Auto(AV)	4	21.40
CIVIC	1.8	140		Auto(L5)	F	28.28
CIVIC HYBRID	1.3	110	EPS	Auto(AV)	F	42.33
GS 450H	3.5	340	EPS	Auto(S6)	R	23.35
GS 350	3.5	303		Auto(S6)	R	21.55
LS 460 L AWD	4.6	380	EPS	Auto(S8)	4	18.29
LS 600H L	5	438	EPS	Auto(S8)	4	20.54
TRIBUTE FWD	2.5	171	EPS	Auto(L6)	F	23.16

TRIBUTE HYBRID 2WD	2.5	177	EPS	Auto(AV)	F	32.43
TRIBUTE 4WD	2.5	171	EPS	Auto(L6)	4	21.31
TRIBUTE HYBRID 4WD	2.5	177	EPS	Auto(AV)	4	27.73
MARINER FWD	2.5	171	EPS	Auto(L6)	F	23.16
MARINER HYBRID FWD	2.5	177	EPS	Auto(AV)	F	32.43
MARINER 4WD	2.5	171	EPS	Auto(L6)	4	21.31
MARINER HYBRID 4WD	2.5	177	EPS	Auto(AV)	4	27.73
ALTIMA	2.5	175		Auto(AV)	F	25.94
ALTIMA HYBRID	2.5	198	EPS	Auto(AV)	F	34.14
COROLLA	1.8	132	EPS	Auto(L4)	F	30.07
PRIUS	1.5	110	EPS, Aero	Auto(AV)	F	46.49
CAMRY	2.4	158		Auto(L5)	F	25.00
CAMRY HYBRID	2.4	187	EPS	Auto(AV)	F	33.72
HIGHLANDER 4WD	3.5	270	EPS	Auto(S5)	4	19.08
HIGHLANDER HYBRID 4WD	3.3	270	EPS	Auto(AV)	4	26.25

Table 3 documents fuel economy adjustment calculations for attribute differences between HEVs and corresponding conventional gasoline models.

Table 3. Fuel Economy (EPA New) Comparison, HEVs vs. Conventional Gasoline. Adjustment for Attribute Differences.

Full HEV Models				Adjustment for Attribute Differences – FC Improvement						
	HEV MPG	Gasoline Counterpart MPG	Fuel Cons. GPM	RR Red 15%	EPS	Drag Red 10%	Power Delta 10%	**Transm Delta**	**Adjusted Gasoline MPG**	FE Ratio
				2.2	2	2	2.2			
C15 SILVERADO 2WD HYBRID	21.40	14.75	0.0678	0.0663	0.0650	0.0637	0.0625	0.0625	16.00	1.34
K15 SILVERADO 4WD HYBRID	21.40	14.30	0.0700	0.0684	0.0670	0.0657	0.0645	0.0645	15.51	1.38
C1500 TAHOE HYBRID 2WD	21.40	14.60	0.0685	0.0670	0.0656	0.0643	0.0634	0.0634	15.78	1.36
ESCAPE HYBRID FWD	32.43	23.16	0.0432	0.0422	0.0422	0.0414	0.0417	0.0417	23.98	1.35
ESCAPE HYBRID 4WD	27.73	21.31	0.0469	0.0459	0.0459	0.0450	0.0453	0.0453	22.06	1.26
C1500 YUKON HYBRID 2WD	21.40	14.60	0.0685	0.0670	0.0656	0.0643	0.0634	0.0634	15.78	1.36
K1500 YUKON HYBRID 4WD	21.40	14.30	0.0700	0.0684	0.0670	0.0657	0.0648	0.0648	15.44	1.39
CIVIC HYBRID	42.33	28.28	0.0354	0.0346	0.0339	0.0332	0.0316	0.0306	32.72	1.29
GS 450H	23.35	21.55	0.0464	0.0464	0.0455	0.0455	0.0467	0.0467	21.42	1.09
LS 600H L	20.54	18.29	0.0547	0.0547	0.0547	0.0547	0.0565	0.0565	17.69	1.16
ALTIMA HYBRID	34.14	25.94	0.0386	0.0377	0.0369	0.0362	0.0373	0.0373	26.84	1.27
PRIUS	46.49	30.07	0.0333	0.0325	0.0325	0.0319	0.0307	0.0290	34.54	1.35
CAMRY HYBRID	33.72	25.00	0.0400	0.0391	0.0383	0.0376	0.0391	0.0378	26.49	1.27
HIGHLANDER HYBRID 4WD	26.25	19.08	0.0524	0.0512	0.0512	0.0502	0.0502	0.0485	20.61	1.27

