THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

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August 30, 2012

Steve Cliff
Chief of the GHG Market Development and Oversight Branch
California Air Resources Board
Sacramento California

Subject: Oil Production Cap and Trade Leakage Evaluation

Dear Mr. Cliff:

Thank you for the opportunity to submit comments on CARB's process for re-assessing industrial leakage potential under the cap and trade program. We recommend that you revise the oil production leakage designation from high to low due to several factors.

First, CARB has noted that oil extraction falls into the category of activities that "have to be located where the reserve is" (CARB Appendix K p26, Leakage Analysis). In addition, oil producers have invested many billions of dollars in fixed well, pump, field treatment, pipeline, and tankage facilities. Thus, oil production is a domestic captive supplier.

Furthermore, CARB greenhouse gas (GHG) allowances are unlikely to have any significant effect on production for two reasons. First, profit margins would not be significantly affected even if GHG allowance prices were to add a dollar or two per barrel to production costs. For instance, Midway-Sunset crude oil prices have tripled over the last decade. Second, production levels have been driven by reservoir depletion rather than margins even at historic high prices.

Thus, we recommend designating oil production as subject to low risk of leakage. Please see our attached detailed June 6, 2011 comments and feel free to contact me at ed@theicct.org or Chris Malins, ICCT fuels program lead, at chris@theicct.org with any questions.

Sincerely,

Ed Pike

Ed Pike, PE
Senior Researcher, International Council on Clean Transportation

Attachment

cc: Mary Jane Coombs, CARB
Mihoyo Fuji, CARB
John Courtis, CARB

THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

June 6, 2011

Richard Corey
Chief, Stationary Source Division
California Air Resources Board
1001 I Street
Sacramento, California 95812

Subject: Proposed Greenhouse Gas Cap and Trade Crude Oil Production Allocations

Dear Mr. Corey:

Thank you for the support you and CARB staff have provided in the development of the two major Economic and Technology Advancement Advisory Committee (ETAAC) reports on advanced technology development in California. AB32 offers major opportunities to transition California to a cleaner and more efficient economy with reductions in both greenhouse gases (GHG) and criteria pollutants as recommended by the ETAAC. The distribution of GHG allowances will play a major role in determining whether cap and trade helps achieve these goals in the transportation sector including fuel producers.

In the case of crude oil producers the ICCT recommends providing any output based free allowances at roughly 5 g CO_2/MJ based on CARB's LCFS documentation of emission levels for producers representing over half the state's production. We do not recommend an automatic GHG allowance bonus for higher carbon intensity steam enhanced production of heavy crude, which results in higher GHG and criteria pollutants both in the oilfield and when refined. Instead we recommend using additional allowances as incentives for producers to move to cleaner and more efficient production methods as well as transitioning our transportation system to cleaner alternatives.

Please see our attached comments for additional information on crude oil production, emissions, and allocation options. If you have questions about our comments, you or your staff should feel free to contact me at ed@theicct.org or (415) 202-5753.

Sincerely,

Ed Pike

Ed Pike
International Council on Clean Transportation

California High Carbon Intensity Crude Production

Purpose

This document describes California high-carbon crudes, reasons for higher emissions, and potential emission reduction options from crude production. This document also shows the insensitivity of production of California high-carbon crudes to leakage under cap and trade currently. In addition, this document recommends setting any output based free GHG allowances to California oil producers at a flat benchmark of approximately 5 g CO2(e)/MJ (20-25 kg/barrel) coupled with incentives for transitioning to cleaner and more efficient production methods.

California high carbon intensity crudes

California has a history of oil production dating to the end of the 19th century.[1] California initially produced mainly light crudes, with heavy crude oil representing 20% of state production in the 1940s. Heavy crude oil production increased in the 1960's with thermal production techniques "despite low heavy oil prices, stringent environmental regulation and long and costly delays"[2] and is now the largest volume crude produced in California.[3]

Heavy crude is often defined as oil with 10 degree to 20 degree API gravity based on density. Heavy crude with high viscosity is challenging to mobilize. Other factors affecting the energy and process used to extract heavy crude oil include the depth and reservoir geology and pressure.

