

**State of California  
Air Resources Board  
Expert Working Group  
Low Carbon Fuel Standard – Indirect Effects**

**Subgroup on Indirect Effects of Other Fuels**

**CARB EWG Members:**

**Phil Heirigs  
Jesper Kløverpris  
Robert Larson  
Seth Meyer  
Blake Simmons  
Wally Tyner  
Paul Wuebben**

**External Technical Experts:**

**Brooke Coleman  
Bjorn Pieprzyk**

## Executive Summary

### Immediate Term EWG-IE Recommendations to ARB:

- ARB should conduct an analysis, including but not limited to economic modeling, of the marginal barrel of oil. The magnitude of the change and the timeframe under consideration should be consistent with that used for other fuels.

### Short-Term EWG-IE Recommendations to ARB:

- ARB should conduct an analysis, including but not limited to economic modeling, of the marginal supply of natural gas, including but not limited to the GHG emissions from newly developed extraction techniques (e.g., hydraulic fracturing). The magnitude of the change and the timeframe under consideration should be consistent with that used for other fuels.
- ARB should conduct an analysis, including but not limited to economic modeling, of the potential market-mediated effect on electric power markets of using increased quantities of natural gas in the transportation sector. The magnitude of the change and the timeframe under consideration should be consistent with that used for other fuels.
- ARB should conduct a reevaluation of marginal electricity, stemming from the work conducted by McCarthy et al. The magnitude of the change and the timeframe under consideration should be consistent with that used for other fuels.
- ARB should conduct an analysis, including but not limited to economic modeling, of the impact of petroleum substitutes on refinery operations. The analysis should include, but not be limited to, the impact on major refining inputs and co-products.

### Long-Term EWG-IE Recommendations to ARB:

- Conduct an analysis of the substitution of fossil fuels with biofuels. The analysis should include all the factors influencing the substitution process in the short-medium and long term (e.g. market power of the OPEC Cartel, correlation between production costs and carbon intensity, predictions of conventional and unconventional fuels)
- ARB should initiate a preliminary scoping analysis of the potential direct and indirect effects of upstream heavy metal mining and processing. If potentially significant effects are identified, ARB should conduct an analysis of these effects, prioritizing the effects identified in the scoping analysis.

## 1.0 Background

The California Low Carbon Fuel Standard (LCFS) was approved by the California Air Resources Board (CARB) in April 2009. The LCFS Lookup Table includes carbon intensity (CI) values for both petroleum and alternative fuels. CI values are allocated to different fuels in two categories: direct emissions and land use and other indirect effects. The only indirect effect currently accounted and allocated under the LCFS is for indirect land use change (ILUC) against biofuels. In the initial LCFS analysis it was stated that no other significant indirect effects were identified for other fuels at that time, but that this issue would be re-examined over time. This position by the LCFS has attracted significant attention, both positive and negative, and it has been postulated by many that indirect effects of fuels exist for every fuel type by the very nature of their production, distribution, consumption, and interaction within the energy markets. In light of this and other uncertainties, CARB Board Resolution 09-31 directed CARB staff to convene an LCFS EWG comprised of recognized experts in the field of carbon LCA. Once constructed, the EWG identified the “indirect effects of other fuels” as a primary topic of inquiry and appointed a sub-group (EWG-IE) to investigate the issue. One of the primary tasks of this sub-group was to provide an overview of potential significant indirect effects of other fuels. This report contains the major recommendations of the EWG-IE.

In terms of the overall approach to resolving the complex issues associated with establishing metrics around the indirect effects of other fuels, the membership of the subgroup would like to identify the following as issues of general agreement:

- The LCFS should carbon score fuels symmetrically in terms of their evaluation of direct and indirect effects, thereby creating a level playing field for all fuel types
- The LCFS should use average and marginal data across different fuel pathways in a consistent manner, and when data and models are not available to do so they should fund research activities to address the gaps
- It is recognized that there may be data gaps in the attribution of indirect effects of fuels that should be addressed by ARB
- ARB or related entity should support an analytical effort, including but not limited to economic modeling, to try to estimate what petroleum fuel is on the “resource margin” in different reasonable scenarios (e.g. reference, high oil price, low oil price)
- ARB or related entity should support an analytical effort, including but not limited to economic modeling, to determine if increased biofuel production has a significant impact on marginal refining of fossil fuels in different reasonable scenarios (e.g. reference, high oil price, low oil price)
- ARB or related entity should support an analytical effort, including but not limited to economic modeling, to determine the type of electricity generation that is on the “resource margin” in targeted scenarios (e.g. reference, high oil price, low oil price) and as a function of the major fuel types that would rely on

electricity or otherwise influence power markets (electric drive, hydrogen and natural gas)

**A Note on Perspectives:**

**It should be noted that there were a number of issues discussed by the EWG-IE subgroup members for which consensus was not reached. As a result, this paper includes multiple perspectives on several issues as requested by ARB staff. Included in some perspectives are essentially rebuttals to the other perspective. The reader must recognize that the absence of a rebuttal in a particular perspective does not signal agreement with the other and should not discount the issues made in the various perspectives. As ARB works through these issues, we are hopeful that they will continue to seek guidance and input from EWG-IE members to expand on particular points (and counter-points), as there were numerous opinions offered during many discussions that could not be fully captured in this paper. In addition, any analyses of these issues that ARB conducts or initiates should include significant input from the industries affected to ensure that the data, models, and methods reflect the best knowledge available specific to the issue being investigated.**

## **2.0 Establishing System Boundary Conditions for Indirect Effects**

The EWG-IE made the initial determination that the terms “direct” and “indirect” effects must be clearly defined before any assessments can be made about the indirect effects of other fuels. The EWG-IE informally agreed to a set of definitions and presented them to the full EWG on July 15, 2010:

1. Direct effects: All significant effects within the primary production chain or life cycle (cradle to grave).
2. Co-product effects: Significant effects caused by co-products from the production chain (handled by the system expansion – or displacement – methodology)
3. Other market-mediated effects: Significant effects caused by changes in economic markets, e.g. ILUC or changes affecting marginal electricity or fossil fuel supply. This also includes ‘carbon leakage’ as a function of increased production/consumption.

The rationale behind these definitions is: (1) direct carbon effects are supply chain emissions – those emitted during production and use of the fuel; (2) co-product effects stem directly from the supply-chain of a respective fuel (e.g. petroleum coke, distiller grains), and should be treated separately given their causal proximity and carbon relevance with regard to producing the fuel; and, (3) other market-mediated effects are the less proximate indirect effects of producing and using a fuel, including but not limited to carbon emissions generally referred to as market-mediated effects, indirect effects or leakage.

It is recognized that the definitions established for direct, co-product and indirect effects overlie other practices and terms commonly used by experts in the field of carbon LCA. For example:

1. Direct effects and “attributional LCA” share the common trait of endeavoring to quantify the average impacts carbon associated with producing and using a particular unit of fuel. This approach ignores the potential secondary impact on the margins of the economic/resource system.

2. Co-product effects are often included within the primary (direct) effects analysis of a fuel, even though the co-product’s relevance (in terms of GHG emissions) often exists outside of the supply-chain of the fuel. In addition, the method used to quantify the CI value impact of a co-product (e.g. substitution vs. allocation) dictates to what degree “outside” market forces are taken into account in the analysis. As such, co-product effects do not fit simply into any one category, and should be defined independently.

3. Indirect effects and “consequential LCA” share the common trait of endeavoring to predict the market-mediated effect of a change in the marketplace, often along the margins of the economic/resource system. The rationale is that any significant change in the marketplace will cause a market response, and the fuel should be held accountable for this response.

**Table 1.** Different Approaches to Determining CI Values of Fuels

<b>Category A – Direct/Attributional LCA</b>	
Direct Effects	Attributional LCA
All significant effects within the primary production chain or life cycle (cradle to grave)	All significant impacts attributable to producing and using the fuel
Uses average data	Uses average data
<b>Category B – Indirect/Consequential LCA</b>	
Indirect Effects	Consequential LCA
Market-mediated or other emissions	Predicts the market-mediated or other

occurring outside of the supply chain of the fuel as a consequence of a change in the system	effects of a change in behavior within a predetermined economic or resource system
Uses data that reflect the expected effect of changes on the <b>margin</b> of the system	Uses data that reflect the expected effect of changes on the <b>margin</b> of the system
Note: The common focus on the margin in Category B should not be construed as a limitation of consequential LCA, as consequential modeling often goes far beyond marginal data into complex economic relationships	

## 2.1 Recommendations to ARB (Immediate)

- 1) **A clear set of definitions of relevance to the determination of direct and indirect effects for all fuels should be adopted and used by CARB for the ongoing development of the LCFS.**
- 2) **ARB should clearly articulate the differences between direct and indirect effects, and attributional and consequential LCA as a function of fuel type.**

## 3.0 Marginality – Definition and Approach

### 3.1 LCA Methods Utilized by the CA LCFS

The final LCFS regulation approved in April 2009 does not commit to one type of carbon LCA or another. In some cases, the Lookup Table relies on an attributional LCA approach based on average California data. In other cases, it takes a consequential LCA approach based on data and modeling designed to forecast the effect of the fuel change on the margin of the system. In some cases (e.g. electricity), the Lookup Table contains separate CI values based on attributional, average LCA and consequential, marginal LCA. The CA LCFS approach for carbon accounting is summarized below:

**Table 2.** Methods Used by CA LCFS to Determine CI Value of Fuel, by Major Fuel Type

<b>Fuel Type</b>	<b>Method of Deriving CI Value</b>	<b>Type of Data Used</b>	<b>Assessed for Impact on the Margin by CARB/LCFS?</b>
<b>Petroleum</b>	Direct, attributional	Average CA	No <sup>1</sup>
<b>Natural Gas</b>	Direct, attributional	Average by fuel type/region	No <sup>1</sup>
<b>Biofuels</b>	Combination of direct, attributional & indirect, consequential	Average by fuel type/region; worldwide marginal for land use impact	Yes. Included by substituting indirect/consequential/marginal land impact in place of direct/attributional land use impact
<b>Electricity</b>	Combination of direct, attributional & indirect, consequential	Average CA for one pathway; marginal CA for another pathway	Marginal CA pathway gets credit for assumed renewable energy and high efficiency NG on margin of electricity sector
<b>Hydrogen</b>	Direct, attributional	Average by fuel type	No <sup>1</sup>

Several facts emerge from the table above: (1) the LCFS does not rely on one type of LCA approach to assign CI values to different fuels; (2) in some cases average data is used, in other cases marginal data/analysis is used; (3) the LCFS looks at the margin of the system in primarily two places, to assign land use impacts to biofuels and to assign clean power credits to electricity.

### 3.2 Marginality as a Threshold Question

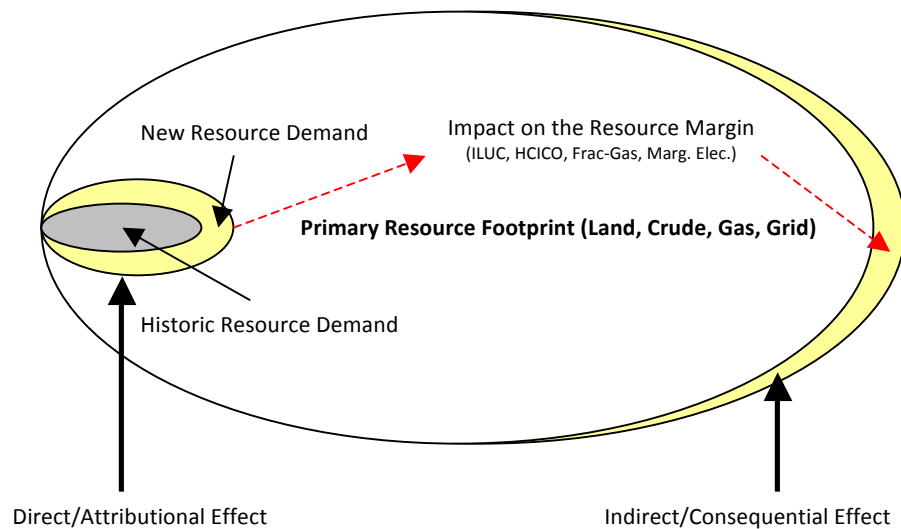
As discussed above, the current LCFS relies on marginal data for some fuel pathways and average data for others. This becomes an issue in the context of “indirect effects of other fuels” because a fuel’s impact on the margin of its primary resource (or system) could be considered its primary indirect effect.

For example, indirect land use change (ILUC) as defined in the LCFS is the calculated impact of using more biofuels on the worldwide margin of the primary resource being utilized to produce the fuel (e.g., land). CARB staff used an economic model (GTAP) to predict this “marginal resource impact” and the calculated CI values associated with this

<sup>1</sup> The CA LCFS supporting documentation does not contain any type of scientific analysis covering this issue.

activity. The approach taken by CARB is a variant (based on a completely different modeling capability) of the approach used by Argonne National Laboratory in its assessment of the lifecycle GHG emissions of corn ethanol prepared in 1999 using GREET.<sup>2</sup>

If the LCA approach used for biofuels is the standard for other fuels, then the first order of business for the EWG-IE is determining the impact of producing a given quantity of other fuels on the resource margin. The rationale, shown in Figure 1, is that all resources (e.g. crude oil, natural gas, electricity produced from various natural resources) are finite. The marginal impact may be large in some cases and small in others, but it would be incorrect to assume zero if other fuels are being assessed for their impact on the resource margin.



**Figure 1.** Basic Framework of Marginality Issue

As such, marginality is a threshold question, and if marginality is within the LCA for some fuels, then the LCFS Lookup Table should include marginal resource impacts for all fuels (unless determined to be zero by scientific analysis). This initial method of inquiry is entirely consistent with looking at the indirect effects of other fuels, which according to the Expert Workgroup guidelines includes looking at the “secondary effects in the energy market.”<sup>3</sup> The different fuel pathways should then be analyzed as follows:

<sup>2</sup> M. Wang, C. Saricks, and D. Santini. “Effects of Fuel Ethanol Use on Fuel-Cycle Energy and Greenhouse Gas Emissions,” January 1999. <http://www.transportation.anl.gov/pdfs/TA/58.pdf>

<sup>3</sup> See [http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/lcfs\\_ewg\\_guidelines.pdf](http://www.arb.ca.gov/fuels/lcfs/workgroups/ewg/lcfs_ewg_guidelines.pdf), p. 2.



**Table 3.** Three Step Process for Determining CI Values, by Major Fuel Type

<b>Fuel Type</b>	<b>Step 1: Determine Direct Emissions</b>	<b>Step 2: Determine Marginal Resource Penalty</b>	<b>Step 3: Determine If Other Significant Indirect Effects Exist</b>	<b>Discussion</b>
<b>Petroleum</b>	Direct, attributional based on GREET	Incremental impact on the margin of the crude oil resource as the demand for gasoline and diesel changes	See chart presented by EWG-IE	Crude oil is a finite resource. An increase in California's consumption of any particular type of oil increases the global consumption rate of that oil, and in much the same way as land use change pushes production to the margin, this effect pushes worldwide oil production to the margin of the resource, which tends to involve greater political, geographic, technological and environmental risk, and more carbon intensive fuels. <sup>4</sup>
<b>Natural Gas</b>	Direct, attributional based on GREET	Incremental impact on the margin of the electricity production resource as the demand for natural gas for vehicles draws it away from power	See chart presented by EWG-IE	Natural gas is a finite resource. Increased demand in vehicle markets will impact electricity producers and likely drive up price. Recently published work from UC-Davis suggests that marginal change in electricity production increases emissions. <sup>5</sup> There is also the issue of the natural gas along

<sup>4</sup> See [http://cdmc.epp.cmu.edu/docs/pub/Farrell\\_Brandt.pdf](http://cdmc.epp.cmu.edu/docs/pub/Farrell_Brandt.pdf)

<sup>5</sup> See [http://www.sciencedirect.com/science?\\_ob=ArticleURL&\\_udi=B6TH1-4XH5MJH-4&\\_user=10&\\_coverDate=04%2F02%2F2010&\\_rdoc=1&\\_fmt=high&\\_orig=search&\\_sort=d&\\_docanchor=&view=c&\\_searchStrId=1427095080&\\_rerunOrigin=google&\\_acct=C000050221&\\_version=1&\\_urlVersion=0&\\_userid=10&md5=835aaa8b17742296fa8cf6246973292e](http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6TH1-4XH5MJH-4&_user=10&_coverDate=04%2F02%2F2010&_rdoc=1&_fmt=high&_orig=search&_sort=d&_docanchor=&view=c&_searchStrId=1427095080&_rerunOrigin=google&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=835aaa8b17742296fa8cf6246973292e)

		production; some data suggests new growth in gas markets with higher CI		the margin of the natural gas industry itself and the potential increased emissions associated with hydrofracture recovery techniques.
<b>Biofuels</b>	Direct, attributional based on GREET	Incremental impact on the margin of the land resource as the demand for land increases (i.e. ILUC)	See chart presented by EWG-IE	As discussed, the LCFS already debits biofuels for its impact on the worldwide (land) resource margin, as forecasted by a CGE model. The LCFS should incorporate the best available science, as it evolves, in a reasonable timeframe.
<b>Electricity</b>	Direct, attributional based on GREET	Incremental impact on the margin of the electricity production resource as the demand for electricity increases	See chart presented by EWG-IE	Electricity production relies on the combustion or use of finite natural resources (coal, natural gas, biomass, etc.). Electricity currently takes a credit for its impact on the margin, but recently published work from UC-Davis suggests that electricity should be taking a penalty for its impact on the resource margin. <sup>6</sup>
<b>Hydrogen</b>	Direct, attributional based on GREET	Incremental impact on the margin of the electricity production resource as the demand for electricity increases	See chart presented by EWG-IE	See discussion in electricity section. If hydrogen penetrates the market significantly, it will add additional demand to regional electricity systems with unique load profiles. Recently published work from UC-Davis suggests that fuel production that relies on electricity could increase emissions on the resource margin. <sup>7</sup>

<sup>6</sup> See note 4.

<sup>7</sup> See note 5.

### 3.1 Recommendations to ARB

- 1) The LCFS should carbon score fuels symmetrically, to ensure a level playing field for the LCFS
- 2) The LCFS should use average and marginal data across different fuel pathways in a consistent manner
- 3) Where there are data gaps that prevent symmetrical carbon scoring, they should be recognized and filled by prioritized research projects.

### 4.0 The Impact on the Margin of Petroleum

As discussed in Table 3, ILUC is the equivalent of assessing biofuels for its impact on the (land) resource margin (i.e. as a driver of new land conversion). It is well-recognized that other fuels (i.e. fuels other than biofuels) have impacts along the margin of the primary resource being utilized to produce the particular fuel (i.e. crude oil reserves, natural gas reserves, or finite resources used to produce electricity).<sup>8</sup> As such, the first place to look with regard to assessing the potential indirect effects of other fuels is along the margin of the primary resource used to produce the fuel. The EWG-IE team has discussed this effect since first being formed, and two different perspectives on this issue materialized over time; each is presented below. Section 4.1 approaches this question from the perspective that if alternative fuels are assessed on the resource margin, then marginal petroleum impacts should also be included in the LCFS. The alternative perspective is presented in section 4.2.