The adjusted conventional gasoline fuel economy was compared to the corresponding HEV fuel economy to derive EER values (the last column of Table 3). Our analysis shows that EER ratios of HEVs versus their comparable conventional gasoline models vary but are clearly dependent on vehicle design strategy. The two high performance hybrid vehicles, the Lexus GS450h and LS600h, have a calculated EER of 1.09 and 1.16, respectively. All other hybrids ranging from the Toyota Prius to the GM Silverado have an average EER of 1.32 $\pm$ 0.06. Honda's Civic EER is also at 1.30, although this hybrid technology is very different from the technology employed in other hybrids. GM's hybrids are full size SUVs and trucks equipped with large 6L engines, and the EER values for GM's design averages 1.36, very similar to the overall average EER.

Plug-In Hybrid Electrical Vehicles (PHEVs)

Since OEM-level PHEV technology is not yet commercially available in the US, there is no certification test data for these vehicles. However, EEA found that government labs such as DOE's Idaho National Laboratory have tested PHEV models that are conversions of HEV models (in the PHEV America program) and detailed reports are available on the INL website.

EEA examined the baseline performance reports for Hymotion PHEV and Energy CS PHEV conversions, both of which are derived from the Toyota Prius, mainly by a battery replacement with higher capacity LiIon batteries. Table 4 summarizes the two PHEV conversions and their attributes, including the battery pack specifications. The original Toyota Prius HEV data is provided for reference purposes, while the Toyota Corolla is used as the conventional gasoline counterpart for the baseline.

The PHEV America tests were performed using dynamometer driving over series of UDDS (Urban Dynamometer Driving Schedule) and HWFET (Highway Fuel Economy Test) cycles. The key challenge for deriving an EER is the fact that overall fuel economy is dependent on the driving distance, as illustrated in Figure 1. While PHEVs are typically designed to effectively operate as an electrical vehicle for short distances and light loads, the battery pack is depleted over some distance (typically 20 to 40 miles) and the vehicle reverts back to a conventional HEV operation. In conventional HEV operation, these vehicles suffer a small penalty relative to the HEV model due to the extra weight of the battery pack. The dyno test data shows a fuel economy of 60 mpg on the UDDS for the PHEV as compared to 66.6 mpg for the normal Prius as certified by EPA, which indicates a 10% EER penalty. For this analysis we used a 32.7 mile driving distance to estimate PHEV fuel economy. 32.7 miles is the average daily vehicle miles of travel [10] An assumption is made that PHEVs are charged overnight and no charging is done between trips during the day.

Because PHEV America test procedures involve dynamometer tests, for comparison purposes, we used EPA Fuel Economy guide unadjusted values for conventional Prius and Toyota Corolla. The EPA 5-cycle adjusted fuel economy values for PHEVs and conventional vehicles were calculated, and the resulting fuel economy values are listed in the last column of Table 4.

[10] The US Department of Energy, Transportation Energy Data Book: Edition 27, 2008, Table 8.11.

Table 4. The PHEV America Vehicle Test Results Compared to Conventional Models.

Year	Model	Engine & Trans.	Total System Power [hp]	Electric Componentry	Combined FE as Tested [mpg]*	EPA 5-cycle Adjusted FE [mpg]
2007	Toyota Prius Hymotion PHEV Conversion	1.5L ECVT	110	184.8V 4.7kW-hr LiIon battery, 2.69kW-hr usable energy	109.13	71.10
2006	Toyota Prius Energy CS PHEV Conversion	1.5L ECVT	110	230.4V 10kW-hr LiIon battery, 4.88kW-hr usable energy	117.67	76.05
2006	Toyota Prius (EPA Tested)	1.5L ECVT	110		65.78	46.49
2007	Toyota Corolla (EPA tested)	1.8L 4AT	126		39.11	29.31

*Tested fuel economy for PHEVs was derived from reported data by DOE PHEVAmerica program. The city and highway results were interpolated for 32.7-mile driving distance from data similar to the chart below.

Figure 1. Hymotion PHEV Fuel Economy Test Results as a Function of Cumulative Distance. (Urban Driving Dynamometer Cycle)

Note that the Blue solid line indicates the cumulative fuel economy, which approaches the regular HEV fuel economy performance (green bars) as the cumulative driving distance increases and the battery original charge is depleted after 35 miles.

As an additional data source for PHEVs (and as a reference for HEVs), we found that Google has a well documented vehicle testing program designed to demonstrate the real-world technology capabilities. The program is called RechargeIT[11] and was launched in summer 2007 with various advanced technology and conventional vehicles. Driving statistics have been collected for over a year now. Table 5 summarizes vehicle specifications and test results for this program.