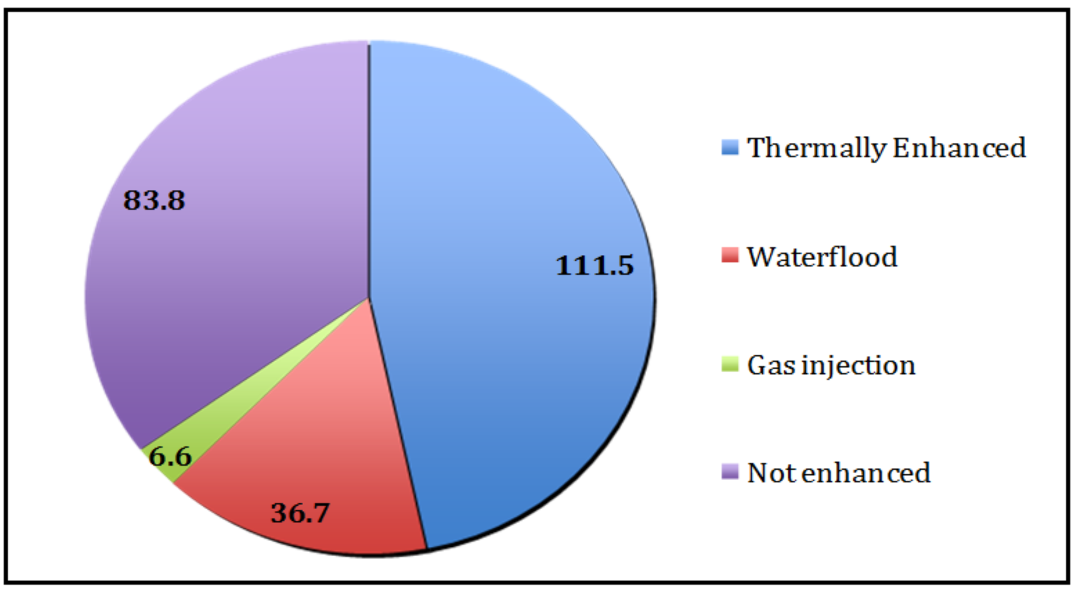

Figure 1: California Crude Oil Production by Methods, million barrels per year (Source: DOGGR)

[1] Advanced Resources International (ARI). 2005. Basin Oriented Strategies for CO2 Enhanced Oil Recovery: California. April. Table 9.

[2] David Olsen and Edwin Ramzel. 1995. State of Heavy Oil Production and Refining in California. National Institute for Petroleum and Energy Research p159.

[3] DOGGR, 2008 Annual Report of the State Oil & Gas Supervisor, p5.

Figure 1 shows volumes of California crude produced using "enhanced" techniques to increase reservoir pressure and/or reduce heavy crude oil viscosity with steam or water injection and less commonly gas injection. Steam injection is the most energy intensive production method. "Steam drive" wells are continuously steamed while oil is recovered from other production wells. The majority of steam in California is injected into "steam drive" wells at levels that vary from oil field to oil field.[4] "Cyclic" wells can be alternatively steamed and produced.

Steam is produced in cogeneration plants or at steam generators configured in banks or individually. At cogeneration plants, hot combustion gases spin a turbine to generate electricity and residual heat is extracted to generate steam. In a cogeneration plant with a heat rate of 11,000 btu per kw-hr of electrical output, 30% of the energy content of natural gas is recovered as electricity and remaining heat from combustion passes through a heat exchanger for steam generation. CARB has estimated in the cap & trade rulemaking documentation that lower efficiency boilers (i.e. steam generators) in the petroleum sector are 80-82% efficient while high efficiency boilers achieve 88%.[5]