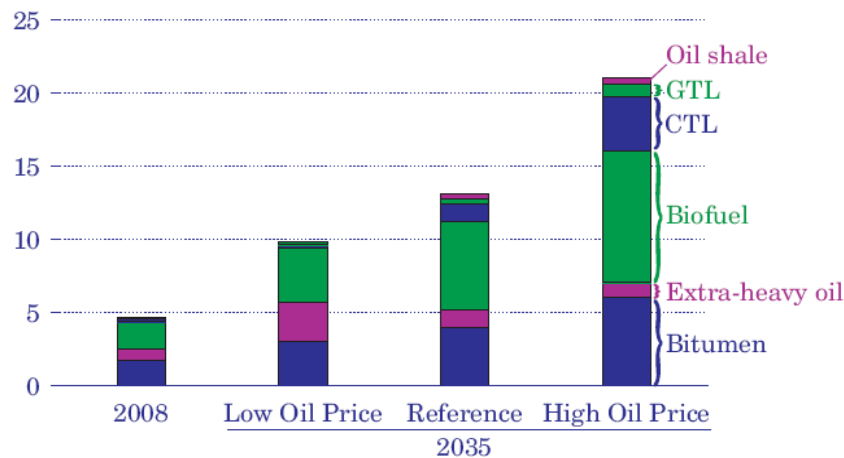
#### 4.1 Perspective 1: Inclusion of Marginal Petroleum as an Indirect Effect

It is clear that world oil markets are already moving away from a depleting conventional, light sweet crude resource.<sup>9</sup> As discussed in a recent paper by A.R. Brandt et al., “one

<sup>8</sup> “The Impact Of Land Use Change On Greenhouse Gas Emissions From Biofuels And Bio-liquids,” an in-house review conducted for DG Energy as part of the European Commission's analytical work on indirect land use change (July 2010); McCarthy, Ryan W. and Christopher Yang (2009) Determining Marginal Electricity for Near-term Plug-in and Fuel Cell Vehicle Demands in California: Impacts on Vehicle Greenhouse Gas Emissions. *Journal of Power Sources*; see also [http://pubs.its.ucdavis.edu/publication\\_detail.php?id=1362](http://pubs.its.ucdavis.edu/publication_detail.php?id=1362).

<sup>9</sup> See Figure 1 (below); see also <http://www.onepetro.org/mslib/servlet/onepetroreview?id=SPE-120174-MS&soc=SPE>, <http://priceofoil.org/wp-content/uploads/2009/05/shelliefinal.pdf>, [http://www.cbecal.org/pdf/Wilmington\\_Refineries\\_report\\_final.pdf](http://www.cbecal.org/pdf/Wilmington_Refineries_report_final.pdf), <http://www.apen4ej.org/chevron.htm>, [http://www.blastinvest.com/value-investing-newsletter/05\\_31\\_2005.htm](http://www.blastinvest.com/value-investing-newsletter/05_31_2005.htm), <http://www.heatingoil.com/blog/interest-in-sour-crude-futures-show-influence-of-saudi-arabia-and-gulf-of-mexico1216/>, <http://www.highbeam.com/doc/1G1-157194605.html>, <http://www.thefreelibrary.com/SAUDI+ARABIA+-+Part+2+-+The+Oil+Production+Profile+&+Fields-a0169325394>, <http://www.investmentu.com/IUEL/2009/November/new-crude-oil-benchmark.html>, <http://www.theoilrum.com/node/2707>, <http://www.netl.doe.gov/energy->

certainty is that the ‘oil transition’, or the transition to substitutes for conventional petroleum, has begun.”<sup>10</sup> As such, the use of a given unit of a finite and exhaustible conventional oil resource accelerates the depletion of this resource and drives other oil companies to crude oil located on the resource margin. Recent oil market forecasts bear this reality out. Figure 2 demonstrates that unconventional sources of oil are forecasted to play an increasing role along the margin of world oil markets. As shown, world oil production of liquid fuels from unconventional resources jumps from roughly 5 percent of total liquid fuels production in 2008 to 10, 13, and 21 percent of total world liquid fuels production by 2035 in the Low Oil Price, Reference and High Oil price cases, respectively.



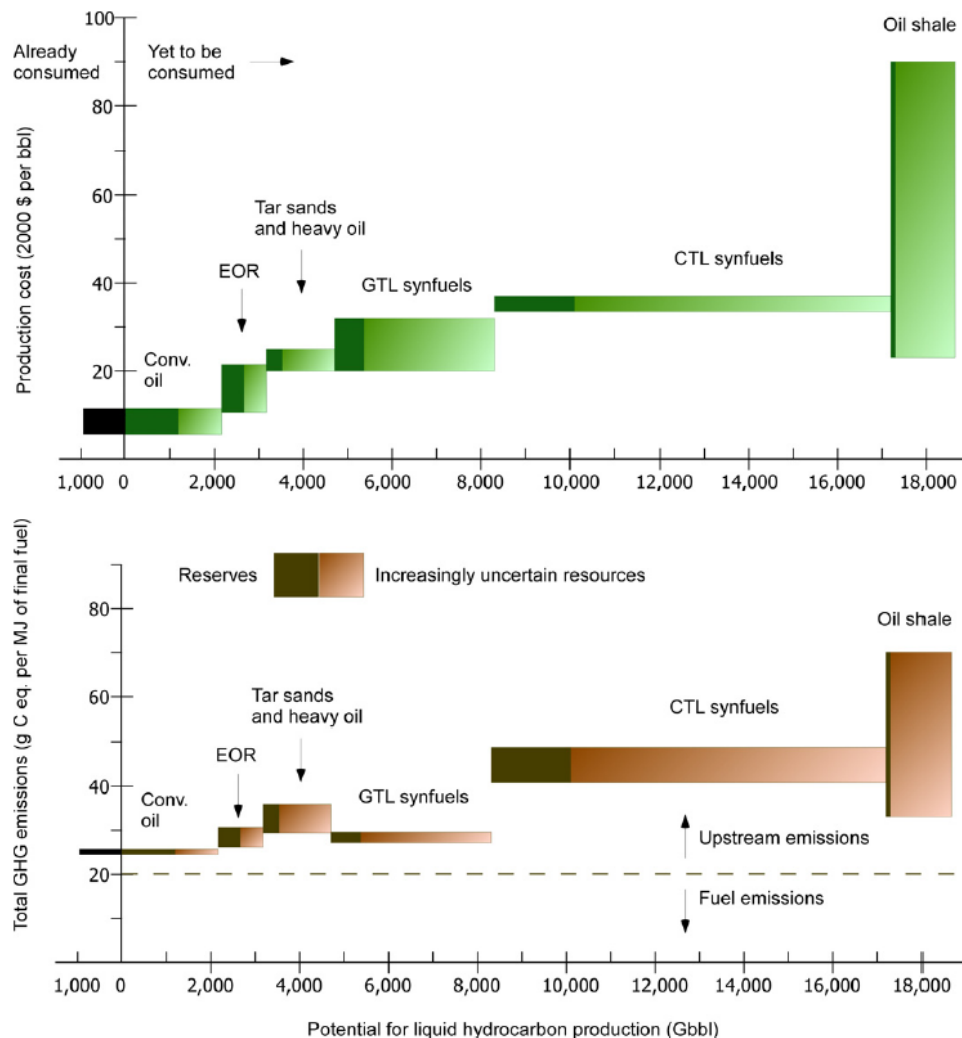
**Figure 2.** Unconventional resources as a share of total world liquids production in three cases (low oil, reference, and high oil price), comparison between 2008 and projected 2035 levels (Source: EIA AEO 2010)

While fuel-carbon LCA researchers have not analyzed marginal oil resource impacts to the degree that they have modeled marginal land resource impacts, there are several studies of note. A 2006 analysis conducted by Alex Farrell and Adam Brandt entitled *Risks of the Oil Transition* conducted an open literature review on the costs and GHG emissions associated with the transition from conventional to unconventional and heavier sources of oil (Figure 3). The paper suggests that the marginal barrel of oil may be both more expensive and more carbon intensive. It should be noted that the Brandt study provides a general overview of the transition from conventional to non-conventional oil over a long time period.

[analyses/pubs/Life%20Cycle%20GHG%20Analysis%20of%20Diesel%20Fuel%20by%20Crude%20Oil%20Source%20.pdf](http://www.geoexplor.com/hydrocarbo/heavyoil/),  
[http://www.geoexplor.com/hydrocarbo/heavyoil/](http://www.reuters.com/article/idUSN1521414320100315), <http://www.reuters.com/article/idUSN1521414320100315>

<sup>10</sup> See Brandt AR, Plevin RJ and Farrell AE, Dynamics of the oil transition: Modeling capacity, depletion, and emissions, *Energy* 35 (2010) 2852-2860.

A number of other researchers have also attempted to define the marginal barrel of oil under certain sets of scenarios. For example, in examining the impacts of carbon-constraints on crude profiles up to the year 2100, Persson et al. (2007) found that while the supply of coal/oil shale and heavy crude/tar sands is reduced, those sources are nonetheless on the margin beginning in 2010.<sup>11</sup> The study suggests that the marginal barrel has a carbon intensity of at least 120 g/MJ.<sup>12</sup> David Greene of the Oak Ridge National Laboratory has also released several papers and presentations on the issue.



**Figure 3.** Global supply of liquid hydrocarbons in dollars (top) and carbon emissions (bottom).  
(Source: A E Farrell and A R Brandt 2006 *Environ. Res. Lett.* 1 014004)

<sup>11</sup> See Persson et.al. (2007) Major oil exporters may profit from rather than loose, in a carbon constrained world, *Energy Policy* 35, pp. 6346-6353.

<sup>12</sup> "The Impact Of Land Use Change On Greenhouse Gas Emissions From Biofuels And Bio-liquids," an in-house review conducted for DG Energy as part of the European Commission's analytical work on indirect land use change (July 2010), p. 210.

A July 2010 review of the literature conducted as part of the European Commission's ongoing analysis of ILUC pursuant to the EU's Renewable Energy Directive concludes that the marginal impacts for petroleum have been identified to a certain degree, and "while studies in the literature that attempt to identify the long-term marginal fossil fuel source have concluded in different ways, none seems to assume that conventional crude is the marginal source."<sup>13</sup> More specifically, the analysis showed that: (1) marginal petroleum has a higher financial cost per gallon than conventional petroleum; and, (2) marginal petroleum has a higher GHG emission profile than conventional petroleum.<sup>14</sup> The study includes a literature review conducted of recent findings (see Figure 4).

Pathway	g CO <sub>2</sub> eq./MJ	Source:
RFA Technical Guidance value	86	Mortimer et al. (2008), p.24.
– Diesel		
RFA Technical Guidance value	85	
– Petrol		
GREET model, conventional low sulphur – Diesel	87	
GREET model, conventional low sulphur – Petrol	97	
GREET model, tar sands	~ 140	Kim et. al.
Conventional Gasoline	93.3	
Gas-to-Liquids	100 – 109	
Bitumen (Tar sands)	107.7 – 131.5	RFA (2009), p.4.
Extra Heavy Crude	107.7 – 131.5	
Oil Shale	120.9 – 256.9	
Coal-to-Liquids	153.2 – 178.7	
Conventional Gasoline / Diesel	94.2 / 93.5	
Enhanced Oil Recovery	96.1 – 112.6	
Gas-to-Liquids	100.1 – 108.9	Brandt and Farrell (2007), p.249.
Tar sands / Extra heavy oil	107.8 – 131.6	(with own conversion calculations)
Oil shale	121 – 256.7	
Coal-to-Liquid	153.3 – 178.6	
EPA proposed rule Diesel fuel	102.1	EPA (2009), p.313 <sup>868</sup> .
EPA proposed rule Gasoline	103.8	
EPA final rule Diesel fuel	102.3	EPA (2010), p.256 and 259 <sup>869</sup> .
EPA final rule Gasoline	103.6	
Renewable Energy Directive	83.8	Directive 2009/28/EC

**Figure 4.** Variation of GHG emissions from petroleum with the corresponding source<sup>15</sup>

<sup>13</sup> "The Impact Of Land Use Change On Greenhouse Gas Emissions From Biofuels And Bio-liquids," an in-house review conducted for DG Energy as part of the European Commission's analytical work on indirect land use change (July 2010), p. 210.

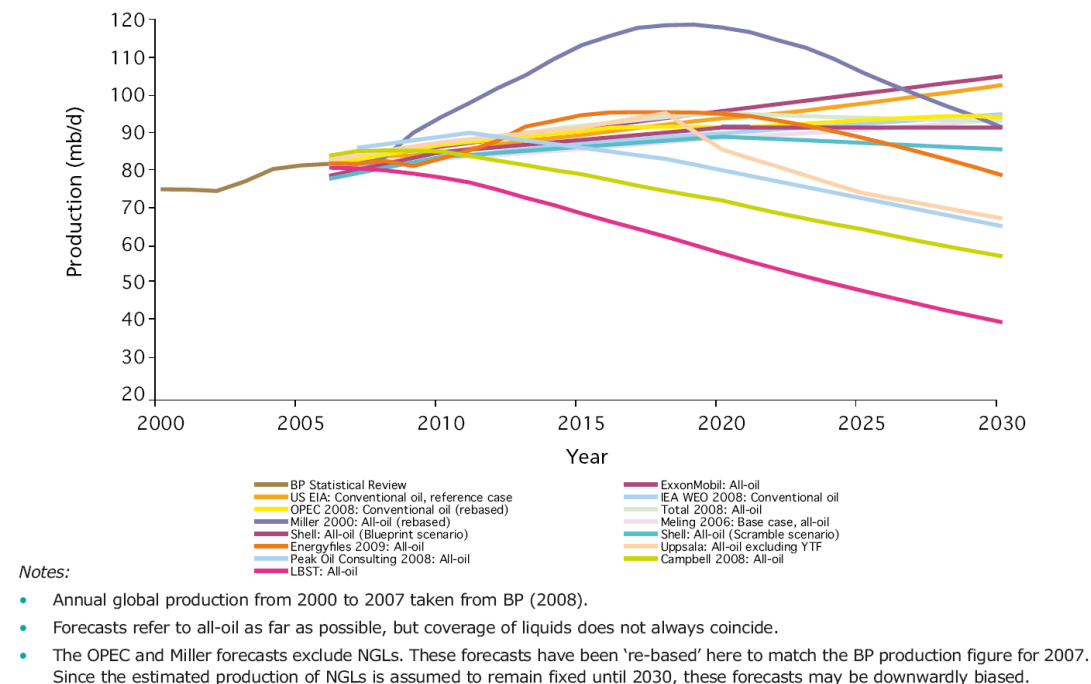
<sup>14</sup> While the linkage varies between higher production costs and higher GHG emissions, the literature review concludes that, on balance, more expensive crude generally has more GHG emissions than lower cost crude. Arctic and deep water extraction is often the exception; however, the study claims that neither of these sources is expected to play a major role in developing new crude stocks.

<sup>15</sup> See note 8

## 4.1.1 Substitution of fossil fuels with biofuels

### 4.1.1.1 Prediction of future oil production

The preceding section illustrates that the marginal oil is more expensive and carbon intensive. This reflects the limited resources of lighter crude oils and the growing importance of unconventional resources<sup>16</sup>. But the predictions of the future oil production vary widely. The UK Energy Research Center compared fourteen forecasts of the future of global oil supply up to 2030 (see Figure 5)<sup>17</sup>. The comparison focuses primarily on forecasts of conventional oil supply up to 2030. Nine of these forecasts predict a peak in conventional oil production before 2030, while five do not.



**Figure 5.** Comparison of fifteen forecasts of oil production to 2030

Despite the uncertainties there are many signs for a tendency to more carbon intensive fossil fuels:

- Due to the manner in which the production decline rate is developing, the IEA anticipates a powerful decline in production in all oil fields from 70 million barrels/day in 2007 to 27.1 million barrels in 2030 (see Figure 5).

<sup>16</sup> Sandrea & Sandrea 2007. Global Oil Reserves – Recovery Factors Leave Vast Target for EOR Technologies. In: Oil & Gas Journal, November 2007, EIA 2010. Annual Energy Outlook 2010, 2010, IEA 2008. World Energy Outlook 2008, See Figure S2 in Appendices

<sup>17</sup> UK Energy Research Center 2009. Global Oil Depletion: An assessment of the evidence for a near-term peak in global oil production.

- The production of unconventional fuels is growing. Compared to 2000, the production of unconventional fossil fuels has tripled.<sup>18</sup> Recent global energy outlooks predict a strong increase in the production of unconventional fuels to cover the rising energy demand.
- The depths of the oil fields is growing. In the future, deep-sea drilling will grow in importance, as indicated by the recent petroleum discoveries in the Gulf of Mexico and off the shores of Brazil and Africa. Offshore oil fields already contribute one third of global petroleum production.<sup>19</sup> According to Llewelyn, 15% of them are deep-sea deposits.<sup>20</sup> Yet onshore drillings are also becoming deeper. For example, in Russia the average drilling depth has doubled since 1960, now reaching 3,000 to 4,000 m. In the future, depths of 5,000 to 6,000 m can be expected.<sup>21</sup> According to IHS and Credit Suisse, around 30% of remaining global oil reserves is located at a depth greater than 3,000 m.<sup>22</sup>
- The water to oil ratio (defined as the ratio of produced water to produced oil) will also continue to deteriorate worldwide, as, the older the field, the greater the decline of production amounts and the greater the proportion of water rises.<sup>23</sup> In Canada, for example, the WOR of petroleum production in the province of Alberta has risen sharply in recent years and increased from 11.6 to 14.8 between 2000 and 2003 alone. As oil fields become deeper, yielding a greater water to oil ratio, the greenhouse gas emissions from petroleum production also increase. According to Jacobs Consultancy in a 20,000 feet deep field, emissions from lifting the oil and water reinjection grow nearly fourfold through an increased water to oil ratio from 3:1 to 15:1.<sup>24</sup>
- The specific greenhouse gas emissions from oil production in declining fields are rising due to the use of enhanced recovery technologies and the increasing water to oil ratio. The University of Calgary for example anticipates a tripling of carbon intensity from the production of light and medium-heavy petroleum types in Canada by 2020 compared with the average emission values of 2000.<sup>25</sup>

<sup>18</sup> Era 2009. The impact of fossil fuels. Greenhouse gas emissions, environmental consequences and socio-economic effects. according to BGR 2009. BGR (Bundesanstalt für Geowissenschaften und Rohstoffe) 2009: Energierohstoffe 2009. Reserven, Ressourcen, Verfügbarkeit. Erdöl, Erdgas, Kohle, Kernbrennstoffe, Geothermische Energie. [www.energy-research-architecture.com](http://www.energy-research-architecture.com)

<sup>19</sup> IEA 2008. see note 15.

<sup>20</sup> Llewelyn quoted in Chang 2007. Massive deep-water oil find in Brazil challenges technology. 1/12/2007.