EEA calculated the equivalent combined fuel economy for Google's PHEVs using their reported "Mixed City/Hwy" results for gasoline fuel economy, plus reported electricity consumption converted to gasoline equivalent using the following conversion factors: 1kW-hr electricity = 3,412Btus; 1gal of regular gasoline=115,400Btus. The conversion factors are from ORNL, Transportation Energy Data Book: Edition 27, 2008, Tables B.4 and B.6.

Table 5. Google's Recharge IT Project: Vehicle Specifications and Fuel Economy Test Results.

Year	Model	Engine & Trans.	Total System Power [hp]	Electric Componentry	Total Combined FE as Tested [mpg]
2007	Toyota Prius Hymotion PHEV Conversion	1.5L ECVT	110	184.8V 4.7kW-hr LiIon battery, 2.69kW-hr usable energy	71.8
2007	Toyota Prius	1.5L ECVT	110	Original	46.4
2007	Toyota Corolla	1.8L 4AT	126		31.4
2007	Ford Escape PHEV Hymotion Conv.	2.3L ECVT	155	70kW motor, 8kW-hr LiIon battery	43.2
2007	Ford Escape HEV	2.3L ECVT	155	Original	31.6
2007	*Ford Escape***	*2.3L 4AT*	*153*		*21.4***

[11] Program description, vehicles tested and testing methodology is described on the RechargeIT website at http://www.google.org/recharge/

**Google did not test a conventional Ford Escape. This data is based on EPA 2007 Fuel Economy guide unadjusted combined fuel economy adjusted per EPA's 5-cycle procedures.

Note that the Toyota Prius Hymotion conversion PHEV fuel economy results from Google are virtually identical to the EPA 5-cycle adjusted fuel economy shown in Table 4, giving credence to Honda's suggestion that the 5-cycle adjustment factors are applicable to all vehicle types. Also, the Prius HEV results from Google's on-road tests are also very close to the 5-cycle adjusted estimate, differing by only 0.1mpg.

The fuel economy results from PHEVAmerica and Google programs were further used to adjust the conventional gasoline fuel economy for attribute differences. Table 6 summarizes the results. The EER values for PHEVs are fairly close even though it was calculated using different data sources, ranging from 1.86 for the Escape PHEV, to 2.31 for the Prius conversion. The Hymotion PHEV results are very close as tested by the two completely independent entities. Clearly, the results would be different if the driving distance assumptions for PHEVs would be more than 32.7 miles. The average EER is 2.12 for the 4 models listed below. When the batteries are depleted and PHEVs run in charge sustaining mode, it would be logical to expect some reduction in fuel economy relative to an HEV due to the weight of the battery pack and the limited evidence suggests a 10% EER penalty.

Table 6. PHEV and Conventional Gasoline Model Comparison. Attribute Difference

	PHEV Models				**Adjustment for Attribute Differences**					
Source		**MPG**	**Gas. Eq. MPG**	**GPM**	**RR Red 15%**	**Transm**	**Drag Red 10%**	**Power Delta 10%**	**Adj Gas MPG**	**FE Ratio**
					2.2	4.3	2	2.2		
DOE	**Toyota Prius Hymotion PHEV Conversion**	71.10	29.31	0.0341	0.0334	0.0319	0.0313	0.0304	32.87	2.16
DOE	**Toyota Prius Energy CS PHEV Conversion**	76.05	29.31	0.0341	0.0334	0.0319	0.0313	0.0304	32.87	2.31
Google	**Toyota Prius PHEV Hymotion Conversion**	71.75	29.31	0.0341	0.0334	0.0319	0.0313	0.0304	32.87	2.18
Google	**Ford Escape PHEV Hymotion Conversion**	43.18	21.39	0.0468	0.0457	0.0438	0.0429	0.0430	23.25	1.86

In this context, the Chevy Volt extended range electric vehicle (EREV) is difficult to evaluate. The Volt uses no gasoline over the first 40 miles and operates as a pure BEV. If most PHEV buyers use these vehicles for typical urban/suburban driving, then the Volt would rarely use the gasoline engine and act primarily as a BEV. The EREV data is considered along with battery electric vehicles in the next section.

Battery Electric Vehicles

At present, Tesla is the only manufacturer that markets a full function EV – the Tesla Roadster, but the vehicle is a low volume sports car sold as an ultra-performance luxury vehicle, which is not representative for purposes of this study. Other OEMs such as BMW (Mini Cooper EV), Mitsubishi and Nissan have revealed their new EV designs, but fuel economy data is not yet available from actual on-road tests.