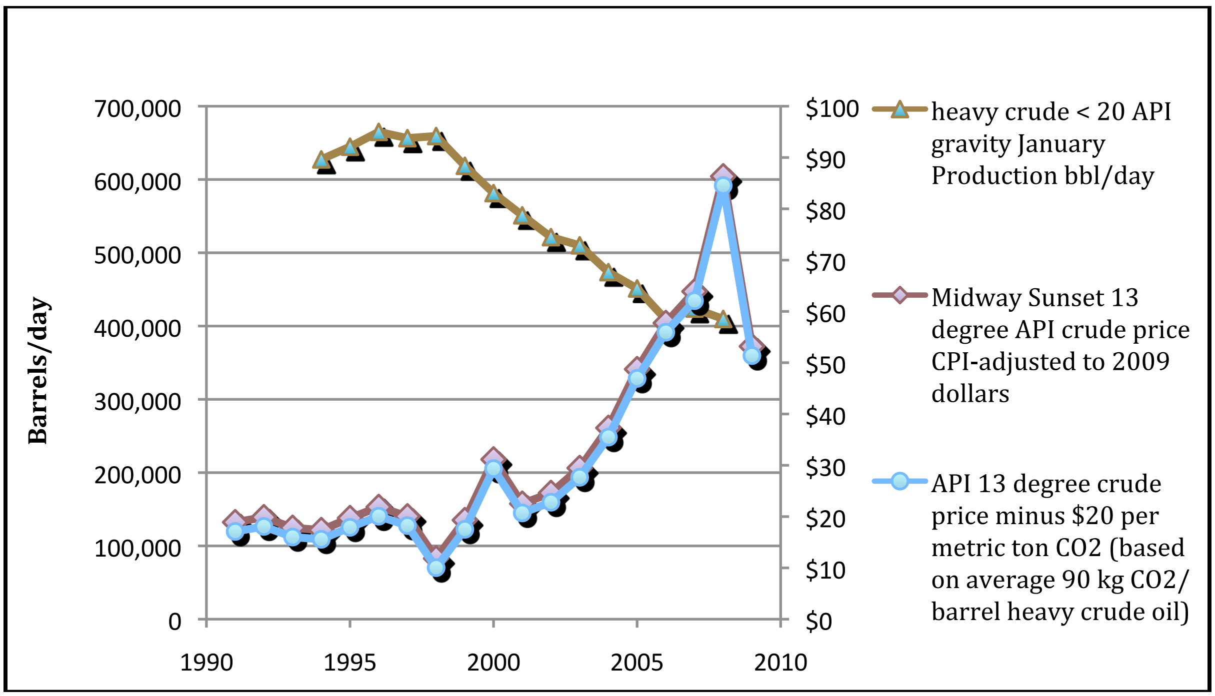

Figure 2: Heavy crude oil prices and production (Sources: Chevron and DOGGR)

As seen in Figure 2, California heavy crude oil production has declined steadily since the late 1990's (this figure also includes information on carbon prices that will be addressed later). A 2005 DOE sponsored report has similarly noted that most oil fields in California

[4] DOGGR, 2008 Annual Report of the State Oil & Gas Supervisor, p9.

[5] CARB's Compliance Pathways analysis is available at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm , last accessed 5-10-2011

were declining in production in the early 2000's.[6] California heavy crude oil production levels dropped by about 35-40% by 2009, despite prices increasing to above $50/barrel.

Emissions

Production and refining of crude oil accounts for the majority industrial sector GHG emissions in California. California high carbon crudes cause local and GHG pollutants in two stages. The first is due to the additional energy needed to recover heavy crudes from underground reservoirs. The second is the additional processing and energy usage during the refining process as explained below.