<http://www.mcclatchydc.com>. David Llewelyn is a petroleum expert from Crondall Energy Consultants.

<sup>21</sup> Matveichuk 2005. The Energy Vector of the 21st Century. In: Oil of Russia magazine, No. 1, 2005. [www.oilru.com](http://www.oilru.com).

<sup>22</sup> Sandrea & Sandrea 2007 see note 15.

<sup>23</sup> Maersk Oil 2008. Environmental Status Report. The Danish North Sea 2007. A.P. Moller – Maersk Group

<sup>24</sup> Jacobs Consultancy 2009. Life Cycle Assessment. Comparison of North American and Imported Crudes. Report for the Alberta Energy Research Institute by Jacobs Consultancy and Life Cycle Associates.

<sup>25</sup> Timilsina et al. 2006. GHG Emissions and Mitigation Measures for the Oil & Gas Industry in Alberta. Paper No. 7 of the Alberta Energy Futures Project.



- Heavy oil is becoming increasingly important to global crude supplies. There are currently existing and planned heavy oil projects in Venezuela, Columbia, Brazil, Mexico, Ecuador, Canada, Kuwait, Saudia Arabia, Iran, China and the North Sea.<sup>26</sup> In global petroleum production, the proportion of heavy, sulphurous crude oils is growing and that of the lighter, low-sulphur types, which currently make up just 20% of global production, is declining.<sup>27</sup>

The listed developments above show that the carbon intensity of fossil fuels is not only growing because of unconventional fuels but also because of conventional petroleum. This tendency has not only an important impact on the average but also on the marginal barrel. The following chapters explain that biofuels will likely not only reduce future unconventional but also conventional fossil fuel production. In addition, the marginal conventional barrel replaced with biofuels will be derived from the petroleum resources listed above that require more energy and material and therefore have a higher carbon intensity than the average barrel.

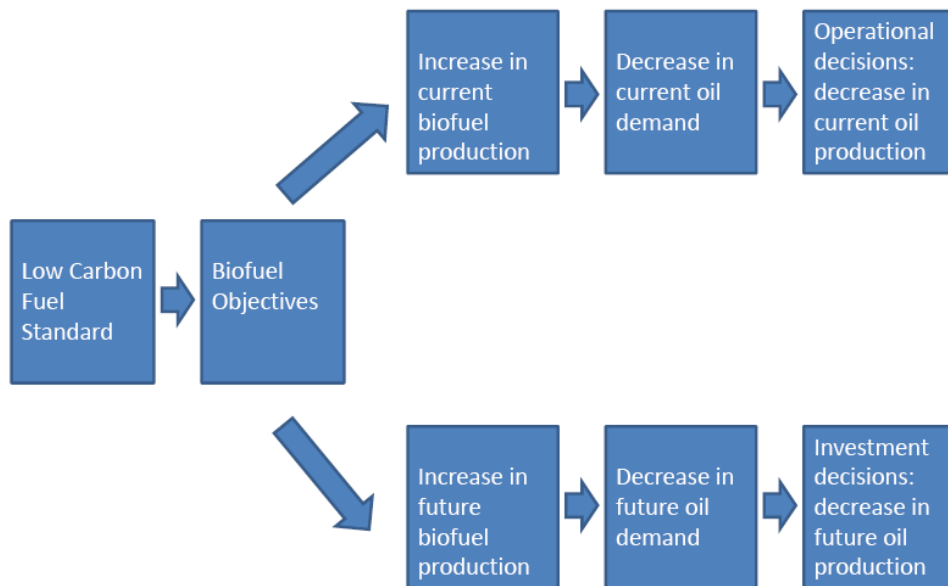
According to economic theory, the marginal supplier in a decreasing market will be the least competitive supplier because this supplier will be the one going out of business as a result of reduced demand. Therefore biofuels displace the fossil fuel with the lowest profit margin. But due to market distortions the replacement of fossil fuel through biofuels depends on many factors that influence operational and investment decisions in the short-, medium- and long-term.

#### **4.1.1.2 Potential Short-term effects**

In the short term an increase in the current biofuel production has above all an effect on operational decisions (see Figure 6). As investments for new oil production capacity including investments in expanded production capacity not fully utilized represent sunk costs, the increased biofuel production level cannot influence them.

<sup>26</sup> [http://www.heavyoilinfo.com/feature\\_items/heavy-crude-oil-a-global-analysis-and-outlook](http://www.heavyoilinfo.com/feature_items/heavy-crude-oil-a-global-analysis-and-outlook), <http://www.rigzone.com>, Bloomberg 2010. Mideast Oil Producers Seek Heavy Crude Output Boost: Week Ahead. May 30, 2010.

<sup>27</sup> Wood 2007. Consequences of a heavier and sourer barrel. In: Petroleum Review April 2007. See also Figure S1 in Appendices



**Figure 6.** Influence of biofuel production on operational and investment decisions

Operational decisions for refineries and crude oil extraction have to be distinguished. For example:

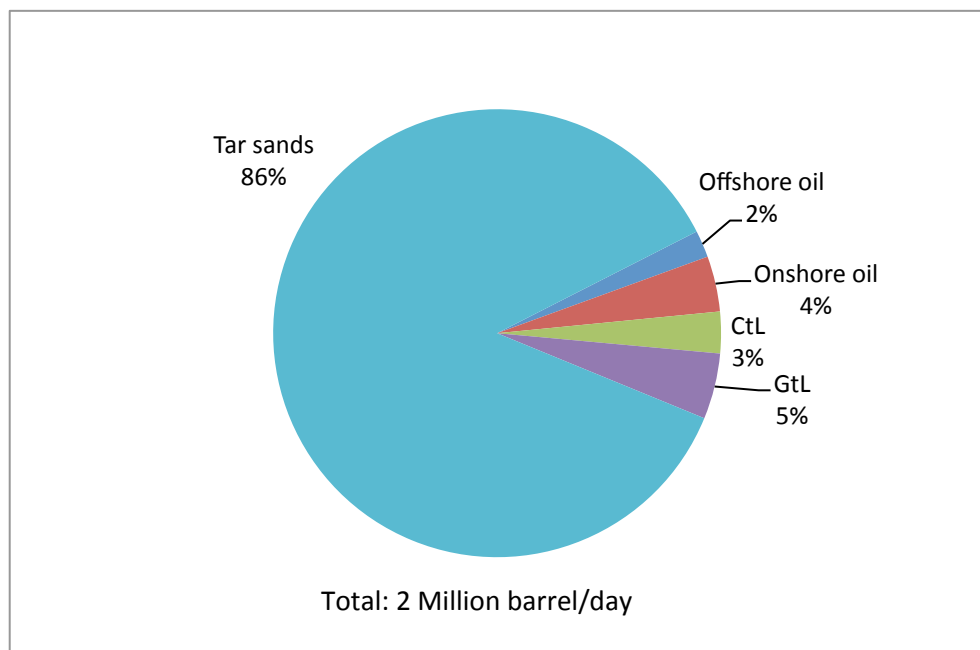
- In capital-intensive refineries, capable of running on heavy and lower-cost crude, the marginal fuel will continually be produced as the retail price is higher than the operating costs. That means that if the profit margin on light crude is less than on heavy crude, refineries will more likely reduce the light crude oil input instead of heavy oil if the amount of biofuels is rising. That is more economical due to the lower price of heavy oil and sunk costs in the refining infrastructure.
- In the short term and on a macro scale, crude oil extraction is mainly influenced by OPEC Production cuts. When the worldwide recession caused the oil price to decline in the 3<sup>rd</sup> quarter of 2008, the OPEC reduced their quota by over 3 million barrel/day, while non-OPEC production remained on a constant level.<sup>28</sup> The production of the most expensive oil, such as tar sands and deep water oil, which are mainly produced in non-OPEC countries, did not decrease. This may indicate some fields will continue to produce as long as the retail price is higher than the production costs.

<sup>28</sup> Energy Comment 2010. Global Oil Briefing. No.34 14 March 2010. [www.energycomment.de/wp-content/uploads/2010/05/GOB34-english2.pdf](http://www.energycomment.de/wp-content/uploads/2010/05/GOB34-english2.pdf). Barclays Capital 2010. Oil Sketches - The Oil Crunch. [http://www.odac-info.org/sites/default/files/OIL\\_SKETCHES\\_CRUNCH\\_102535992.pdf](http://www.odac-info.org/sites/default/files/OIL_SKETCHES_CRUNCH_102535992.pdf)

In relation to the second bullet above, it is important to keep in mind that we do not know how global oil production would have developed without the recession. While unconventional oil production (tar sands etc.) may have remained constant during the recession, new unconventional oil projects may have been cancelled or delayed due to the recession (see section below).

#### 4.1.1.3 Potential Medium- and Long-term Effects

Over the medium- and long-term, an increase in future biofuel production has above all an effect on investments decisions (see Figure 7). Biofuel objectives reduce the profit chances on future crude oil production. Those biofuel objectives therefore endanger yields of the more expensive and riskier marginal sources, causing international oil companies (IOCs) to invest less in these technologies, as they act upon yields, are liable to strict accountancy rules and have to refinance on the financial market. The worldwide recession has already caused investment cuts in oil production. Although representing only 10% of total investment, over 85% of the projects that have been canceled or deferred were oil sands projects (see Figure 7).<sup>29</sup> It is noted that onshore, offshore, CTL and GTL projects were among those cancelled.



**Figure 7.** Cancelled oil projects between October 2008 and September 2009. Source: IEA 2009.

<sup>29</sup> IEA 2009. World Energy Outlook 2009.

The influence of OPEC productions cuts will fall in the medium- and long- term:

- The compliance rate of OPEC members is decreasing and fell to 53% in July 2010.<sup>30</sup>
- The influence on global oil production of national oil companies (NOCs) and state-owned enterprises (SOEs) is growing and may undermine OPEC's ability to 'set prices.' Chinese, Russian and Indian NOCs and SOEs are increasingly investing in OPEC-Countries such as Venezuela, Nigeria and Iran.<sup>31</sup> Bilateral contracts between OPEC-countries and NOCs and SOEs will aggravate production shortenings of the OPEC, as contractually appointed oil supplies have to be delivered.
- Singular interests of the OPEC members will prevent long term production cutbacks, as the OPEC countries depend on income from oil export and some may be more dependent than others and not as able to reduce production.
- OPEC members have to invest in new production capacity due to the strong production decline of existing fields. The IEA predicts that production at existing fields will decrease by 17 mb/d in OPEC countries over 2007-2030 (see Figure S1, Appendices).<sup>32</sup>
- OPEC members will also have to increase their production to compensate for their own national rise in oil consumption due to high fuel price subsidies<sup>33</sup> and economic growth. The national oil company of Saudi Arabia Aramco predicts that domestic oil demand will rise by 250% until 2028 and shorten the oil available for export by 3mb/d over the period to less than 7 mb/d.<sup>34</sup> If domestic growth follow the predicted trajectory Saudi Arabia spare oil-production capacity and the new projects will increasingly be used to feed local demand.
- Political objectives limit future possibilities for OPEC productions cuts. According to the IEA World Energy Outlook from 2008, Iraq will make (after Saudi Arabia) the second biggest contribution to OPEC production growth. But Iraq is the only OPEC member not bound by a production quota.<sup>35</sup>

Regardless of the declining influence of the OPEC cartel biofuels will affect investments of OPEC members in the same way as other countries. Therefore biofuel objectives may reduce marginal OPEC production in the future. The following figure illustrates the impact of the worldwide recession on OPEC and non-OPEC oil production. Between

---

<sup>30</sup> IEA Oil Market Report June 2010. Angola, Iran, Venezuela and Qatar are the OPEC states that have been least compliant over the past 18 months with the record 4.2 million barrels per day of cuts that the group agreed upon in late 2008. Angola failed to implement any of its implied share of those cuts, Qatar was only 16 per cent compliant with the cuts, Iran being 16 % compliant and Venezuela 33 % compliant. This exceeded the OPEC-11 target by 1.975 million b/d and puts the group's compliance rate at 53%, with the 4.2 million-barrel-per-day production cuts agreed to in late 2008 (and effective as of January 2009 ).

<sup>31</sup> Brune, N. E. 2010. Years Later: OPEC's Continuing Threat to American Security. Journal of Energy Security. 29 September 2010.

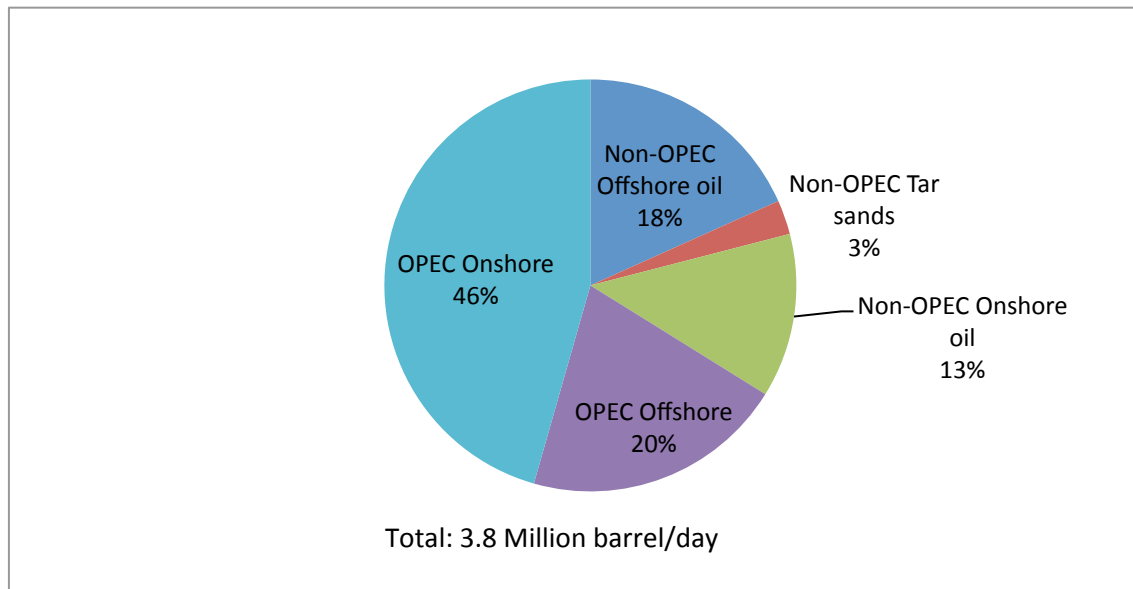
<sup>32</sup> IEA 2008 see note 15.

<sup>33</sup> Global Subsidies Initiative 2009. The Politics of Fossil-Fuel Subsidies. [www.globalsubsidies.org/files/assets/politics\\_ffs.pdf](http://www.globalsubsidies.org/files/assets/politics_ffs.pdf)

<sup>34</sup> Petroleum Economist 2010f. Saudi Aramco wrestles its domestic energy-consumption problem. June 2010

<sup>35</sup> IEA 2008, see note 15

October 2008 and September 2009 projects in OPEC member states with over 2 million barrels per day capacity were postponed but not cancelled (see Figure 8)



**Figure 8.** Postponed oil projects between October 2008 and September 2009. Source: IEA 2009.

The national oil companies (NOCs) and state-owned enterprises (SOEs) are not only influencing OPEC oil production but also the exploitation of risky and marginal oil reserves. NOCs and SOEs, especially in China and India, are securing crude oil reserves as strategic assets.<sup>36</sup> NOCs and SOEs do not have to refinance on the financial market and use public financial sources instead, thus reducing investment risks that mainly concern oil reserves. These investments are part of a strategy of the emerging countries China, India and Brazil to globally secure commodities in developing nations. But the yield orientation of demand-NOCs increases, e.g. for PetroChina, which already sells a significant amount of its crude oil to the global market and does not supply its own national market past that.<sup>37</sup> When biofuels can create an alternative to marginal oil, NOCs will participate in biofuel markets. Other sectors of renewable energies are already experiencing these developments. China for example became the biggest wind energy market within only a few years.<sup>38</sup>

The substitution of biofuels for the most expensive crude oil is also influenced by national energy supply objectives regarding regional commodities. For example, Jordan and Morocco are highly interested in exploiting their oil shale reserves to become more

<sup>36</sup> Goldthau, A. and Witte, J. M. 2010. Back to the future or forward to the past? Strengthening markets and rules for effective global energy governance. In: *International Affairs* 85. 2 (2009) 373–390

<sup>37</sup> see note 36

<sup>38</sup> WWEA 2010. World Wind Energy Association) 2010: World Wind Energy Report 2009. [http://www.wwindea.org/home/images/stories/worldwindenergyreport2009\\_s.pdf](http://www.wwindea.org/home/images/stories/worldwindenergyreport2009_s.pdf)

independent of oil imports.<sup>39</sup> Jordan already signed contracts with Shell and the Estonian company Eesti Energia to start exploiting oil shale reserves for their own energy consumption within the next years.<sup>40</sup>

#### 4.1.2 Correlation between the development of production costs and carbon intensity of fossil fuels in the long-term

Despite the uncertainty with regard to availability, costs and emissions analyses conducted by Farrell and Brandt indicate that more expensive crudes are generally connected with higher emissions (see Chapter 4.1). Farrell and Brandt see only GTL as the exemption for the correlation between the level of greenhouse gas emissions and production costs.