The US DOE and Southern California Edison (SCE) published older model EV performance reports, including data from public road testing, and the data is available at the INL website[12]. Figure 2 provides a sample test sheet for 1999 Dodge Epic EV as released by SCE. Note that energy consumption is reported on AC kW-hr/mi at the plug for four urban and four freeway test conditions. The energy consumption was metered "at the plug" as the vehicle battery was charged.

EEA selected only those EVs that are equipped with relatively new battery technology, namely Nickel-Metal Hydride (NiMH) and Lithium Ion (LiIon) and omitted data for Lead Acid battery-equipped vehicles. Table 6 list the vehicle selected and the EV specifications. The gasoline-equivalent fuel economy was calculated using the following steps for urban and highway driving cycle data:

1. Calculation of average energy consumption in AC kW-hrs/mile for the 4 urban (UR1 through UR4) and four freeway (FW1 through FW4) driving cycles as an average on-road fuel economy for urban and highway driving

2. Conversion to gasoline-equivalent fuel economy: 1kW-hr electricity = 3,412Btus; 1gal of regular gasoline=115,400Btus. The conversion factors are from ORNL, Transportation Energy Data Book: Edition 27, 2008, Tables B.4 and B.6.

3. Calculation of "combined" equivalent fuel economy using EPA procedures (55/45 city/hwy weighting).

EEA used EPA fuel economy guide data for equivalent conventional gasoline models, for the same model years, to obtain unadjusted laboratory test results for conventional vehicles. The EPA 5-cycle fuel economy adjustment procedures were used to derive adjusted combined mpg values for conventional gasoline vehicles. Table 7 shows the results of the analysis, as well as the vehicle specifications, compared against the EV equivalent fuel economy and specifications. EEA adjusted the conventional gasoline vehicle fuel economy values for attribute differences relative to their EV counterparts. It should be noted that all EVs were specified with rated power significantly lower than their conventional counterparts but offer higher torque at low speeds. In order to compensate or the torque benefits, previous analyses of EV performance have shown that equivalent low and mid-speed performance is obtained with an electric motor with about 25% lower horsepower than a conventional gasoline engine. Hence, the performance corrections were applied after correcting electric motor power by this factor.

Table 7. EV Models, their Specifications and Equivalent Fuel Economy Compared to Conventional Gasoline Models.

Year	Model	Eng	Rated Power [hp]	Electric Component Specifications	Curb Weight [lb]	Combined FE [mpg] (55/45)	EPA 5cycle Comb FE
1999	Dodge Epic (Caravan) EV		100	336V 82A-hr NiMH battery	4878	48.87	
	Dodge Caravan	2.4L I4	150		3533		19.93
1998	Ford Ranger EV		90	300V 95A-hr NiMH battery	4100	75.42	
	Ford Ranger XL	2.5L I4	119		3086		19.66
	Chevy S-10 EV		114	343V 85A-hr NiMH battery	4200	42.96	
	Chevy S-10	4.3L	175		3029		16.82
1999	Toyota RAV4 EV		67	288V 95A-hr NiMH battery	3500	87.08	
	Toyota RAV4	2L I4	127		2668		23.15
1999	Honda EV Plus		66	288V NiMH battery	3594	70.46	
	Honda Civic Hatchback	1.6L I4	106		2359		26.85
1999	Nissan Altra EV		83	345V 95A-hr LiIon battery	3940	100.55	
	Nissan Altima Sedan	2.4L I4	150		3012		22.53

[12] Southern California Edison (SCE) Fleet and Pomona Loop Testing program, data available at http://avt.inl.gov/fsev.shtml

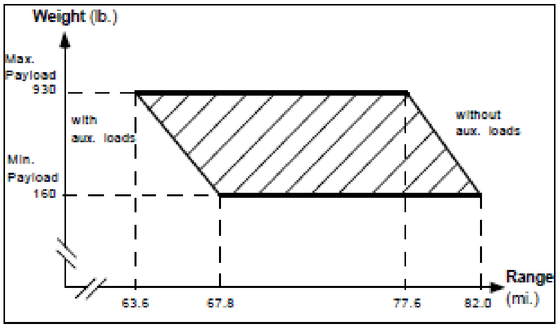
1999 Chrysler Epic (NiMH Batteries) Performance Characterization Summary

Electric Transportation Division

Southern California Edison
An Edison International Company

Urban Range

(On Urban Pomona Loop – see other side for map)