The most energy intensive method of heavy crude oil production in California is steam injection. Natural gas combusted for steam production creates nitrogen oxides (NOx), a precursor to ground level ozone and fine particulates. NOx has been reduced, though not eliminated, due to rules such as the San Joaquin Valley Unified Air Pollution District Rule 4306 as part of air quality plans to remedy persistent unhealthy air quality. Internal combustion engines for oil & natural gas production are also a significant source of NOx. Total statewide emissions of NOx from oil and gas production is predicted to remain slightly above 20 tons per day from 2010-2015 according to the California Emissions Forecasting System.[7]

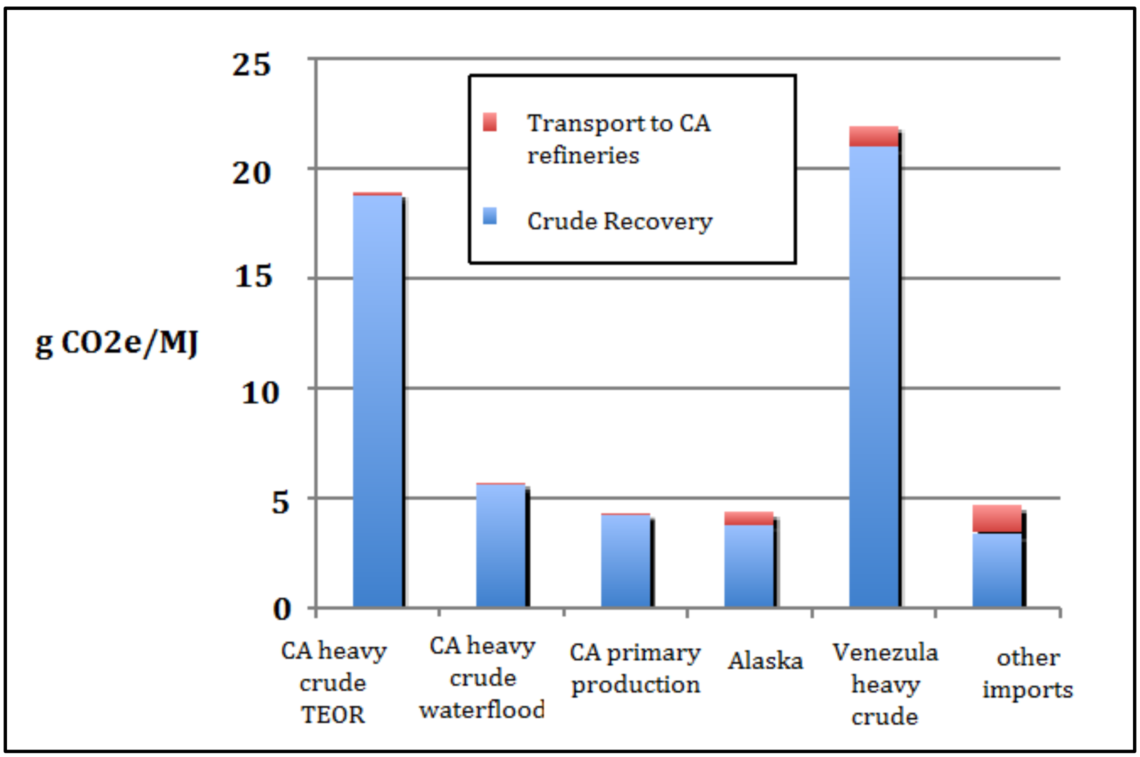

Figure 3: Crude Oil Production values in g CO2/MJ
(Source: CARB)

[6] ARI 2005. page 3-3.

[7] http://www.arb.ca.gov/app/emsinv/fcemssumcat2006.php

As seen in Figure 3, CARB's Low Carbon Fuel Standard report shows that California heavy crude oil production is several times more carbon intensive at the production stage compared to light crudes. This is largely due to combustion emissions from steam generation as show below in Figure 4. Demand for steam and secondarily the efficiency of process equipment are the primary factors determining CO2 from steam generation. CARB's LCFS analysis assumes that the Kern River case represents 40% of total production with a steam-oil ratio of about just over 3:1 while the Midway-Sunset /South Belridge case represents the other 60% of California TEOR production with a steam-oil ratio of just over 5:1. Thus the amount of energy and emissions from steaming wells will vary significantly.[8]

Electricity uses, such as lifting crude from underground, also result in criteria pollutants and carbon dioxide for either on-site or imported electricity if it is generated from fossil fuels. (Transport of crude oil is a relatively minor source of GHG intensity for both domestic and imported crudes according to LCFS data.)