In addition, cost curves from the IEA and BP illustrate that GTL has a similar range of production costs as CTL and oil shale (see Figures 9 and 10). The IEA and BP cost curves also show more examples that cost development and carbon intensity of fossil fuels do not run parallel systematically. EOR, deep water and Arctic could be as or even more expensive as tar sands. EOR and deep water also have a wide range of GHG emissions (see Figure 11). According to recent studies the production chain of EOR and deep water can cause emissions as high as the emissions from tar sands.<sup>41</sup>

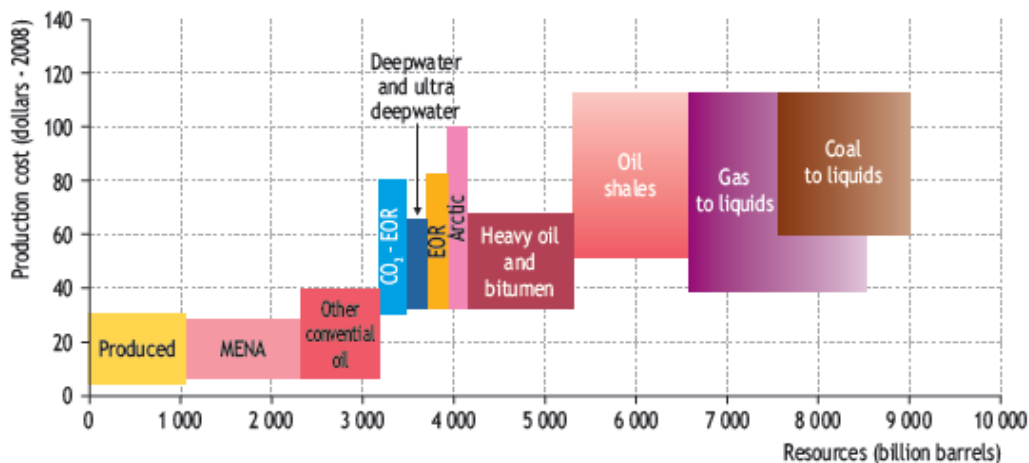


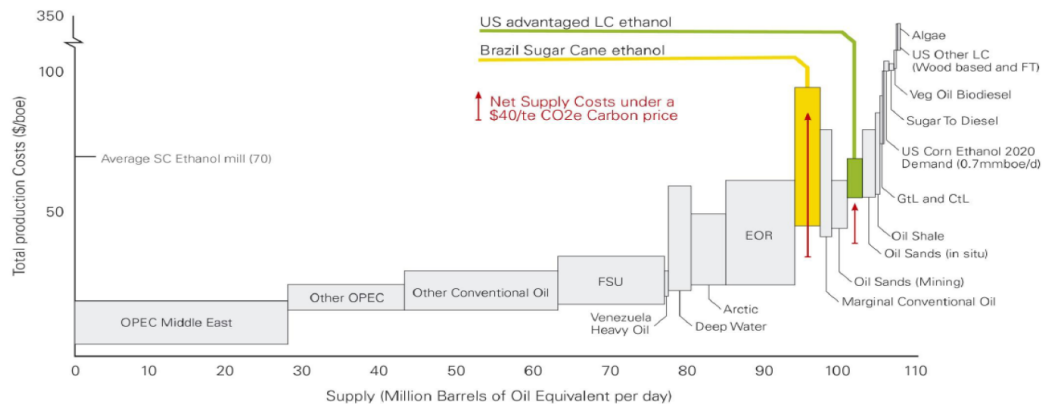
Figure 9. Long-term oil-supply costs curve. Source IEA 200

<sup>39</sup> Sladek, T. 2010. An International Oil Shale Council for Egypt, Jordan, Morocco, Turkey, and Syria Concept Summary. [www.medemip.eu/Calc/FM/MED-EMIP/OtherDownloads/Docs\\_Related\\_to\\_the\\_Region/201002\\_Oil\\_Shale\\_Conference-Sharm\\_El\\_Sheikh/IOSC\\_Report\\_Summary-Jan2010.pdf](http://www.medemip.eu/Calc/FM/MED-EMIP/OtherDownloads/Docs_Related_to_the_Region/201002_Oil_Shale_Conference-Sharm_El_Sheikh/IOSC_Report_Summary-Jan2010.pdf)

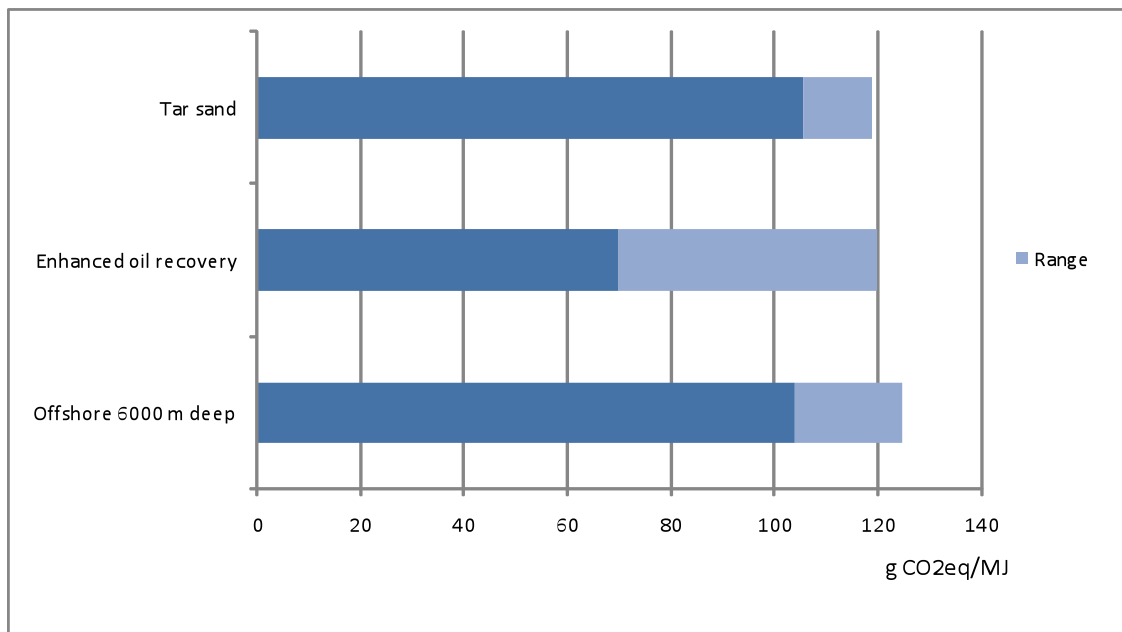
<sup>40</sup> Hafidh, H. 2010. Eesti Energia Clinches Oil-Shale Deal With Jordan. In Wall Street Journal. MAY 11, 2010. <http://online.wsj.com/article/BT-CO-20100511-715895.html>

<sup>41</sup> Jacobs Consultancy 2009 see note 24, Brandt and Unnasch 2010. Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery. In: *Energy Fuels*, 2010, 24 (8), pp 4581–4589. Assumption for max. value of offshore: water to oil ration (WOR) 25:1.

The prediction of whether and over what time period biofuels will replace GTL, CTL or oil shale in the long term (directly or through market-mediated forces) and at what volumetric levels is highly uncertain and depends on many factors. But the earlier conventional oil production is depleted the bigger the pressure to produce fuels not only from tar sands and extra heavy oil but also from coal, gas and oil shale.

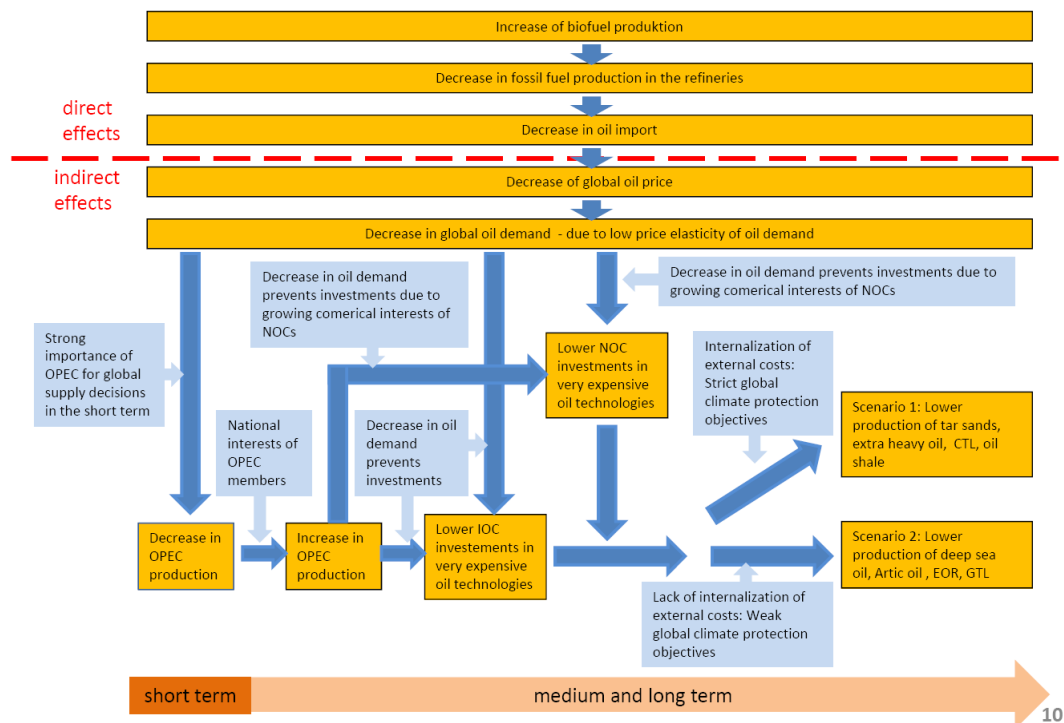


**Figure 10.** Long-term oil-supply costs curve. Source: BP 2009.



**Figure 11.** Green house gas emissions of fossil fuels (WTW). Source: Jacobs Consultancy 2009, Brandt and Unnasch 2010

Studies suggest that huge GTL and CTL (from hard coal) production is not very likely due to competition for this feedstock with other potential applications (mainly in power generation and final uses). That is not the case for CTL from a coal with lower energy content like brown coal (lignite), Underground Coal Gasification (huge quantities of coal can be used) and oil shale. The future of Underground Coal Gasification, which has a very high carbon intensity but relatively low production cost is still uncertain. There are a few pilot projects worldwide but no commercial projects.<sup>42</sup> The prediction of oil shale projects is also very difficult.<sup>43</sup>



**Figure 12: Replacement process of fossil fuels through biofuels.** Source: Pieprzyk 2010

Policy decisions will also influence the marginal oil production in the future. You can compare for example two scenarios (see Figure 12): The first scenario assumes the internalization of external costs of climate change where strict global climate protection objectives will make oil with the highest carbon intensity the most expensive oil. In this scenario a higher biofuel supply leads to a lower production of tar sands, extra heavy oil, CTL and oil shale.

<sup>42</sup> Shafirovich, and Varma, 2009. Underground Coal Gasification: A Brief Review of Current Status. School of Chemical Engineering, Purdue University, Indiana, 1. June 2009. , UCG, Partnership 2009. <http://www.ucgp.com/>

<sup>43</sup> Bartis, 2006. Unconventional Liquid Fuels Overview. 2006 Boston World Oil Conference



Another scenario assumes a lack of internalization of external costs and weak global climate protection objectives. In this scenario deep sea oil, Arctic oil, EOR and GTL are more expensive than the oil with the highest carbon intensity. Therefore biofuels will replace these types of fossil fuels instead of tar sands, CTL or oil shale etc.

#### **4.1.3 Impact of Biofuel Use on Price-Induced Petroleum Demand**

In estimating the impact of biofuel use on petroleum use, an economic argument can be made that by displacing petroleum, biofuels reduce the demand for petroleum which in turn reduces the price of the petroleum that is still produced. This lower price can be manifested in a lower price of crude but also in a lower price of finished products such as gasoline and diesel. Consumers have some price elasticity of demand for gasoline and diesel fuel. A lower price for gasoline and diesel would then translate into a marginal increase in demand for gasoline and diesel. Not all the benefits assumed from direct displacement of petroleum by biofuels would be realized due to this “rebound” in petroleum consumption. Such a rebound in petroleum consumption could also be treated as a marginal indirect impact that would reduce the benefits of biofuels. However, it should be noted that any rebound effect that occurs as a result of biofuels use is not unique to biofuels; as the effect would apply to all fuels that reduce the demand for petroleum (e.g. electricity, hydrogen, natural gas, etc.).

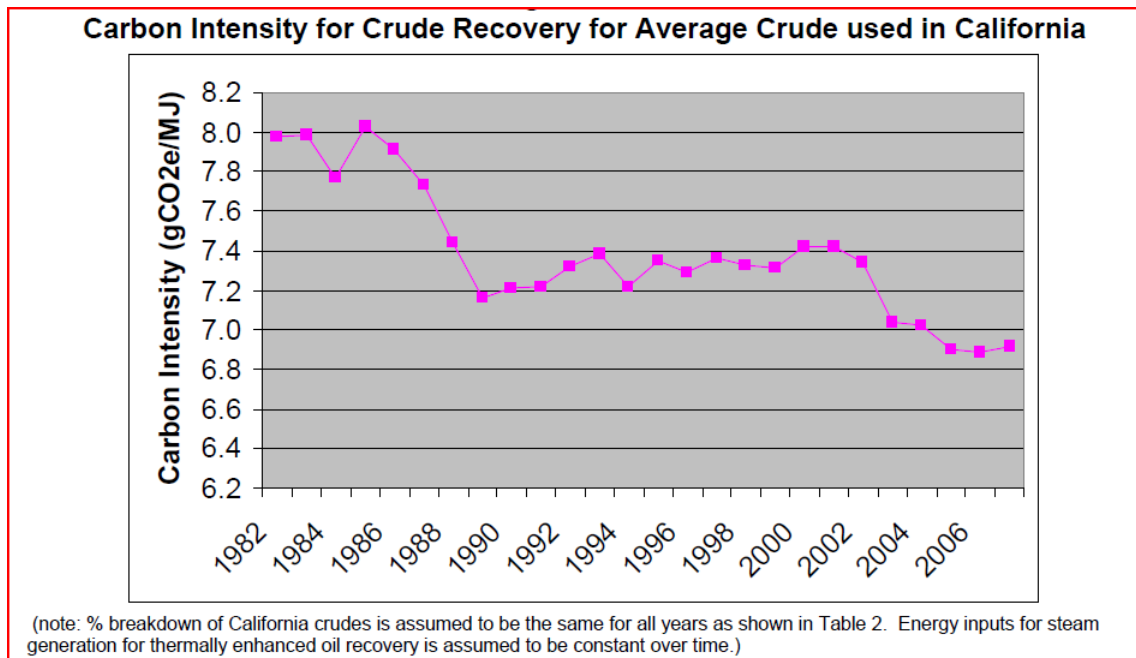
The rebound effect potentially applies to any commodity. If you reduce the demand for something (e.g. gasoline), prices may fall (depending on elasticities) and this may lead to a slight increase in consumption elsewhere as described above. However, this also works in the other direction. If biofuels increase the demand for inorganic fertilizers, fertilizer prices will increase, which means that someone may reduce their use of fertilizers elsewhere in the market. If the rebound effect is considered for gasoline, it should be considered for all commodities across all fuel pathways in order to create a level playing field.

#### **4.1.4 Perspective 1 Conclusion**

The replacement of fossil fuels with biofuels depends on many factors. It is to be expected that biofuels will replace marginal crude oil production in the medium term and in the long term. Whether fossil fuels with the highest greenhouse gas emissions and environmental impact can also be avoided, depends not only on economic decisions but also on the internalization of costs and therefore on political decisions. The biggest environmental benefits that biofuels can provide will only be achieved in cooperation with international climate and environment protection objectives. The opposite is also true: international climate and environmental policy can only be achieved when alternatives to conventional and unconventional oil resources are created. Notwithstanding these considerations, the marginal barrel of oil is directly relevant to how different fuels are scored under the CA LCFS. California should initiate research investigating the marginal barrel of crude oil and its effects vis-à-vis alternative fuel use.

#### 4.2 Perspective 2: The Carbon Intensity of Crude Production and Refining Should be Assessed as an Average in the LCFS

As ARB noted in the staff report for the LCFS, the carbon intensity of the crude mix used in California refineries has been decreasing to fairly stable over the past 20 years which is illustrated in Figure 13. If there is a significant change to that value moving forward, ARB should re-visit that estimate as part of one of the triennial reviews and make appropriate changes.



**Figure 13.** Plot of carbon intensity for average crude in California as a function of time

The timeframe we are considering is very important in assessing this issue. The short-term is 5-10 years in the future, which is the time horizon of the LCFS implementation. Thus, significant changes to the crude slate in the medium- and long-term are very unlikely to be observed in the next 10 years and potentially longer. As such, the LCA conducted for the LCFS should continue to use an average value to represent the carbon intensity of crude.

As an academic exercise, however, there may be some merit in assessing biofuels impacts on the displacement of marginal petroleum production. For the foreseeable future, alternative fuels are expected to displace petroleum growth on a global basis. This is reflected in most forecasts of transportation fuels (e.g., EIA, IEA, etc.).

However, as the analysis of the LCFS needs to consider expected real effects, not theoretical effects. The real questions are:

1. Will the LCFS actually have any real impact on the development of crude production through 2020?
2. If it does have an impact, what production will actually be reduced (i.e., what is the identity of the “marginal” production)?

For the first question, it is unlikely that the California LCFS (which is what we are considering here) will have any significant impact on crude exploration and production activities through 2020. Any petroleum displacement due to the LCFS (and even considering the RFS) will be absorbed by the developing world. Add in that most of the production that will come on line between now and 2020 has already been discovered, and it is unlikely that projects will be cancelled as a result of the LCFS. Volumes that would have an impact are not consistent with the timeframe currently being analyzed for the LCFS (note that the GTAP modeling being used for the iLUC estimates used in the regulations assumes ethanol volumes that are consistent with 2015 to 2020 – much larger volumes that would be consistent with a longer timeframe might produce a different result).

Even if there is an impact within the timeframe of interest, the “marginal” production will not likely be from new fields. That would be inconsistent with historical responses. It would seem to be more likely that the reduction would come from production cuts by some OPEC members in an attempt to stabilize prices. Given the timing and projected biofuel volumes from the LCFS, local stripper wells and the like are more likely to be shut in. This argues that the “marginal” production in the 2015-2020 timeframe looks a lot more like current primary California production or Arab Light than Canadian Oil Sands. As noted by IEA in the “World Energy Outlook 2008” (page 274)<sup>44</sup>:

*Saudi Arabia will continue to play a vital role in balancing the global oil market. Its willingness to make timely investments in oil-production capacity will be a key determinant of future price trends... Saudi Arabia aims to maintain spare capacity in the range of 1.5 mb/d to 2 mb/d in the long term.*

The above logic is consistent with the modeling of the marginal carbon intensity of gasoline and diesel that U.S. EPA prepared for the RFS2 rulemaking. Note that EPA’s modeling showed the marginal barrel in 2022 only increased the well-to-wheels GHG emissions by 0.6%, hence it was considered an insignificant effect. Their analysis indicated that close to 60% of the increase in production would occur in the Middle East and less than 5% of the increase in production would come from oil sands/bitumen.<sup>45</sup>

---

<sup>44</sup> See <http://www.worldenergyoutlook.org/docs/weo2008/WEO2008.pdf>.

<sup>45</sup> See memorandum entitled, “Petroleum Indirect Impacts Analysis,” dated 2/1/10, docket EPA-HQ-OAR-2005-0161.

Section 4.1.1.3 above speculates that OPEC is losing market power, and, by inference, a key assumption in EPA's analysis that most of the marginal crude comes out of OPEC is wrong. It is worth noting that EPA did not "assume" that most marginal crude comes out of OPEC. EPA used the DOE ETP model, followed the EIA AEO-2009 projected oil price path which implies a certain type of rent-seeking behavior by OPEC, and kept that behavior unchanged in the EPA marginal analysis – so EPA was following EIA's modeling of world crude oil markets. EPA's result that most marginal crude came out of OPEC is not an assumption, it is a modeling result. While one can always debate whether or not OPEC is losing market power, it is worth noting that in EIA's AEO-2010<sup>46</sup> and in IEA's "World Energy Outlook 2008" OPEC has a greater share of total world crude oil production in the 2015-2030 timeframe than it does in 2007, not less. Economists normally view growing market share as an indicator of potential *increases* in market power, not decreases. In any case, the timing of any significant change in OPEC's power is inconsistent with that of the current LCFS.

2. Marginal Refining – As with marginal crude, the relevance of marginal refining to the LCFS is unclear. Refiners have to start meeting the LCFS targets in less than three months. Although it is very important to properly account for the energy and material inputs (e.g., natural gas, hydrogen, purchased electricity, etc.) used to process crude, that should be included as a single average carbon intensity for the crude slate run in California.