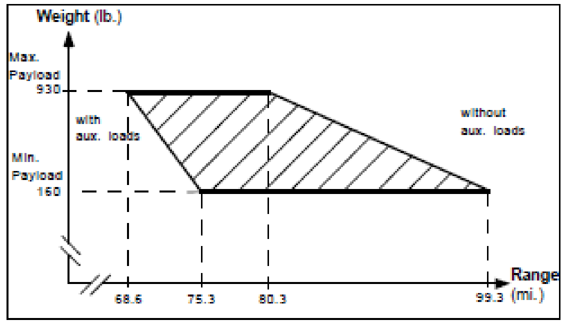


Test	UR1	UR2	UR3	UR4
Payload (lb.)	160	160	930	930
AC kWh Recharge	53.91	50.03	53.02	52.61
AC kWh/mi.	0.663	0.734	06.75	0.823
Range (mi.)	82.0	67.8	77.6	63.6
Avg. Ambient Temp.	75° F	80° F	79° F	85° F

UR1	Urban Range Test, Min Payload, No Auxiliary Loads
UR2	Urban Range Test, Min Payload, A/C on High, Headlights on Low, Radio On
UR3	Urban Range Test, Max Payload, No Auxiliary Loads
UR4	Urban Range Test, Max Payload, A/C on High, Headlights on Low, Radio On

Freeway Range

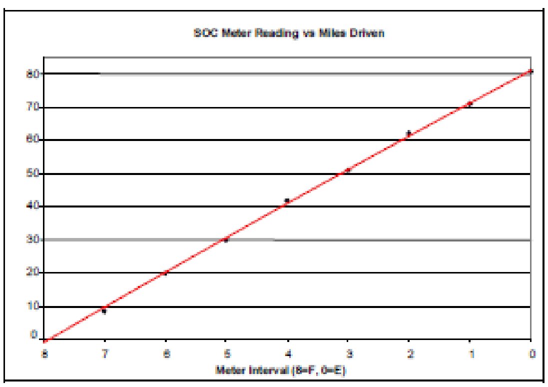
(On Freeway Pomona Loop – see other side for map)



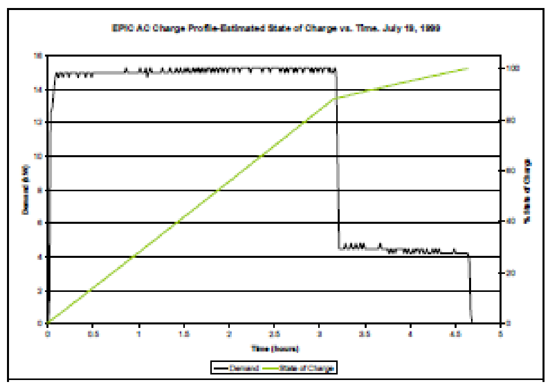
Test	FW1	FW2	FW3	FW4
Payload (lb.)	160	160	930	930
AC kWh Recharge	54.08	51.54	50.42	55.52
AC kWh/mi.	0.542	0.674	0.598	0.799
Range (mi.)	99.3	75.3	80.3	68.6
Avg. Ambient Temp.	86° F	88° F	83° F	101° F

FW1	Freeway Range Test, Min Payload, No Auxiliary Loads
FW2	Freeway Range Test, Min Payload, A/C on High, Headlights on Low, Radio On
FW3	Freeway Range Test, Max Payload, No Auxiliary Loads
FW4	Freeway Range Test, Max Payload, A/C on High, Headlights on Low, Radio On

State of Charge Meter (UR1)



Charger



MEASURED VALUE AT PEAK AC POWER*	
Voltage	204.9V
Current	77.5 A
Real Power	15.22 kW
Reactive Power	771 VAR
Apparent Power	15.87 kVA
Total Power Factor	0.96 PF
Displacement Power Factor	1.00 dPF
Voltage THD	2.2%
Current THD	28.2%
Current TDD	27.1%

*Total/average on a three phase grid connection.

Test Date: August 1999

Figure 2. Sample test report sheet for 1999 Chrysler Epic EV as tested by SCE.

The results of power and attribute adjustments are listed in Table 8. The EER values for different EVs are highly variable and no obvious reason is apparent for the large difference. Three vehicles – the

Dodge, Honda and Chevy models – have EER values of 2.2 ± 0.1, while the Ford, Toyota and Nissan models are at 3.4 ± 0.4. In particular, results from the Nissan Altra EV are suspect since it is significantly larger then the other EVs, and heavier than the RAV-4 but reports significantly higher fuel economy than all other EVs for which we have data. The technology differences, however, or even base vehicle capabilities, cannot account for the difference. For example, the Ford Ranger truck and the Chevy S-10 truck had similar weights, payload and power, but the Ford EV has a gasoline equivalent rating of 73.5 mpg while the S-10 EV has a rating of less than 42 mpg! The average EER for all EVs in this study is 2.83 while the optimistic EER for the 'best' EVs is 3.4

Table 8. Fuel Economy Adjustment for Attribute Differences and Resulting FE Ratios.

EV Models				Adjustment for Attribute Differences					
	MPG	**Gas Eq. MPG**	**GPM**	**RR Red 15%**	**EPS**	**Drag Red 10%**	**Power Delta 10%**	**Adj Gas MPG**	**FE Ratio**
				2.2	2	2	2.2		
Dodge Epic (Caravan) EV	48.87	19.93	0.0502	0.0491	0.0481	0.0471	0.0445	22.45	2.18
Ford Ranger EV	75.42	19.66	0.0509	0.0497	0.0487	0.0478	0.0470	21.27	3.55
Chevy S-10 EV	42.96	16.82	0.0594	0.0581	0.0570	0.0558	0.0523	19.11	2.25
Toyota RAV4 EV	87.08	23.15	0.0432	0.0422	0.0414	0.0406	0.0348	28.73	3.03
Honda EV Plus	70.46	26.85	0.0372	0.0364	0.0357	0.0350	0.0322	31.02	2.27
Nissan Altra EV	100.55	22.53	0.0444	0.0434	0.0425	0.0417	0.0366	27.34	3.68
								Average	2.83

In this context, the GM Volt has a claimed maximum electric range of 40 miles, and it utilizes a 16kW-hr battery. Assuming the range is associated with discharging the battery to 10% state-of-charge, the electricity consumption from the battery is 0.36 kW-hr/mi, or 0.42 kW-hr/mi at the plug with a charger of 85% efficiency. This is equivalent to 79.85 mpg, quite similar to the RAV-4 EV electricity consumption. However, this is very different from the ARB estimate of 138 mpg, which we believe may be a battery-to-wheels energy consumption on the dyno, not a plug to wheels energy consumption in the real world. Hence, the BEV factors appear to be applicable the EREV when operating as an EV, but the ARB factor for the EER of a battery electric vehicle is much too high..

As an additional issue with the EREV, the Chevy Volt has been assigned an EPA 5 –cycle adjusted rating of 39.1 mpg, but this value is compared to the EPA 5-cycle rating for a Malibu of 23.1 mpg. The Malibu is a larger and more powerful car then the Volt and the Chevy Cobalt with a 2.2L is a much closer comparison in terms of size, although the Cobalt has better performance at higher speeds. The Cobalt has new EPA rating of 27 mpg, making the EER unadjusted for attribute differences to be 39.1/27 or 1.44. Adjusting for electric power steering, aero drag, tire rolling resistance and an assumed 10% power loss (detailed power data on the Volt are not publicly available), the attribute adjusted Cobalt will have an EPA new fuel economy of 29.9 mpg. The Volt's EER is then 39.1/29.9 or 1.31, virtually identical to the 1.32 average for all hybrid electric vehicles computed in section above. We recognize that the computations are approximate for the Volt since interior dimensions and performance data for the vehicle have not been publicly released by GM. Nevertheless, the agreement between the estimated data and the EER's computed previously suggest that the assumptions are quite reasonable.

Fuel Cell Vehicles (FCV)

Information available to EEA suggests that virtually all the largest OEMs still maintain active Fuel Cell Vehicle (FCV) development programs. However, only one vehicle, the Honda FCX Clarity, is available for lease beyond strictly controlled demonstration programs. The Clarity was tested by the US EPA for certification and we did obtain the fuel economy testing data for the vehicle. EEA has also found some usable data for GM's Chevy Equinox FCV and Toyota FCV-adv, both of which are equipped with the latest generation fuel cell stacks, according to the OEMs. The following are data sources for the three FCVs:

- Honda FCX Clarity - Honda, "LCFS Draft Report and California GREET Analysis Comments" presentation submitted to CARB November 7, 2008. The presentation includes EPA unadjusted lab results. EEA converted the unadjusted fuel economy to "on-road" values using EPA 5-cycle adjustments.
- Chevy Equinox FCV - Motor Trend Magazine, December 2008. A reporter article about a private drive test (mixed city/hwy driving). Reported fuel consumption was 38.1mi/kg of H_2. As another data point for this vehicle we also used information compiled at www.evworld.com. This source provides the fuel economy estimate for the Equinox FCV at 45 mpg, for both city and highway. We used an average fuel economy value of the two sources for our analysis purposes.
- Toyota FCHV-adv -Toyota, "Progress and Challenges for Toyota's Fuel Cell Vehicle Development", Presentation at European Fuel Cell and Hydrogen Week, October 14, 2008. Reports "actual fuel economy" using Toyota's internal driving cycle to simulate real world

conditions in Japan. EEA used the reported figure of 23.75km/liter to obtain the "equivalent" combined fuel economy in mpg.