Other members of the subgroup have postulated that the following chain of events would occur as a result of biofuels production:

- (a) Biofuels will displace gasoline and diesel that would have otherwise been produced.
- (b) The drop in demand of gasoline and diesel will reduce throughput and potentially shut down conversion units (e.g., FCCs, cokers).
- (c) If conversion units are shut down or if throughput is reduced, there will be a drop in the carbon intensity of the gasoline/diesel produced because refining severity is reduced.
- (d) This reduction in the marginal carbon intensity of gasoline/diesel should be assigned to biofuels as an "indirect" credit.

Taking point (d) first, in the Final Regulation Order for the LCFS,<sup>47</sup> Section 95481(a)(28) says:

*"Lifecycle greenhouse gas emissions" means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant*

---

<sup>46</sup> See [http://www.eia.doe.gov/oiaf/ieo/pdf/0484\(2010\).pdf](http://www.eia.doe.gov/oiaf/ieo/pdf/0484(2010).pdf).

<sup>47</sup> See <http://www.arb.ca.gov/regact/2009/lcfs09/lcfscombofinal.pdf>.

*indirect emissions such as significant emissions from land use changes), as determined by the Executive Officer, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer....*

This indicates the full fuel lifecycle is for the finished fuel used by the consumer. A reasonable reading of this is that if the lifecycle GHG emissions of gasoline or diesel change, they change, period. There is nothing in the above language about giving “credit” to any other fuel (gasoline or otherwise) for the change. Thus, if it is argued that an increase in biofuels use results in reductions in the lifecycle GHG emissions of gasoline, there still is no basis for giving biofuels “credit.” Based on the LCFS regulatory language, it seems that the lifecycle emissions of the “finished fuel” are what matter, not what may have caused the lifecycle emissions to change.

That said, a key question that emerged from discussions among the subgroup members is:

*Do refineries stop or significantly reduce cracking or reforming when demand for gasoline drops?*

The primary affect will be refining fewer barrels as biofuel replaces petroleum, offset a bit by the expected reduction in oil price (due to lower demand) being passed along as lower gasoline and diesel prices resulting in a price-induced increase in demand by consumers. A secondary impact will be to use less hydrogen for hydrocracking or hydrotreating as use of H<sub>2</sub> increases marginal cost of product. Impact is dampened somewhat due to high sunk cost refiners have as they invested in hydrocracking / treating technology. For the reduced number of barrels refined, it is likely that refiners will dial in an adjusted slate of products from those reduced barrels. While demand for gasoline and diesel from petroleum will go down, the demand for other products from a refinery will likely be unchanged so it makes sense the refiners that can make an economic adjustment in their product slate will decrease the relative amount of gasoline and diesel in favor of a higher portion of other products. Refinery-specific modeling would be necessary before being able to accurately estimate how much of this adjustment in product slate actually occurs and what impact that might have on the carbon intensity of gasoline and diesel.

Other issues to consider are:

- Refinery modeling is a complicated issue and it is unclear that existing analyses are appropriate for this purpose.
- Yields of various products based on simple distillation are highly dependent on the characteristics of the crude. Light sweet crude might have as much as 70% in

the naphtha/gasoline range, while heavy crude might have very little (see, for example, [http://www.exxonmobil.com/apps/crude\\_oil/index.html](http://www.exxonmobil.com/apps/crude_oil/index.html)). Light crude sells at a premium because the refineries processing that crude do not have to be as complex. On the flip-side, heavy crude sells at a discount because refineries processing heavy crudes have invested in more equipment (e.g., FCCs and cokers) and more hydrogen is generally needed for processing. The variability in crude prices as a function of source (and corresponding API gravity) can be clearly seen in EIA's data available at [http://www.eia.doe.gov/dnav/pet/pet\\_pri\\_wco\\_k\\_w.htm](http://www.eia.doe.gov/dnav/pet/pet_pri_wco_k_w.htm).

- Very few, if any, refineries in the U.S. are “topping” refineries (i.e., distillation only). They cannot compete and they probably could not produce CARB gasoline. Thus, the premise that downstream conversion, FCC, alkylation, coking, and hydrocracking is treatment of co-products appears to be off the mark. These processes are integrated into the refinery designs in the U.S.
- The carbon intensity of gasoline and diesel, marginal or otherwise, is highly dependent on the crude source and refinery design – essentially all gallons of gasoline are chemically converted in some way in U.S. refineries. The refining LCA must account for the extra processing steps but it should only do so as part of a single average refining CI for gasoline produced from a given crude source.
- With the recent change from E0 to E10 in the U.S., feed to conversion units has remained fairly stable with a shift in the boiling range of the products (e.g., a shift in the boiling range of products from gasoline to jet fuel).
- Decreased demand for gasoline will not result in the back-end of refineries shutting down. Instead, there will be rationalization in the industry, i.e., the least sophisticated refineries that run lighter crudes will shut down. This has been observed over the past few years.
- Heavier/cheaper crudes will continue to be run to best utilize the investment in conversion units. If crude runs are cut as a result of increased biofuels demand, light crudes will be cut.
- Refinery configuration is often based on the supply of crudes in a region irrespective of biofuels demand. For example, coking operations have been added to a number of Gulf Coast refineries to process heavy crude that will be coming out of Brazil. This again supports the notion that light crude is the marginal crude rather than heavy crude.

Other refiner responses to increased biofuels demand and decreased gasoline/diesel demand could include a reduction in imports of finished products or an increase in

exports of finished products. In EPA's analysis of the RFS2, it was assumed that gasoline imports into the East Coast (PADD 1) would be reduced as a result of the biofuels mandate.<sup>48</sup> Recent EIA data reported by Reuters indicate that U.S. refiners have begun exporting finished fuels in response to weakened demand for gasoline and diesel in the U.S.<sup>49</sup>

### 4.3 Recommendations

- 1) ARB should initiate a comprehensive analysis of the substitution of fossil fuels with biofuels. The analysis should include all the factors influencing the substitution process in the short- medium and long term (e.g. market power of the OPEC Cartel, correlation between production costs and carbon intensity, predictions of conventional and unconventional fuels)**
- 2) ARB should initiate a comprehensive analysis of the opportunities and limitations of economic modeling to determine the fossil fuel that is replaced with biofuels**

## 5.0 Carbon Intensity and Military Effects

As with ILUC for biofuels, there is an intense debate on the inclusion of military emissions as part of the carbon intensity of certain fossil fuels imported to the United States. The EWG-IE group was unable to reach consensus on this point, and the two different perspectives around this issue are presented.

### 5.1 Perspective 1: Military Emissions should be Included in the LCFS

The U.S. military has been shown to be a vital component in the production and safe passage of certain foreign oil supplies, especially in the Middle East. As is the case with indirect land use change, the issue of military emissions is controversial. Military emissions are uncertain, and occur as a result of many variables. However, there are clear arguments in favor of including military emissions – or a portion of them – in the carbon intensity (CI) value of certain types of crude oil.

<sup>48</sup> "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis," U.S. Environmental Protection Agency, EPA-420-R-10-006, February 2010. <http://www.epa.gov/otaq/renewablefuels/420r10006.pdf>.

<sup>49</sup> "Analysis: As U.S. Petroleum Use Falls, Oil Refiners Look Abroad," Reuters, Joshua Schneyer and Selam Gebrekidan, September 28, 2010. <http://www.reuters.com/article/idUSTRE68R2BC20100928?pageNumber=1>

### 5.1.1. The linkage between military activity and oil is undeniable

Maritime and ground security is critical to the extraction and safe passage of certain crude oil resources.<sup>50</sup> The U.S. military is being used to provide this service for certain foreign oil supplies.<sup>51</sup> While oil is not the only reason for maintaining military presence in the Middle East, government documentation and testimony suggests that oil is the primary reason for military activity in the region.<sup>52</sup> For example, a security strategy document from the U.S. Department of Defense states, “[o]ur paramount national security interest in the Middle East is maintaining the unhindered flow of oil from the Persian Gulf to world markets at stable prices.”<sup>53</sup> A December 2007 GAO report sheds greater light on specific types of activities executed by the U.S. military to protect oil ports and terminals:

In certain locations, the Navy and Coast Guard have also taken more direct action to protect oil terminals—most notably in Iraq. The Navy has set security zones (zones where unauthorized vessels will be fired upon) around Iraqi oil terminals and stationed warships and patrol boats around the terminals. The Navy has also stationed security personnel on the terminal platforms.<sup>54</sup>

A recent, peer-reviewed analysis published in *Environment Magazine* discusses the relevance of military emissions in the context of the carbon Lifecycle Analysis (LCA) methodologies being employed today to quantify the carbon intensity (CI) values of alternative fuels:

Life cycle GHG emissions calculations associated with U.S. gasoline production and use have included emissions from the extraction and shipping of oil as well as combustion, but related military security emissions have been omitted as direct components of the production life cycle. These calculations have been faulty because warships are to oil what combine harvesters are to biofuels. Where combines are mechanical components that use fossil fuels to collect and deliver crops

---

<sup>50</sup> U.S. Government Accountability Office, *Maritime Security: Federal Efforts Needed to Address Challenges in Preventing and Responding to Terrorist Attacks on Energy Commodity Tankers*, GAO-08-141 (Washington, DC: U.S. Government Accountability Office, 2007).

<sup>51</sup> See <http://www.environmentmagazine.org/Archives/Back%20Issues/July-August%202010/securing-foreign-oil-full.html>.

<sup>52</sup> A. Greenspan, *The Age of Turbulence: Adventures in a New World* (New York: The Penguin Press, 2007); U.S. Government Accountability Office, note 6 above, p. 463.

<sup>53</sup> See Crane et al. 2009. *Imported Oil and US National Security*. RAND Corporation, [http://www.rand.org/pubs/monographs/2009/RAND\\_MG838.pdf](http://www.rand.org/pubs/monographs/2009/RAND_MG838.pdf), p. 61.

<sup>54</sup> U.S. Government Accountability Office, *Maritime Security: Federal Efforts Needed to Address Challenges in Preventing and Responding to Terrorist Attacks on Energy Commodity Tankers*, GAO-08-141 (Washington, DC: U.S. Government Accountability Office, 2007), p. 39.



to produce biofuels, the military today is essential for collecting oil from distant regions and delivering it for gasoline production: both are direct supply chain operations that must be included in the LCA of these products. Recent U.S. federal law and government documents make this clear, as does common sense, given the clear security issues associated with maritime oil trade today.<sup>55</sup>

### 5.1.2 The marginal cost of securing foreign oil is real and significant

One way to attempt to measure the GHG intensity of a particular activity is to start with the marginal cost. For example, the 2008 ILUC paper published by Searchinger et al. in *Science* magazine derived their deforestation-GHG estimates from the marginal cost estimates of more corn production calculated by Iowa State economic models. By comparison, there is far more literature covering the marginal cost of U.S. military security for oil than studies covering the marginal cost of using more land. Multiple studies, including several funded by the U.S. government, demonstrate that the marginal cost of protecting foreign oil is real and significant. Table 4 below provides a summary of the estimated (and increasing) marginal costs of military security for Middle Eastern oil over the last thirty years.

**Table 4.** Estimated marginal cost of U.S. military security for Middle East oil: 1980-2010<sup>56</sup>

Study	Publisher	Fiscal yrs	Billion/yr
O'Hanlon, 2010	Brookings Institution	2010	\$50-100
Dancs et al., 2008	National Priorities Project	2009	\$97
Crane et al., 2009	RAND Corporation	2009	\$83

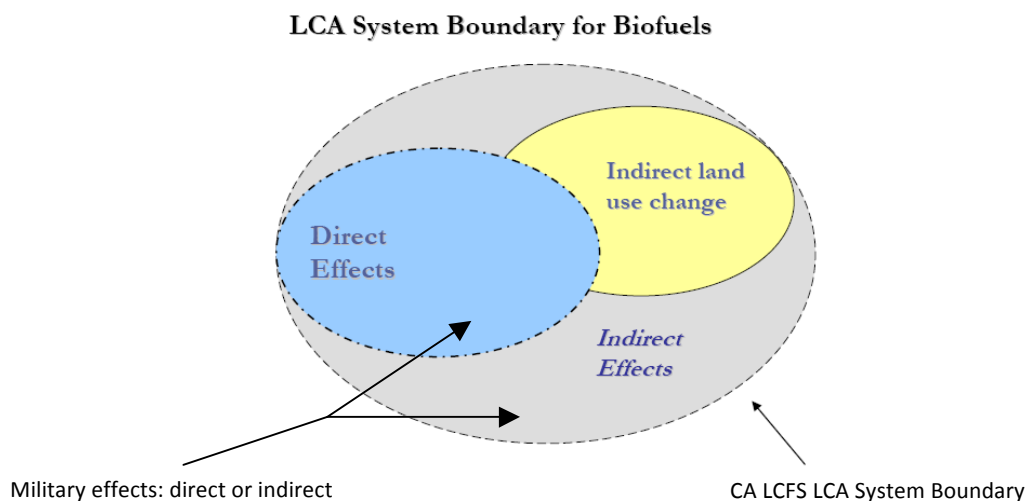
<sup>55</sup> Adam J. Liska and Richard K. Perrin, *Securing Foreign Oil: A Case for Including Military Operations in the Climate Change Impact of Fuels*.

<sup>56</sup> Table compiled by Adam Liska; O'Hanlon, 2010, How much does the United States spend protecting Persian Gulf Oil? IN: Pascual & Elkind 2010, *Energy Security: Economics, Politics, Strategies, and Implications*. Brookings Institution; Dancs et al. 2008. *The Military Cost of Securing Energy*. Natl. Priorities Project. [www.nationalpriorities.org](http://www.nationalpriorities.org); Crane et al. 2009. *Imported Oil and US National Security*. RAND Corporation, [http://www.rand.org/pubs/monographs/2009/RAND\\_MG838.pdf](http://www.rand.org/pubs/monographs/2009/RAND_MG838.pdf); Stern 2010. United States cost of military force projection in the Persian Gulf, 1976-2007, *Energy Policy*, <http://www.princeton.edu/oeme/articles/US-military-cost-of-Persian-Gulf-force-projection.pdf>; Copulos 2007. *The Hidden Costs of Imported Oil: An Update*, <http://www.ndcf.org/>; Duffield 2008 *Over a Barrel: The Costs of U.S. Foreign Oil Dependence*. Stanford Law and Politics; Delucchi & Murphy 2008. U.S. Military Expenditures to Protect the Use of Persian Gulf Oil for Motor Vehicles, *Energy Policy*, [faculty.cbpp.uaa.alaska.edu/jmurphy/papers/DelucchiMurphy2008.PDF](http://faculty.cbpp.uaa.alaska.edu/jmurphy/papers/DelucchiMurphy2008.PDF); Johnson 2004. *The Sorrows of Empire*. Metropolitan Books.

Stern, 2010	<i>Energy Policy</i>	2005-07	\$358
Copulos, 2007	National Defense Council Foundation	2007	\$138
ICTA, 2005	Intl. Center for Technology Assessment	2005	\$39-98.5
	<b>AVERAGE</b>	<b>2005-10</b>	<b>120.4</b>
Delucchi & Murphy, 2008	<i>Energy Policy</i>	2004	\$27-73
Amidon, 2005	<i>Joint Forces Quarterly</i>	1991-04	\$60
Copulos, 2003	National Defense Council Foundation	2003	\$49.1
Duffield, 2008	Stanford University Press	1991-01	\$30-51
Conry & Pena, 2003	Cato Institute	-	\$80
Losman, 2001	<i>Insight Magazine</i>	1990-99	\$30-60
Ravenal, 1996	Cato Institute	1997	\$82
Koplow & Martin, 1998	Greenpeace	1995	\$10.5- 23.3
Fuller & Lesser, 1997	<i>Foreign Affairs</i>	-	\$30-60
GAO, 1996	US General Accounting Office	-	\$65
Delucchi & Murphy, 1996	University of California-Davis	1996	\$20-40
Kaufmann & Steinbruner, 1991	Brookings Institution	1992	\$64.5
Ravenal, 1991	Cato Institute	1992	\$50
GAO, 1991	US General Accounting Office	1990	\$27.3
Greene & Leiby, 1993	Oak Ridge National Laboratory	1990	\$10.8
CRS, 1992	US Congressional Research Service	1990	\$6.4
	<b>AVERAGE</b>	<b>1990-04</b>	<b>\$43.2</b>
Copulos, 1990	<i>Washington Post</i>	1988	\$40
Tunelson & Hurd, 1990	<i>New York Times</i>	-	\$40-45
Rowen & Weyant, 1982	Ballinger	1980-89	\$30-40
	<b>AVERAGE</b>	<b>1980-89</b>	<b>\$39</b>

### 5.1.3: Military Emissions are within the carbon LCA system boundaries of the current LCFS

As discussed in Section 3.0, the final LCFS regulation approved in April 2009 does not commit to one type of carbon LCA. However, the current LCFS utilizes both direct and indirect effects, and CARB staff have committed to including significant indirect effects. As discussed in Liska et al., military emissions could be considered an attributional, direct effect of securing and transporting oil from the Middle East to the United States, or a consequential, market-mediated effect (i.e. a market response) of continuing to rely on Middle Eastern petroleum over time. Neither option would violate the LCA system boundaries currently employed by the CA LCFS (Figure 14).



**Figure 14.** Schematic representation of LCA boundaries of LCFS

#### 5.1.3.1 Option 1: Include military emissions as a direct effect

The logic behind including military emissions as a direct, attributional carbon effect is that the maintenance of the supply chain of certain key oil resources depends on U.S. military security. If this is the case – i.e. that “warships are to oil what combine harvesters are to biofuels” – then military emissions are an omitted direct, attributional effect of producing and using oil. Liska et al. (*Environment*, August 2010) estimate that assigning military emissions to Persian Gulf oil, as a direct effect, would result in a CI value increase of 8.1 CO<sub>2</sub>e-g/MJ (a roughly 8.5 percent increase in the overall CI value of gasoline and diesel fuel derived from Persian Gulf oil under the CA LCFS). As only one of many possible omitted effects for oil, this is a significant increase in the overall CI value for petroleum fuels.

#### 5.1.3.2 Option 2: Quantify military emissions as an indirect effect

As is the case for all indirect, consequential LCA, considering military effects as an indirect effect invites far greater uncertainty and subjectivity into the equation. The logic behind including military emissions as an indirect, consequential carbon effect is consistency: if using a particular fuel results in a real and significant market-mediated response, then it should be included in the CI value of the fuel. The expenditure of military resources, specifically with regard to protecting the maritime oil pipeline, is a response to oil dependence, and an increase or decrease (i.e. a change) in oil dependence could catalyze a response that will have consequences with regard to GHG emissions.

Liska et al. (*Environment*, August 2010) estimate that accounting for military emissions via consequential LCA would result in a CI value increase of 17.5 CO<sub>2</sub>e-g/MJ (a roughly 18 percent increase in the overall CI value of gasoline and diesel fuel derived from Persian Gulf oil under the CA LCFS). This higher bound is in essence an estimate of the carbon benefit of eliminating U.S. dependence on Middle Eastern oil (via less petroleum consumptions and/or more alternative fuel consumption), which in turn would eliminate the need for military expenditures directly related to Persian Gulf oil security.