Table 8 summarizes specifications and data derived for the three FCVs as well as their gasoline counterparts. While the Equinox and the FCHV-adv are based on the conventional Equinox and Highlander, respectively, Honda's FCX Clarity is a unique design but we found it to be comparable to the Honda Accord 2.4L (interior volume is virtually identical for the two vehicles).

As with previous technologies, it was necessary to adjust the fuel economy for attribute differences. The adjustments are documented in Table 10. The power adjustment was made only for gasoline engine power exceeding 25% more than electric motor power. EEA analysis shows that EERs for the three FCVs average 2.22. However, the Equinox FCV EER is somewhat lower and the comparison is based on estimates from tests where the procedures are not well controlled. If this vehicle is excluded, the EER for the Honda and Toyota vehicles average to 2.3.

In this context, available data shows IC engine based hydrogen vehicles to have significantly lower efficiency than modern fuel cell vehicles, but they also appear quite unlikely to be marketed, so no detailed analysis of this option was performed. Ford and BMW are the two manufacturers who have researched this option and have shown several vehicles with a hydrogen fueled ICE engine. BMW's latest 7-series model has a claimed range of 200km (125 miles) with an 8 kg Hydrogen tank, suggesting a fuel economy of only 16 mpg, almost identical to the 15 mpg EPA rating for the gasoline counterpart. Ford's F-150 truck tested by INEL achieve an on-road rating of 16.8 mpg without air-conditioning and 15.4 mpg with air-conditioning, very similar to the 16 mpg EPA rating of the gasoline model. In both cases, there was a substantial loss of power output with hydrogen, on the order of 35%. Hence, these engines do not even offer an EER of 1 on a comparable attribute basis, and should not be grouped with FCV models.

Table 9. Fuel Cell Electrical Vehicle Major Specifications and Fuel Economy Compared Against Conventional Gasoline Vehicles.

Year	Model	Engine	Rated Power [hp]	Technology	Electric Components	EPA 5cycle
2008	Honda FCX Clarity		134	EPS, ETC	100kW FC stack, 288V LiIon battery	59.9
	Honda Accord EX	2.4L I4	190	4V DOHC iVTEC		24.3
2008	GM Equinox FCV		124		93 kW stack, 35kW 300V NiMH Battery	38.8

	GM Equinox FCV		124		93 kw stack, 35kW 300V NiMH Battery	45.0
	Chevy Equinox LT	3.4L V6	185	2V OHV, FWD		19.3
2008	Toyota FCHV-adv		121	FWD, 70MPa 156L H2 tank	90kW stack, 21kW NiMH battery	56.0
2007	Toyota Highlander	2.4L I4	155	FWD, VVT		21.7

Notes: Fuel economy for all conventional vehicles is EPA's New Combined. The 2008 Toyota FCHV-adv is compared against 2007 Highlander because 2008 model features a larger 3.5L V6 engine as standard.

Table 10. FCEV and Adjusted Conventional Gasoline Fuel Economy Comparison.

EV Models				Adjustment for Attribute Differences					
	FCV MPG	**Gas MPG**	**GPM**	**RR Red 15%**	**EPS**	**Drag Red 10%**	**Power Delta 10%**	**Adj. Gas MPG**	**FE Ratio**
				2.2	2	2	2.2		
Honda FCX Clarity	59.89	24.31	0.0411	0.0402	0.0394	0.0386	0.0372	26.87	2.23
GM Equinox FCV	41.89	19.26	0.0519	0.0508	0.0498	0.0498	0.0471	21.22	1.97
Toyota FCHV-adv	56.00	21.70	0.0461	0.0451	0.0442	0.0442	0.0439	22.79	2.46
								Average	2.22

Note: GM Equinox FCV fuel economy is averaged from two sources listed in Table 9. Drag reduction adjustment was made only for the Honda FCX Clarity since its exterior shape is more aerodynamic compared to the Accord, whereas other models are largely based on the conventional bodies.

Summary and Conclusions for Light-Duty Vehicles

The EEA analysis of the EER values for several alternative vehicle fuel types leads us to recommend the following EER values

- Gasoline Hybrid Vehicles: 1.32
- Plug-in Hybrid Vehicles: 2.1 (Charge depleting mode), 1.2 (Charge sustaining mode)
- Battery Electric Vehicles: 3.4

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- Extended Range Electric Vehicles : 3.4 (pure electric mode), 1.32 (Range extender mode)
- Fuel cell Vehicles: 2.3

In the case of the Battery Electric Vehicle, we have selected the average of the three highest EER vehicles to reflect the possibility that these vehicles had unspecified technology improvements that will be incorporated into future BEV models.