#### 5.1.3.3 Discussion

While the inclusion of military emissions in the CI value of petroleum is controversial, looking at the issue in an incremental fashion suggests that the inquiry is a valid one. First, the security of oil extraction, production and transit is an explicit and significant part of U.S. foreign policy, force planning and the U.S. defense budget. This commitment results in energy consumption and GHG emissions expressly tied to the supply chain of certain crude oil supplies. Second, there is a significant and measurable marginal cost directly tied to the security of oil extraction, production and transit that can be used as the basis for measuring the estimated GHG effect from oil security similar to the methodologies first used to estimate indirect land use change. Peer-reviewed, published literature suggests that the effect is significant. Third, military emissions are well within the carbon LCA system boundaries utilized by the current CA LCFS, and may even be a direct, attributional effect of producing and using certain types of crude oil.

The primary arguments against including military emissions are:

***The attribution of military activity to oil is uncertain.*** This no longer appears to be true, as the body of evidence suggests a clear connection between oil and military activity (see sections 5.1.1 and 5.1.2 above). In many cases, the connection between oil and military resources is explicit, including but not limited to government documents committing to protecting the safe loading and passage of oil and oil-specific activities such as the creation of safe zones around terminals and maritime security.

***The quantification of military emissions is highly uncertain.*** This is generally true, but the confidence intervals for military emissions do not exceed those for other

factors included in the CA LCFS. For example, in their 2010 assessment of military emissions, Liska et al. state, “[w]e note that this 18 g CO<sub>2</sub>e per MJ of gasoline energy from military security is roughly equivalent to the 14 to 27 g CO<sub>2</sub>e per MJ currently attributed to corn ethanol energy due to consequential indirect land use change. We further suggest that the confidence interval around our estimate is comparable to the confidence interval on the latter figures.”<sup>57</sup> CARB did not publish a formal uncertainty analysis for its ILUC estimates with the LCFS Final Rule.

***The effect should not be included in the carbon LCA because eliminating oil would not significantly change the U.S. military commitment to the Middle East (or other regions).*** This may not be a valid rationale for omitting military effects for primarily two reasons: (1) there is recent analysis suggesting otherwise; and, (2) this is not a threshold issue for other indirect effects.

- (1) There is recent analysis showing that eliminating dependence on Middle Eastern oil, for example, would result in a draw down of military forces in the region. For example, a 2009 analysis conducted by RAND corporation concluded that “the most likely outcome of the removal of the mission to defend oil supplies and sea lines of communication from the Persian Gulf would be a reduction over time of between 12 and 15 percent of the current U.S. defense budget.”<sup>58</sup> Liska et al. make the case for a 20 percent reduction in military activities as a result of eliminating U.S. dependence on Middle Eastern oil, and point out the plausibility of this scenario by noting that “[p]roduction of 57 billion liters per year (bly) of ethanol from corn, as mandated by EISA legislation, would be approximately sufficient to substitute for the 61 bly of gasoline from Middle East oil imports averaged from 2005 to 2009.”<sup>59</sup>
- (2) Even if one assumed that eliminating U.S. dependence on Middle Eastern oil would not appreciably change military behavior because other variables would sustain U.S. military presence in the region, this should not be seen as a reason to exclude military emissions in the CA LCFS because this is not a threshold test applied to other indirect effects. For example, the GTAP model predicts that increasing the demand for corn will drive land conversion overseas. CARB’s decision to include this modeled effect for biofuel did not hinge on any sort of demonstration that without corn ethanol, this land conversion would not occur. Like

---

<sup>57</sup> Adam J. Liska and Richard K. Perrin, *Securing Foreign Oil: A Case for Including Military Operations in the Climate Change Impact of Fuels*, Environment Magazine, p. 19. See <http://www.environmentmagazine.org/Archives/Back%20Issues/July-August%202010/securing-foreign-oil-full.html> at note 54.

<sup>58</sup> See Crane et al. 2009. *Imported Oil and US National Security*. RAND Corporation, [http://www.rand.org/pubs/monographs/2009/RAND\\_MG838.pdf](http://www.rand.org/pubs/monographs/2009/RAND_MG838.pdf), p. 74.

<sup>59</sup> See <http://www.environmentmagazine.org/Archives/Back%20Issues/July-August%202010/securing-foreign-oil-full.html>.

war, “[a]t the underlying level, tropical deforestation is ... best explained by multiple factors and drivers acting synergistically rather than by single-factor causation, with more than one-third of the cases being driven by the full interplay of economic, institutional, technological, cultural and demographic variables.”<sup>60</sup> As such, any number of these variables could replace corn ethanol as a driver of land conversion. Examples include land or energy policy changes in the host country or elsewhere, or market conditions in the U.S. (e.g. eliminating corn ethanol would drive corn prices down, which in turn would catalyze new business designed to use cheap corn, such as corn syrup or feed). The notion that there may be another reason for the U.S. military to stay in the Middle East is no different than concluding that tropical lands will be converted for other reasons in the absence of corn ethanol. If the possible substitution of causal drivers is considered for military emissions, they must be considered for ILUC.

There is also the issue of allocation. Allocating U.S. military emissions to Middle Eastern oil shipped to the United States will produce a larger measure in terms of gCO<sub>2</sub>e/MJ than allocating U.S. military emissions to all oil shipped worldwide from the Middle East. The primary argument for worldwide allocation is that the U.S. military protects Middle Eastern crude oil that ends up in other countries. The primary argument for U.S. allocation is the U.S. is the actor when it comes to military protection for oil in the region, and as such, is the source of the emissions. There is no right answer to the allocation problem, but it is instructive to note that:

- (1) Allocation is a huge factor in the LCFS. Allocation decisions fundamentally change the CI values of all fuels under consideration for the CA LCFS. For example, allocating the GHG emissions from coal-firing to just those biorefineries that use coal produces a high CI value for that individual pathway, whereas allocating coal emissions to all U.S. ethanol produces a much lower overall CI increase. CARB chose to create an individual pathway for coal-fired Midwest ethanol, but has not created individual pathways for oil.
- (2) There are major allocation questions about the current ILUC penalties. Notwithstanding the fact that overseas land conversion occurs as a result of multiple variables acting synergistically, the CA LCFS ascribes all or nearly all of the effect to one variable (increased biofuel demand). More specifically, biofuels pay indirectly for land conversion that occurs as the

---

<sup>60</sup> Helmut J Geist and Eric F Lambin, *Proximate causes and underlying driving forces of tropical deforestation*, Bioscience; Feb 2002; 52, 2, p. 145; see <http://www.puce.edu.ec/zoologia/vertebrados/personal/sburneo/cursos/EcologiaII/Bibliografia/2-5%20Deforestacion%20tropical.pdf>

direct result of food and feed production (with the rationale that biofuels caused these entities to clear new land). While it might seem reasonable to ascribe military emissions to all Persian Gulf exports based on a theory of “real-world allocation,” this is not the methodology used to ascribe ILUC penalties today.

Irrespective of the approach taken, CARB should be as consistent as possible across all fuel pathways.

## **5.2 Perspective 2: Military Emissions should not be included in the LCFS**

U.S. EPA considered this issue in the development of the Renewable Fuel Standard (RFS2) rulemaking that implemented the 2007 Energy Independence and Security Act. As part of the “Renewable Fuel Standard Program (RFS2) Summary and Analysis of Comments” document prepared by EPA (page 7-248),<sup>61</sup> there is a good summary of EPA’s position on this issue:

*We also do not believe that emissions arising from military activities can be readily attributed to the protection of oil imports. Military activities, even in world regions that represent vital sources of oil imports, undoubtedly serve a broader range of security and foreign policy objectives than merely protecting oil supplies. In the peer review of the energy security analysis that EPA commissioned, a majority of peer reviewers believed that U.S. military costs should be excluded absent a widely agreed methodology for estimating this component of U.S. energy security. Since military impacts were not considered for the energy security analysis in this final rule, they were also excluded from any lifecycle GHG analyses*

*Furthermore, increased domestic consumption of renewable fuels is expected to decrease oil demand and thus reduce oil imports. However, an incremental reduction in oil imports is not expected to cause an analogous reduction in U.S. military expenditures and activities. Hence, even if we were able to attribute GHG emissions to the protection of oil imports, it is unlikely that there would be a decrease in military-related GHG emissions as a result of this rule.*

EPA goes on to say (on page 7-342):

*As stated in the proposal and restated in the preamble to the final rule, EPA has not included in its assessment of GHG impacts of petroleum the*

---

<sup>61</sup> See <http://www.epa.gov/oms/renewablefuels/420r10003.pdf>.

*potential impacts due to military operations to protect sources of petroleum. While these potential military impacts have been estimated by some researchers, there is clearly no consensus on how much if any of the GHG emissions from military operations should be attributed to an assessment of petroleum's GHG lifecycle impact. Do the the (sic) widely speculative nature of such an assessment, EPA chose to leave it out of our GHG assessment.*

As part of its comments on the RFS2 rulemaking, the American Petroleum Institute (API) supported EPA's decision to exclude these types of indirect effects as insignificant and speculative.<sup>62</sup> API also cited a report prepared by Jeff Kueter of the George C. Marshall Institute<sup>63</sup> that supported many of the arguments put forth by EPA. Finally, API noted that:

*...there is no reason to think that world tensions over energy sourcing will abate by a shift from one type of fuel to another. As the fraction of renewables increases in the world's transportation fuel supply, the political burden will shift proportionately. Thus, logic would have it that any carbon intensity debit placed on petroleum fuels as a result of energy sourcing tensions should be placed equally on all fuels.*

In any case, if military impacts for fuel protection were to be included for Middle East oil, similar considerations would have to be made for biofuels moving forward (e.g., ethanol shipments from Brazil).

A recent report prepared by the National Research Council also considered the issue of military protection of crude supply ("The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use"<sup>64</sup>) and found the following:

*Dependence on imported oil has well-recognized implications for foreign policy, and although we find that some of the effects can be viewed as external costs, it is currently impossible to quantify them. For example, the role of the military in safeguarding foreign supplies of oil is often identified as a relevant factor. However, the energy-related reasons for a military presence in certain areas of the world cannot readily be disentangled from the nonenergy-related reasons. Moreover, much of the military cost is likely to be fixed in nature. For example, even a 20% reduction in oil consumption, we believe, would probably have little*

---

<sup>62</sup> See Document No. 2393.1 of Docket ID No. EPA-HQ-OAR-2005-0161 dated September 25, 2009.

<sup>63</sup> "National Security, Energy Security, and a Low Carbon Fuel Standard," Jeff Kueter, George C. Marshall Institute, 2009. <http://www.marshall.org/pdf/materials/643.pdf>

<sup>64</sup> "The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use," Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption, National Research Council, 2010. [http://www.nap.edu/catalog.php?record\\_id=12794](http://www.nap.edu/catalog.php?record_id=12794)



*impact on the strategic positioning of U.S. military forces throughout the world.*

### **5.2.1 Perspective 2 Conclusion**

In summary, a credible GHG estimate of military protection of crude supply is not possible at this time. There are too many uncertainties, and any allocation to crude protection would be, as EPA notes, widely speculative. In addition, it must be recognized that as alternative fuels scale up, there will be accidents and political conflicts associated with their life cycles. Political response always has and always will exist where energy is concerned. Thus, if a debit is ultimately assigned to petroleum fuels, the same would be needed for all others recognizing that as they grow in volume, their vulnerability to the same kind of problems will increase.

Finally, as with worldwide crude oil shifts in response to CA LCFS-driven biofuel production discussed above, the impact of the LCFS is unlikely to be reflected in military expenditures over the life of the program. Even the worldwide economic downturn has had no discernable short-term effect.

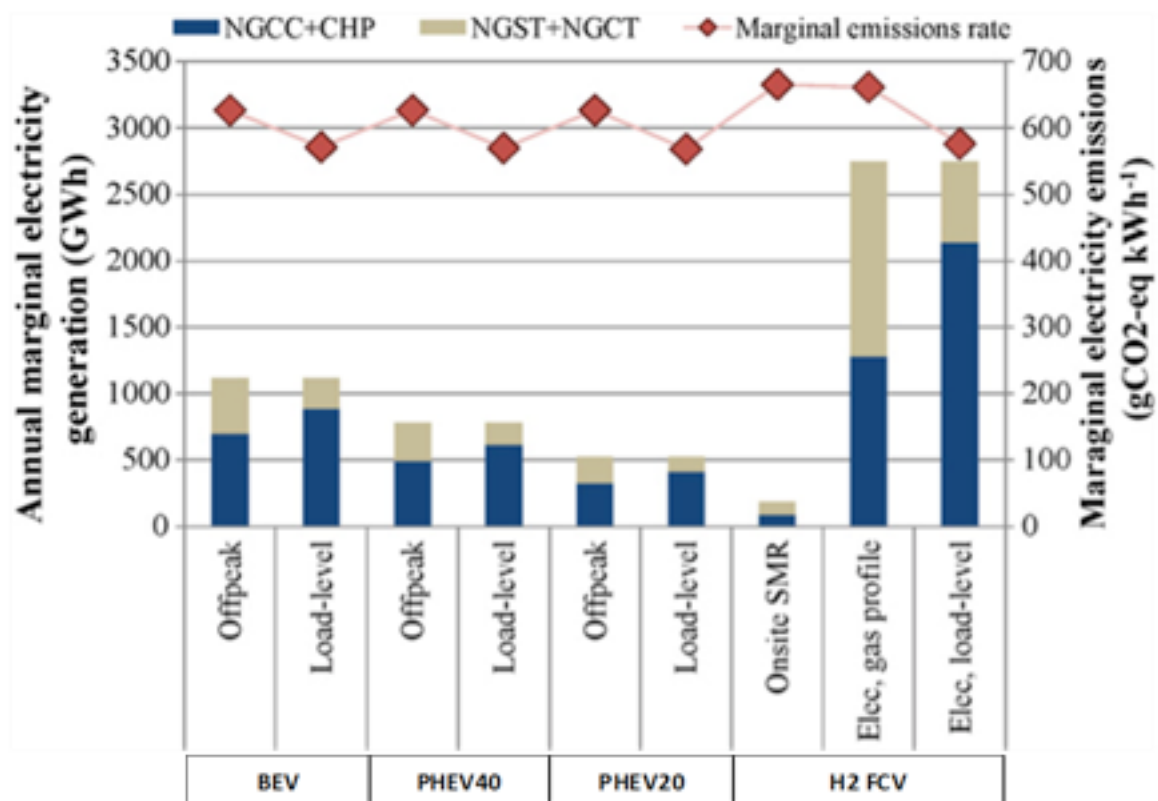
## **6.0 Indirect Effects: Electric and Hydrogen Vehicles and Marginal Electricity Effects**

### **6.1 Marginal Electricity as a Potentially Significant Source of Emissions**

The impact of energy production is a critically important factor to take into consideration when evaluating the marginal effects of fluctuating demand. The logical starting point for any analysis of the “marginal resource effect” of electricity and hydrogen is the margin of the electric power sector. This is the case because the increased use of these fuels will increase demand for electricity from plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs), and fuel cell vehicles (FCVs), which in turn will drive existing electric power production to new resources along the margin of the system. Over the long-term, typical approaches taken by scientists in this field are to make assumptions in the type of installed power plant (typically newer, more efficient installations) that produces the electricity and assume that the marginal demand will be met by this new installed power plant capacity. What is missed by this approach is that over the short- and medium-term any increase in demand, such as that presented by an increase in the number of electric vehicle on the road, will have to be met on the margin by current power plants that are less efficient and emit more pollution.<sup>65</sup> This temporal effect has sparked a series of perspectives in the scientific literature and debates in terms of what type of power plant should be included as the supplier of marginal electricity.

---

<sup>65</sup> Lund, H.; Mathiesen, B.V.; Christensen, P.; Schmidt, J.H. *Int J Life Cycle Assess* (2010) 15:260-271



**Figure 15.** Marginal electricity generation and direct GHG emissions rates by vehicles and fuel pathway (Taken and adapted from McCarthy et al, *Journal of Power Sources*, 2010).

Three types of vehicles that rely on electricity are included in the LCFS: (1) battery-electric vehicle (BEV), (2) plug-in hybrid electric vehicle (PHEV), and (3) hydrogen fuel cell vehicle (FCV).<sup>66</sup> For the PHEV, well-to-tank emissions are significant and must be taken into account, including the supply of electricity to the vehicle during charging. For the FCV and BEV the only emissions are those associated with upstream electricity production. The analysis and assessment of the emissions associated with electricity production need detailed analysis in order to establish the appropriate marginal effects as a function of an increasing number of these vehicles entering the marketplace.

The dynamics in electricity demand impact the supply from one hour to another. In the United States, the baseline electricity supply is currently met by large coal or nuclear power plants and are designed to generate power on a continuous basis and at very low cost. The peak demand power plant is often fueled with natural gas and operated on an

<sup>66</sup> Note that hydrogen produced via electrolysis of water will require a significant amount of electricity, however, it is unlikely that hydrogen produced from that pathway will be economically viable in the short-term compared to hydrogen production from natural gas via steam methane reforming (SMR). Electricity is also required for the SMR pathway for compression for on-board storage and if the hydrogen is liquefied for bulk transport.

infrequent basis to meet the sudden increases in power demand. In between the baseline and peak levels there are a myriad range of power plants in operation to meet the transient changes in expected load. A further complication is that this mix of power plants is highly dependent on the region of the world under scrutiny.

Economics dictate that whenever and wherever possible, the electricity demand is met by the lowest cost option available. The import/export of electricity from one state to another is an option frequently utilized over the grid in the United States to drive costs down and ensure that the demand is being met. The addition of battery charging and/or hydrogen production is an added drain to the grid, and the impact of this increased demand in terms of the installations available to meet it. The current LCFS assumes that marginal electricity is provided by NGCC plants (79%) and renewable power (21%), with GHG emissions of 377 g CO<sub>2</sub>eq/kWh, or 104.7 gCO<sub>2</sub>eq/MJ.<sup>67</sup>

In a CEC funded study, McCarthy et al. utilized a model (denoted as EDGE-CA) to evaluate the current composition and mix of electricity power generation in CA to determine the short- and mid-term impact of advanced engine deployment and its impact on the marginal electricity demand.<sup>68</sup> The results from this study produced CI numbers (see Figure 15) much higher compared to those currently included in the CA LCFS. The results presented in this study are based on assumptions regarding median hydro-availability (about 35,000GWh annually) and geographical distribution of marginal demand (in proportion to non-vehicle electricity demand: 42% in CA-N, 49% in CA-S, and 9% in LADWP). The following section is a direct excerpt from the paper:

“Generation from NGCC and natural gas combined heat and power (CHP) plants are combined in the figure because both tend to operate with relatively high capacity factors and similar GHG emissions rates. Generation from NGST and NGCT plants is also combined, as both plant types have GHG emissions rates that are about 50% higher than NGCC or CHP plants. A small amount of marginal generation comes from other plant types (much less than 1%), but is not shown for clarity. The associated GHG emissions rate from marginal generation is given as well, on the right axis. The fraction of generation from NGST and NGCT plants and the marginal electricity GHG emissions rate decreases as demand shifts to off-peak hours.

For the load-level profile, where all demand occurs off-peak, about 21% of marginal generation comes from NGST or NGCT plants and marginal electricity GHG emissions rates are about 570 gCO<sub>2</sub> equiv.kWh<sup>-1</sup>. The Offpeak profile spreads recharging demand throughout the day, though still predominantly at night. In scenarios with that recharging profile, 37% of generation comes from NGST or NGCT plants and marginal emissions are about 625 gCO<sub>2</sub> equiv.kWh<sup>-1</sup>. The majority of demand occurs during the day in the gasoline profile, and NGST

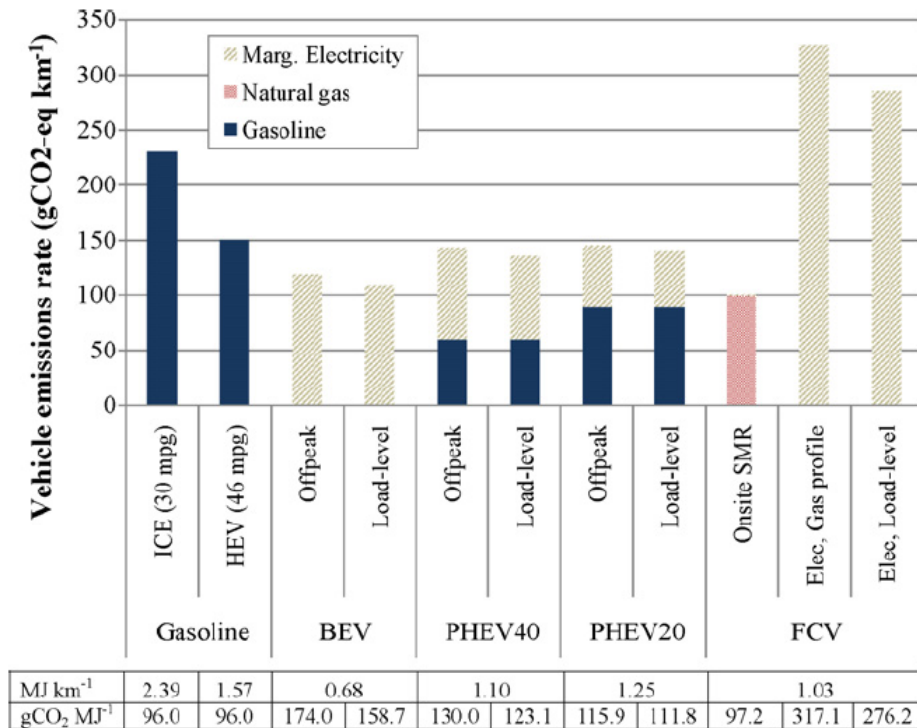
---

<sup>67</sup> ARB, GREET Pathway for California Average and Marginal Electricity (Version 2.1), CARB, 2009.

<sup>68</sup> McCarthy, R.; Yang, C. J. *Power Sources* (2010) 195:2099-2109

and NGCT plants supply more than 50% of marginal demand for hydrogen supply. As a result, marginal GHG emissions rates are relatively high, about 660 gCO<sub>2</sub> equiv.kWh<sup>-1</sup>.

Based upon these assumptions, the carbon intensity of marginal electricity is 65–90% higher than that of gasoline. If this marginal electricity were used as fuel, electric-drive vehicles would need to be that much more efficient than a comparable gasoline vehicle to offer GHG emissions reductions in California.”



**Figure 16.** Well-to-wheels vehicle emissions (gCO<sub>2</sub> equiv.km<sup>-1</sup>) by energy source, vehicle energy intensity (MJkm<sup>-1</sup>), and fuel carbon intensity (gCO<sub>2</sub> equiv. MJ<sup>-1</sup>) by pathway and timing profile.

As stated in the McCarthy et al., these results are in stark contrast to the current values attributed to marginal electricity for the short- and long-term in the LCFS: “[t]he [LCFS] assumes that marginal electricity comes from NGCC plants (79%) and renewable power (21%), with a GHG emissions rate of 104.7 gCO<sub>2</sub> equiv. MJ<sup>-1</sup> ... [b]ut in the near-term, the likely marginal mix and GHG emissions rate will be quite different. Renewable power does not operate on the margin and marginal generation from dispatchable power plants is unlikely to come entirely from NGCC plants operating with average heat rates ... the results here suggest that the marginal generation mix will be about 63% from NGCC

*plants and about 37% from NGCT plants, and marginal emissions rates will be more than 65% higher than in the LCFS.”<sup>69</sup>*

Although the McCarthy et al. analysis is useful for understanding how the electric grid in California might be impacted by electric vehicles, a number of assumptions were made that could lead to uncertainties in the results:

1. This was a modeling exercise in which 220,000 BEVs, PHEVs, or FCVs were instantaneously placed into the 2010 California fleet and electric grid with no warning. The ramp-up of these advanced technology vehicles to these levels will take a number of years, and the magnitude and time period of the model shock should be considered carefully.
2. Hydrogen production from electrolysis in the 2010 timeframe does not seem plausible. Steam methane reforming is much more likely unless there is a very inexpensive source of electricity. The relevance of this particular scenario is unclear.
3. The authors state the limitations of their modeling in Section 3.1 of their paper. In particular, they note that the EDGS-CA model may misrepresent the exact mix of individual power plants operating at a given time, but it does accurately capture the types of power plants operating in the state and therefore is a useful framework for analyzing the California grid.

When applied to different vehicle use scenarios, the analysis shows that consideration of the “marginal resource effect” could fundamentally change the CI profile of certain alternatives. We therefore **recommend** that ARB re-evaluate these values in light of this report and consider the funding of a more comprehensive study to verify these results.

## **6.2 Rare Earth, Lithium and Upstream Resource Depletion**

Indirect land use change is considered an important issue in the context of the LCFS because biofuel production depends on land, and the world’s land resources are constrained and finite. Likewise, the production of electric vehicles (or the use of electricity for fuel) depends on lithium and/or other “rare earth” materials and other materials for battery production (e.g. nickel, etc.), on-board electricity storage, and electric motors. A recent analysis by Gerson Lehrman Group estimates that producing 500,000 electric cars – or the equivalent of just under 1% of all autos produced worldwide today – would require roughly 10 percent of total worldwide lithium production.<sup>70</sup> This is relevant to the LCFS for several reasons: (1) upstream metal mining

---

<sup>69</sup> See [http://pubs.its.ucdavis.edu/download\\_pdf.php?id=1362](http://pubs.its.ucdavis.edu/download_pdf.php?id=1362).

<sup>70</sup> See <http://www.glgroup.com/News/Nissan-breaks-silence-on-lithium-consumption-42764.html>.

for electric batteries and electric motor components is not currently included as part of the electricity carbon score in the LCFS;<sup>71</sup> (2) there is a potential resource depletion issue, as other products and uses rely on lithium, rare earth metals, and heavy metals for the production of goods and services. With regard to the first issue, there are potentially large environmental impacts, including carbon emissions, which may be relevant to the electricity CI value.<sup>72</sup> With regard to the second issue (resource depletion), while there is no consensus on how much lithium will be available to facilitate the use of electricity as fuel, some studies suggest that the resource is highly constrained.<sup>73</sup> As is the case with land use, there is a risk that increasing the demand for lithium and/or rare earth/heavy metals for battery and electric motor production<sup>74</sup> could have direct effects (in the form of emissions from metal mining and processing) and indirect effects (in the form of pushing existing industries reliant on lithium and heavy metals for batteries and other products to the resource margin).

The EWG-IE is not aware of any research investigating the potential market-mediated effects of increased lithium and heavy metal demand, but there are a few studies that have looked at the direct upstream impacts of battery production. The small number of studies in this category suggests that the greenhouse gas emissions associated with lithium or heavy metal (e.g. nickel) battery production account for 2-10 percent of the lifecycle emissions of PHEVs; however, it should be noted that these studies do not account for any market-mediated effects, including land impacts, however large or small.<sup>75</sup> In sum, the increased use of lithium and heavy metals to facilitate electricity use as a transportation fuel could have significant direct and indirect effects. At minimum, ARB should initiate a preliminary scoping analysis of the potential direct and indirect effects of upstream heavy metal mining and processing. The analysis should take into account, among other things, considerations relative to allocation (i.e. vehicles are not and would not be the only driver of lithium, rare earth, and heavy metal mining).<sup>76</sup> If potentially significant effects are identified, ARB should conduct a more rigorous analysis prioritizing the issues identified in the scoping analysis.

---

<sup>71</sup> See [http://www.arb.ca.gov/fuels/lcfs/022709lcfs\\_elec.pdf](http://www.arb.ca.gov/fuels/lcfs/022709lcfs_elec.pdf).

<sup>72</sup> See [http://www.pbs.org/newshour/bb/asia/july-dec09/china\\_12-14.html](http://www.pbs.org/newshour/bb/asia/july-dec09/china_12-14.html); see also [http://www.meridian-int-res.com/Projects/Lithium\\_Microscope.pdf](http://www.meridian-int-res.com/Projects/Lithium_Microscope.pdf).

<sup>73</sup> See [http://www.meridian-int-res.com/Projects/Lithium\\_Microscope.pdf](http://www.meridian-int-res.com/Projects/Lithium_Microscope.pdf); for a counter view, see [http://www.che.ncsu.edu/ILEET/phevs/lithium-availability/An\\_Abundance\\_of\\_Lithium.pdf](http://www.che.ncsu.edu/ILEET/phevs/lithium-availability/An_Abundance_of_Lithium.pdf).

<sup>74</sup> European Commission 2010. Critical raw materials for the EU Report of the Ad-hoc Working Group on defining critical raw materials. [http://ec.europa.eu/enterprise/policies/rawmaterials/documents/index\\_en.htm](http://ec.europa.eu/enterprise/policies/rawmaterials/documents/index_en.htm)

<sup>75</sup> See Constantine Samaras and Kyle Meisterling, "Life Cycle Assessment of Greenhouse Gas Emissions from Plug-in Hybrid Vehicles: Implications for Policy," *Environ. Sci. Technol.*, 2008, 42 (9), 3170-3176; also, Notter et al., "Contribution of Li-Ion Batteries to the Environmental Impact of Electric Vehicles," at <http://pubs.acs.org/doi/abs/10.1021/es903729a>.

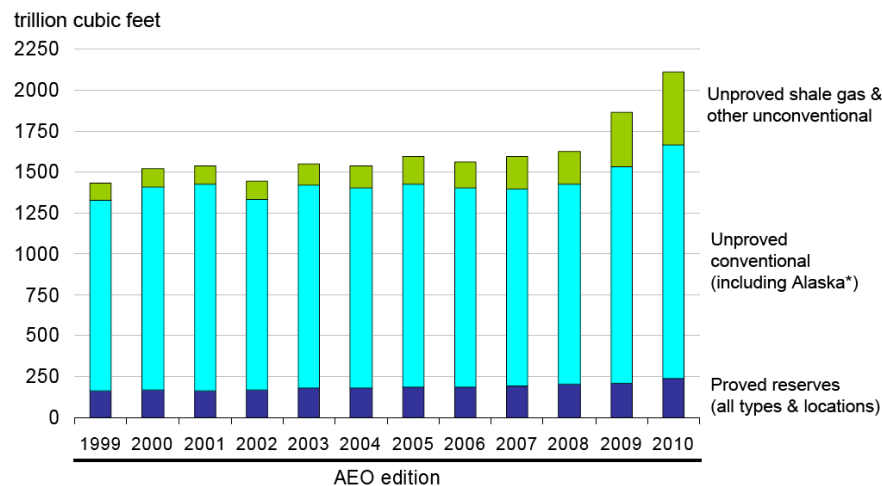
<sup>76</sup> See <http://minerals.usgs.gov/minerals/pubs/commodity/lithium/lithimcs06.pdf>.

## 7.0 Marginal Impacts and Indirect Effects of Natural Gas

The LCFS Lookup Table includes four individual fuel pathways for Compressed Natural Gas (CNG) and nine individual fuel pathways for Liquefied Natural Gas (LNG).<sup>77</sup> None of the thirteen total “natural gas” fuel pathways are debited for indirect effects.<sup>78</sup> As is the case for other fuels, the logical starting point for any analysis of the possible indirect effects of natural gas is along the margin of the primary resource being utilized to produce the fuel. In the case of the natural gas, there are two logical places to start:

### 7.1 The margins of the natural gas resource itself

As discussed in the context of petroleum, the use of a given unit of a finite and exhaustible resource accelerates the depletion of this resource and drives other users to the resource margin. Using more natural gas for transportation could have GHG impacts along the margin of the natural gas resource, by driving new growth into new resources. As is the case for petroleum, there are trends within the natural gas industry itself that are relevant to its carbon LCA. For example, it is expected that an increasing share of domestically-produced natural gas will come from marginal/stripper wells.<sup>79</sup> In addition, shale gas has been the primary source of recent growth in U.S. technically recoverable natural gas resources (see Figure 17 below).



\* Alaska resource estimates prior to AEO2009 reflect resources from the North Slope that were not included in previously published documentation.

Source: EIA, Annual Energy Outlook 2010.<sup>80</sup>

**Figure 17.** Recent Growth in U.S. Technically Recoverable Natural Gas Resources

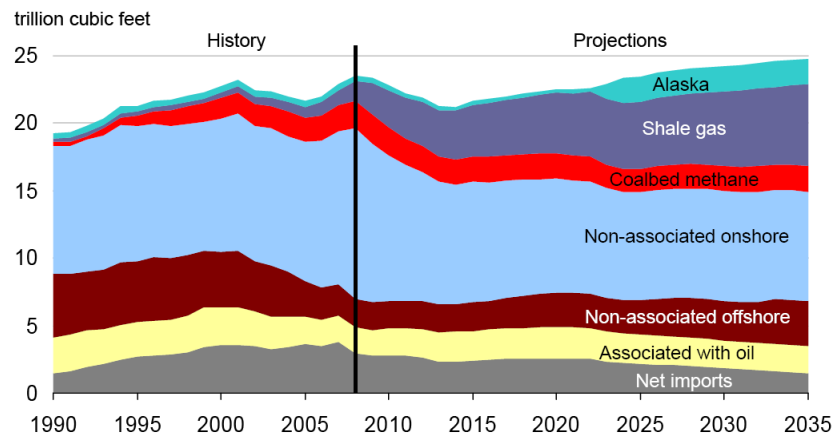
<sup>77</sup> See [http://www.arb.ca.gov/fuels/lcfs/121409lcfs\\_lutables.pdf](http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf).

<sup>78</sup> In other words, all of the natural gas pathways are assigned “0” in the “Land Use or Other Indirect Effect” column.

<sup>79</sup> See [http://www.netl.doe.gov/technologies/oil-gas/publications/AP/MarginalWells\\_AP-DOE.pdf](http://www.netl.doe.gov/technologies/oil-gas/publications/AP/MarginalWells_AP-DOE.pdf).

<sup>80</sup> See <http://www.eia.doe.gov/neic/speeches/newell121409.pdf>, slide 16.

As shown in Figure 18 below, shale gas is expected to account for an increasing percentage of overall natural gas production over time, and according to EIA, represents the single largest source of growth in U.S. natural gas supply (i.e. along the margin of natural gas energy markets needed as part of increasing demand over time).<sup>81</sup>



Source: EIA, Annual Energy Outlook 2010.<sup>82</sup>

**Figure 18.** Recent Growth in U.S. Technically Recoverable Natural Gas Resources

It is important to recognize that shale gas is not the only natural gas supply on the margin of the marketplace. However, given that shale gas represents a rapidly increasing fraction of U.S. natural gas supply, and an even greater percentage of the new (marginal) growth of natural gas coming online in recent and future years, more rigorous analysis of the natural gas margin should be the subject of further analysis.

## 7.2 Shale Gas Resources: Rapidly Changing Resource Considerations

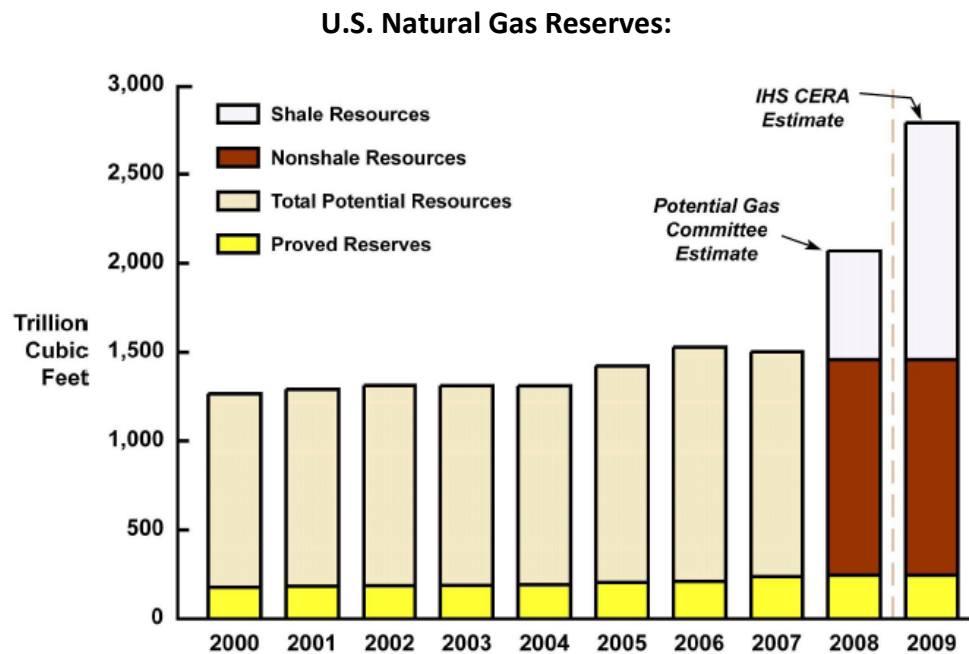
The role of unconventional natural gas resources such as shale gas as part of the NG resource base in the United States has shifted dramatically over the last decade. Only 5-8 years ago, shale gas represented 1% of national gas volumes, and now in a very short period of time, it is reported to be up to at least 20%. Peter Stark of IHS CERA has formally speculated that by the year 2035, up to 50% of the nation's gas supply will

<sup>81</sup> <http://www.eia.doe.gov/oiaf/aeo/gas.html>

<sup>82</sup> See <http://www.eia.doe.gov/neic/speeches/newell121409.pdf>, slide 17.



derive from Shale, following recent trends in the nation's reserves of natural gas as highlighted in the figure below.<sup>83,84</sup>