HEAVY DUTY VEHICLES

As noted in the methodology section, we have largely relied on the NREL evaluations of CNG and LNG buses and trucks, and hybrid buses to develop EER values for these vehicles. Most of these evaluations were done in the 2002 to 2007 time frame, and often compared these alternative fuel buses against diesel buses of comparable model years retrofitted with a particulate filter. However, none of these vehicles meet the 2010 emission standards so that future comparisons may not provide the same EER result. In addition, many of the natural gas engines used in the test vehicles such as the DDC Series 50 NG or Caterpillar NG engines are no longer in production and to the extent that these results are engine strategy specific, further uncertainty in the EER is introduced.

Both New York City Transit and NREL have conducted detailed and comprehensive evaluations of CNG buses against comparable diesel buses equipped with PM filters, with the buses run on the same routes with similar average speeds. The NYC Transit study[13] examined a fleet of about 200 Low floor Orion CNG buses from model year 2000 against a fleet of several hundred diesel buses form the 1995 to 1999 model years retrofitted with a PM filter. The diesel buses were found to have an average fuel economy of 2.6 mpg while the CNG buses were found to have a fuel efficiency of 0.81 therms per mile, which is only 1.61 mpg diesel equivalent using the standard diesel heating value of 130,500 Btu per gallon. This implies an EER of only 0.62.

More recent data from NREL evaluation of the NYC fleet of model year 2002 CNG buses with the DDC Series 50G engine compare to model year 1999 diesel buses produced similar results, with the CNG buses rated at 1.70 mpg and the diesel buses rated at 2.33 mpg, providing an EER of 0.73. Hence, older model stoichiometric CNG engines have much lower EER values relative to diesel engines. Newer “lean burn” engines have claimed fuel efficiencies comparable to diesel engine with EER ratios of about 1 but meeting the 2010 emissions standard will likely require that CNG engines

[13] Dana Lowell, William Parsley and Douglas Zupo, ‘Comparison of Clean Diesel Buses to CNG Buses’ new York city Transit Publication Undated published around 2005.

use three way catalysts and operate at stoichiometric fuel air ratios; hence, the 0.7 EER appears to be more correct for the future.

Hybrid vehicles of both the series and parallel type have been evaluated. Series hybrid buses from BAE Orion have been used by New York City Transit and NREL has completed a detailed evaluation of several design generations of these models.[14] Ten first generation hybrids were evaluated from October 2004 to September 2005 and ten second generation hybrids from February 2006 to January 2007. The second generation hybrid buses had somewhat lower actual fuel economy of 3.00 mpg while the first generation hybrids attained 3.19 mpg, largely because the second generation systems had EGR for lower emissions. The diesel bus fleet was rated at 2.33 mpg indicating an EER of 1.29 for the second generation fleet.

Analysis of parallel hybrid buses with the drivetrain using the GM Allison system and Caterpillar C9 engines was done by NREL at the King County Metro Transit Fleet.[15] That evaluation showed the diesel buses at 2.50 mpg and the hybrid buses at 3.19 mpg indicating an EER of 1.27, virtually identical to the finding in New York City in spite of significant design differences. Speeds in King County were higher than in New York (approximately 12 mph vs. 6mph) and hybrid bus fuel efficiency is sensitive to the drive cycle so that the comparison is not exact. However, there appears to be reasonable case for setting the hybrid bus EER at 1.3.

For Fuel cell buses powered by hydrogen, there are a few individual bus examples operating in several transit fleets. The buses are unique builds and DOE presented some preliminary data[16] from buses operating in AC Transit in Oakland (CA) and Connecticut Transit in Hartford. The EER data presented were 1.7 for AC Transit and 1.5 for CT Transit, but the slide suggested that the EER was highly dependent on duty cycle and hybridization of the system. An EER of 1.6 is recommended for this system based on an average of the limited available data.

In conclusion, the following EERs are recommended for heavy duty vehicles in urban operation;

- CNG vehicles: 0.7
- Hybrid vehicles: 1.3
- Fuel cell vehicles: 1.6

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[14] R. Barnitt, BAE/Orion Hybrid Electric Buses at NYC Transit, NREL technical report 540-42217, March 2008

[15] K. Chandler, K. Walkowicz, King County Metro Transit Hybrid Articulated Buses, NREL Technical Report 540-40585, December 2006

[16] DOE's Hydrogen Fuel Cell Activities, presented by K. Wipke , et al. at the Alternative Fuels & Vehicles Conference, Las Vegas, NV, May 12 2008