**Figure 19.** Recent Trends in U.S. Natural Gas Reserves<sup>83</sup>

According to Mr. Stark and IHS CERA, one half of U.S. natural gas is currently supplied by wells drilled in the past 40 months.<sup>85</sup> The growth in shale natural gas has occurred more quickly than any other comparable change in underlying energy feed stocks. In roughly half as much as time as the 10-fold growth in the ethanol market volume (i.e., 1 to 10 billion gallons), shale gas as a percentage of total U.S. gas supply has already achieved nearly three times as large a respective market share. The pace and scope of the growth of shale gas resources, as well as its possible water resource implications, is outlined in a recent analysis undertaken by the University of Toronto's Munk Centre.<sup>86</sup> This rapid change in the underlying characteristics of the nation's natural gas supply may

<sup>83</sup> "The Shale Gale: Its About Gas And Oil," Peter Stark, IHS CERA, NAPE Conference, Aug. 18, 2010, <http://napeexpo.com/files/Pete%20Stark.pdf> ; "

<sup>84</sup> Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda," Executive Summary, An IHS CERA Special Report, March 10, 2010, p. 1, "Shale gas accounted for only 1 percent of US natural gas supply in 2000; today it is 20 percent. By 2035 it could be 50 percent." [http://press.ihc.com/article\\_display.cfm?article\\_id=4211](http://press.ihc.com/article_display.cfm?article_id=4211) ; [http://www2.cera.com/docs/Executive\\_Summary.pdf](http://www2.cera.com/docs/Executive_Summary.pdf)

<sup>85</sup> Perspectives on the Unconventional Revolution in North American Natural Gas, Steve Trammel, Sr, Product Manager, Pete Stark, VP, Industry Relations, and Curtis Smith, CERA, slide #8, [http://docs.google.com/viewer?a=v&q=cache:hQ3ZgNPTFOqJ:www.iogcc.state.ok.us/Websites/iogcc/Images/Biloxi2009/IOGCC%2520Uconv%2520Gas%252010\\_09%2520Handout.pdf+%22pete+stark+2010+shale+gas+ppt%22&hl=en&gl=us&pid=bl&srcid=ADGEEShSbRdYby2vOy1Na8tWuVSGubxQ3BsJrO-j7ZnHet-nMKFWuw-vZ48bRgX-V5X6oKXvq4FM57yzCqy48ACyITxoZKufL2eRrjvMhix2BFtkJPAsT9EKrGJncEwiz8c7vQ88Pt2-&sig=AHIEtbReSD4G5dFubJRZG\\_GH5YDiZ-ZxTw](http://docs.google.com/viewer?a=v&q=cache:hQ3ZgNPTFOqJ:www.iogcc.state.ok.us/Websites/iogcc/Images/Biloxi2009/IOGCC%2520Uconv%2520Gas%252010_09%2520Handout.pdf+%22pete+stark+2010+shale+gas+ppt%22&hl=en&gl=us&pid=bl&srcid=ADGEEShSbRdYby2vOy1Na8tWuVSGubxQ3BsJrO-j7ZnHet-nMKFWuw-vZ48bRgX-V5X6oKXvq4FM57yzCqy48ACyITxoZKufL2eRrjvMhix2BFtkJPAsT9EKrGJncEwiz8c7vQ88Pt2-&sig=AHIEtbReSD4G5dFubJRZG_GH5YDiZ-ZxTw)

<sup>86</sup> "Fracture Lines: Will Canada's Water Be Protected In the Rush To Develop Shale Gas," commissioned by the Program on Water Issues, University of Toronto's Munk Centre, September 15, , 2010, [http://www.powi.ca/pdfs/groundwater/Fracture%20Lines\\_English\\_Oct14Release.pdf](http://www.powi.ca/pdfs/groundwater/Fracture%20Lines_English_Oct14Release.pdf)

have important implications for the assumptions used to assess direct and indirect carbon intensity associated with the use of shale gas resources. Given this explosive growth, due diligence alone suggests that CARB undertake careful analysis of the specific carbon intensity of this pathway.

According to researchers at Simon Fraser University, shale-derived natural gas at the wellhead can contain two to six times higher CO<sub>2</sub> compared to conventional natural gas sources.<sup>87</sup> These researchers, associated with SFU's Pacific Center for Climate Solutions, report that raw natural gas extracted from shale in the Horn River Basin contains approximately 11-12% CO<sub>2</sub>, considerably higher than the average content of only 2-4.5% for B.C.'s conventional natural gas reservoirs. In British Columbia, the Spectra Energy Fort Nelson natural gas processing plant and the proposed EnCana Cabin plant will be the two largest point-sources of emissions in the province, with processing capacities of 790 and 800 MMcf/day, respectively. Encana's shale gas processing Cabin Gas Plant will emit 2 million metric tons of GHG a year, while Spectra's two shale gas plants will release nearly 3 million tons. Much of this capacity will be available to service demand in California. The SFU report also notes a study by Al Armendariz of SMU, which estimates that shale gas production in the Barnett Shale in north-central Texas can create 33,000 short tons per day of CO<sub>2</sub>e (or the equivalent emissions of two 750 megawatt coal-fired power plants).<sup>88</sup>

It is worthwhile to put the emissions estimates prepared by Armendariz into perspective. In 2009, the Texas Railroad Commission estimated that 1.76 trillion cubic feet of natural gas were produced from the Barnett shale.<sup>89</sup> This represents about 8% of the total natural gas consumed in the U.S. in 2009, and about 25% of the natural gas used for electric power generation in that year.<sup>90</sup> Further, if one divides the 2009 CO<sub>2</sub>e emissions (33,000 tons per day) by the total gas production in 2009, a value of 6.3 gCO<sub>2</sub>e/MJ is obtained.<sup>91</sup> This result is actually lower than that estimated by CARB for production and processing emissions associated with North American natural gas for the LCFS (which assigned 3.5 gCO<sub>2</sub>e/MJ to recovery, 3.7 gCO<sub>2</sub>e/MJ to processing, and 0.97 gCO<sub>2</sub>e/MJ to transport and distribution),<sup>92</sup> and it may reflect an overestimate as drilling and completions emissions should be amortized over the life of the wells.

---

<sup>87</sup> "Shale Gas and Climate Targets: Can They Be Reconciled?", Pacific Institute for Climate Solutions, Mark Jaccard and Brad Griffin, School of Resource and Environmental Management, Simon Fraser University, June 14, 2010, <http://www.pics.ubc.ca/assets/pdf/publications/Shale%20Gas%20and%20Climate%20Targets.pdf>

<sup>88</sup> Al Armendariz, Southern Methodist University's Department of Environmental and Civil Engineering, [http://www.edf.org/documents/9235\\_Barnett\\_Shale\\_Report.pdf](http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf)

<sup>89</sup> See [http://www.rrc.state.tx.us/barnettshale/NewarkEastField\\_1993-2009.pdf](http://www.rrc.state.tx.us/barnettshale/NewarkEastField_1993-2009.pdf)

<sup>90</sup> EIA has estimated total natural gas consumption in the U.S. in 2009 at 22.7 trillion cubic feet of gas and consumption for electricity generation at 6.9 trillion cubic feet. See [http://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcunus\\_a.htm](http://www.eia.gov/dnav/ng/ng_cons_sum_dcunus_a.htm)

<sup>91</sup>  $(33,000 \text{ tpd CO}_2\text{e} * 365 \text{ days/yr} * 2,000 \text{ lb/ton} * 454 \text{ g/lb}) / (1.76 * 10^{12} \text{ scf} * 0.98 \text{ MJ/scf}) = 6.3 \text{ gCO}_2\text{e/MJ}$

<sup>92</sup> See Table A of [http://www.arb.ca.gov/fuels/lcfs/022709lcfs\\_cng.pdf](http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cng.pdf)

As noted above, all shale gas will not necessarily have higher GHG emissions than conventional gas, however. For example, the following selected data on CO<sub>2</sub> content in natural gas has also been reported:<sup>93</sup>

- Barnett Shale (TX) – 4 samples with CO<sub>2</sub> content of 0.3%, 1.4%, 2.3%, and 2.7%
- Marcellus Shale (Northeast) – 4 samples with CO<sub>2</sub> content of 0.1%, 0.1%, 0.3%, and 0.9%
- Fayetteville Shale (AR) – 1 sample with CO<sub>2</sub> content of 1.0%
- New Albany Shale (IL) – 4 samples with CO<sub>2</sub> content of 5.6%, 7.4%, 8.1%, and 10.4%
- Antrim Shale (MI) – 4 samples with CO<sub>2</sub> content of 0.0%, 3.0%, 3.3%, and 9.0%
- Haynesville Shale (LA/TX) – 1 sample with CO<sub>2</sub> content of 4.8%

The proper attribution and allocation of such associated CO<sub>2</sub> emissions is therefore an important part of the WTW carbon intensity calculus of the LCFS. For the two major sources of British Columbia NG cited above (i.e., the Spectra Energy Fort Nelson natural gas processing plant and the proposed EnCana Cabin plant) upstream carbon intensity associated with the CO<sub>2</sub> scrubbing of these facilities would represent 7.2 gCO<sub>2</sub>/MJ,<sup>94</sup> although other estimates place the value at 6.0 gCO<sub>2</sub>/MJ. This compares to a value of approximately 1.1 gCO<sub>2</sub>/MJ currently assumed in CARB's natural gas analysis prepared for the LCFS,<sup>95</sup> which assumes an average CO<sub>2</sub> removal of about 2% from raw natural gas based on an analysis prepared by Argonne.<sup>96</sup>

The Canadian Association of Petroleum Producers have recognized the changing underlying carbon intensity of natural gas resources:

*“While not all shale gas contains significant amounts of CO<sub>2</sub>, the potential growth in carbon emissions from some shale gas is being addressed with proposals for carbon capture and sequestration.”*<sup>97</sup>

The changing underlying characteristics of natural gas resources is important, as over 85% of California natural gas is derived from out-of state regions, including British Columbia. Given the potential for higher carbon intensity associated with shale gas based pathways, CARB should therefore undertake additional analysis of the marginal CO<sub>2</sub> emissions associated with shale natural gas supply pathways, as distinct from conventional natural gas pathways.

<sup>93</sup> “Compositional Variety Complicates Processing Plans for US Shale Gas,” Keith A. Bullin and Peter E. Krouskop, Oil & Gas Journal, March 9, 2009.

<sup>94</sup> See Table 5, attached

<sup>95</sup> See page 27 of [http://www.arb.ca.gov/fuels/lcfs/022709lcfs\\_cng.pdf](http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cng.pdf)

<sup>96</sup> See page 60 of <http://www.transportation.anl.gov/pdfs/TA/155.pdf>

<sup>97</sup> National Energy Board (2009), “Energy briefing note: A Primer for Understanding Canadian shale gas”

**Table 5.** Upstream CO<sub>2</sub> in Raw Shale Gas from the Spectra and Encana Gas Plants Planned in British Columbia (Assumes 10% CO<sub>2</sub> Content in Raw Natural Gas is Removed)

BCF per day natural gas production	1.6
Annual CO <sub>2</sub> , tons	5,000,000
MMBtus per BCF	1,026,000
MJs per MMBtu	1,055
MJs per BCF	1,082,430,000
BCF per year	584
CO <sub>2</sub> tons per BCF	8,562
gCO <sub>2</sub> per MJ	7.2

### 7.3 The margins of electricity generation markets

Aside from natural gas resource depletion itself, there is also the issue of re-allocating natural gas from power markets to transportation markets. Using increasing quantities of natural gas for vehicle propulsion will increase demand and price for natural gas, which in turn could have a significant effect on ancillary markets that currently rely on natural gas (i.e. power markets). The magnitude of this effect will depend on several variables, including but not limited to the size of existing natural gas reserves, the cost and availability of securing new reserves, the size of the NGV fleet over time, and the myriad of market forces that will increase or decrease the potential market-mediated effect of using more natural gas in transportation fuel markets. As is the case elsewhere in this report, there is a paucity of data with regard to the potential market-mediated effect of shifting natural gas markets. However, there are reports suggesting a potentially significant effect.

As discussed, McCarthy et al. utilized a model (denoted as EDGE-CA) to evaluate the current composition and mix of electricity power generation in CA to determine the short- and mid-term impact of advanced engine deployment and its impact on marginal electricity demand. While there have been some questions raised about the characteristics of the model shock, the report nonetheless produces CI numbers much higher than those currently included in the CA LCFS for electricity and hydrogen. This report is relevant to natural gas because re-allocating natural gas from power markets to transportation markets will force power producers to look elsewhere to produce power (i.e. like increased electricity demand, will drive electricity producers to the margin of the sector). As discussed, the magnitude of this response will depend on the magnitude and time period of the change. However, this potential market-mediated response is very similar to ILUC. In essence, biofuels could deprive food and feed

markets of land/grain, driving producers of food and feed to other new resources. The same is potentially true for natural gas and power producers. It is also worth noting that relatively small changes in electricity markets can produce significant market responses. For example, a 2005 study by R. Weiser et al. of Lawrence Berkeley National Laboratory, which averages the results of 13 other studies, found that a one percent reduction in natural gas demand would result in a 0.8-2 percent long-term average reduction of wellhead natural gas prices.<sup>98</sup> This type of price response suggests that even relatively small re-allocations of natural gas from power to transportation markets could have a significant effect on pricing and therefore price-induced response.

#### **7.4 Recommendations**

- **ARB or related entity should initiate a rigorous analysis of the margin of the natural gas sector, with regard to both type and carbon intensity of marginal natural gas fuels.**
- **ARB or related entity should initiate a rigorous analysis of the margin of the electricity sector as a function of increased natural gas use in the transportation sector. This analysis should be co-joined with the marginal electricity analysis conducted pursuant to electricity and hydrogen fuels discussed above.**

---

<sup>98</sup> Wisser, R., M. Bolinger, and M. St. Clair. 2005. Easing the natural gas crisis: Reducing natural gas prices through increased deployment of renewable energy and energy efficiency. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory. January. Online at <http://www.lbl.gov/Science-Articles/Archive/sabl/2005/February/assets/Natural-Gas.pdf>.

## 8.0 Appendices

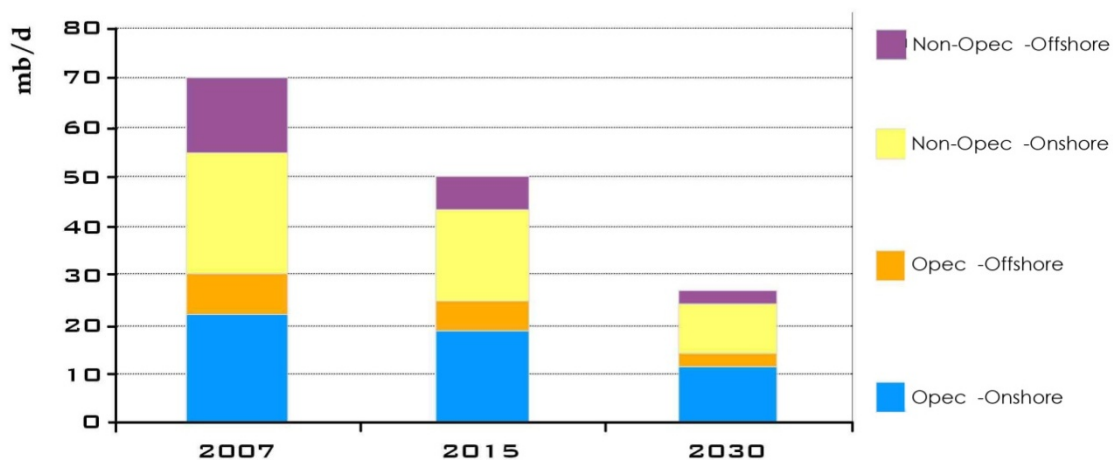
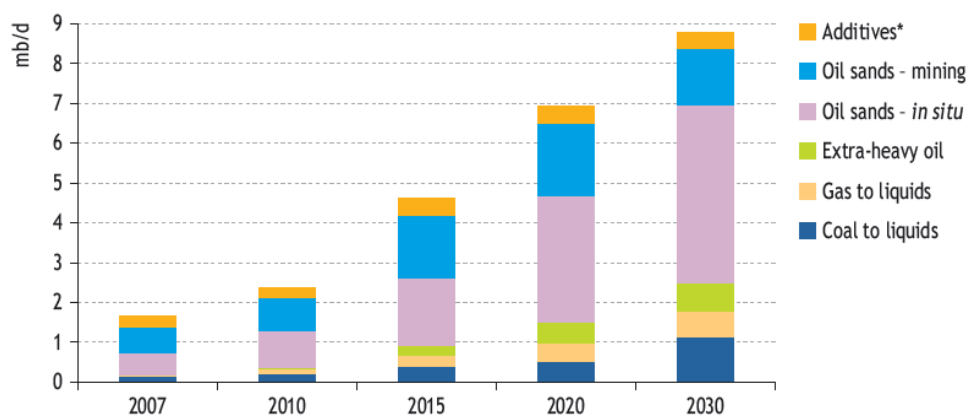


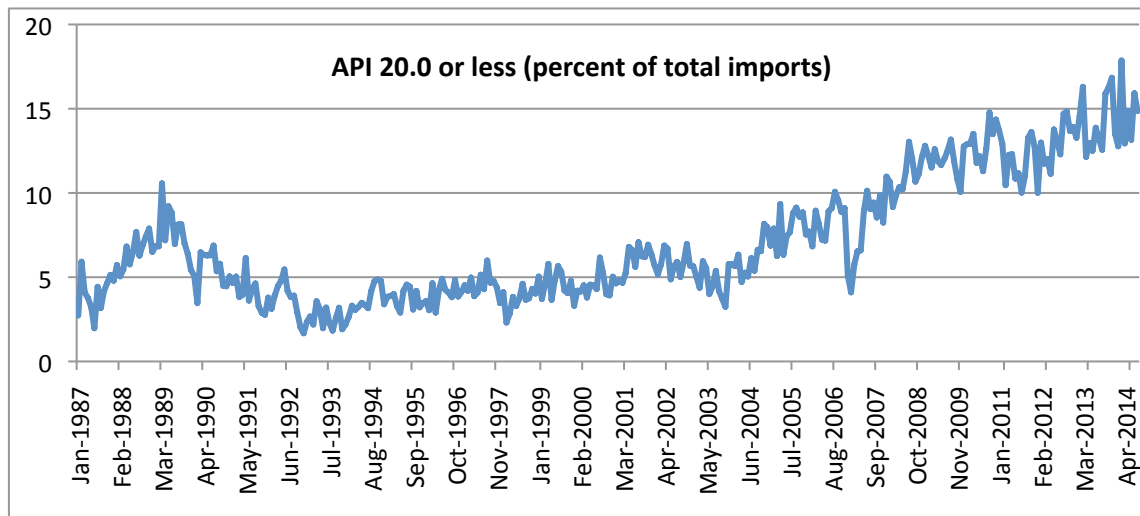
Figure S1: Development of petroleum production in current fields. Source: IEA 2008

**Figure 11.12** • World non-conventional oil production by type in the Reference Scenario



\*Methyl tertiary butyl ether (MTBE) and other chemicals.

Figure S2: World non-conventional oil production by type in the Reference Scenario. Source: IEA 2008.



**Figure S3: US crude oil imports: Development of heavy oil imports. Source EIA 2010.**