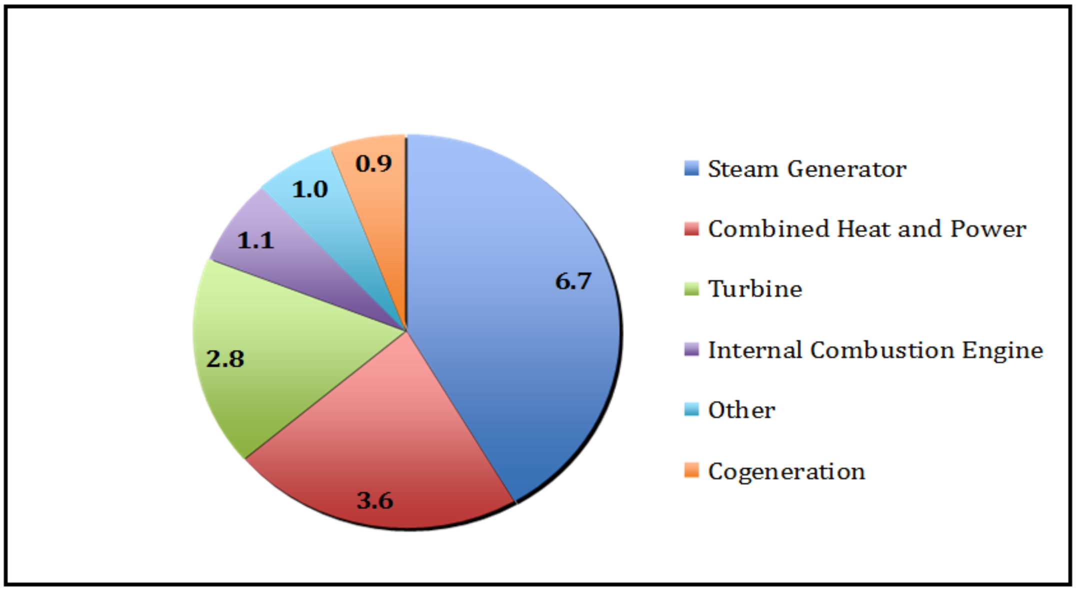

Figure 4: Combustion Emissions by Type, 2007 CARB Survey in Million Metric Tons CO2(e) (Source: CARB)

California heavy crude oil also results in additional California refinery emissions. "In general, a refinery's emissions depend on the crude oil's weight (API) and the degree of cracking, determined by the product yield."[9] California heavy crude is a major feedstock to California refineries along with other types of feedstocks. Figure 5 shows the relative carbon intensity of different process units per ton of process throughput. The carbon intensities are shown relative to distillation; in theory an ideal light crude would yield the desired mix of end products after distillation. The carbon intensities for the different additional processes needed to refine heavy crude are not necessarily additive, i.e. a feed of

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[8] California Air Resources Board. 2009. Proposed Regulation to Implement the Low Carbon Fuel Standard, Vol II Appendices. March 5. pC-58.

[9] Ecofys. 2009. Methodology for the free allocation of emission allowances in the EU ETS post 2012 Sector report for the refinery industry. November. page 5

one barrel of heavy crude would not result in one additional barrel of cracking and coking as some products would likely be separated out at the distillation column (or parts of some product steams may be processed more than once in a given unit). Production of hydrogen via steam methane reforming, a carbon intensive process used at refineries to treat high sulfur crudes, is reported using a different metric than the values shown in Figure 5.

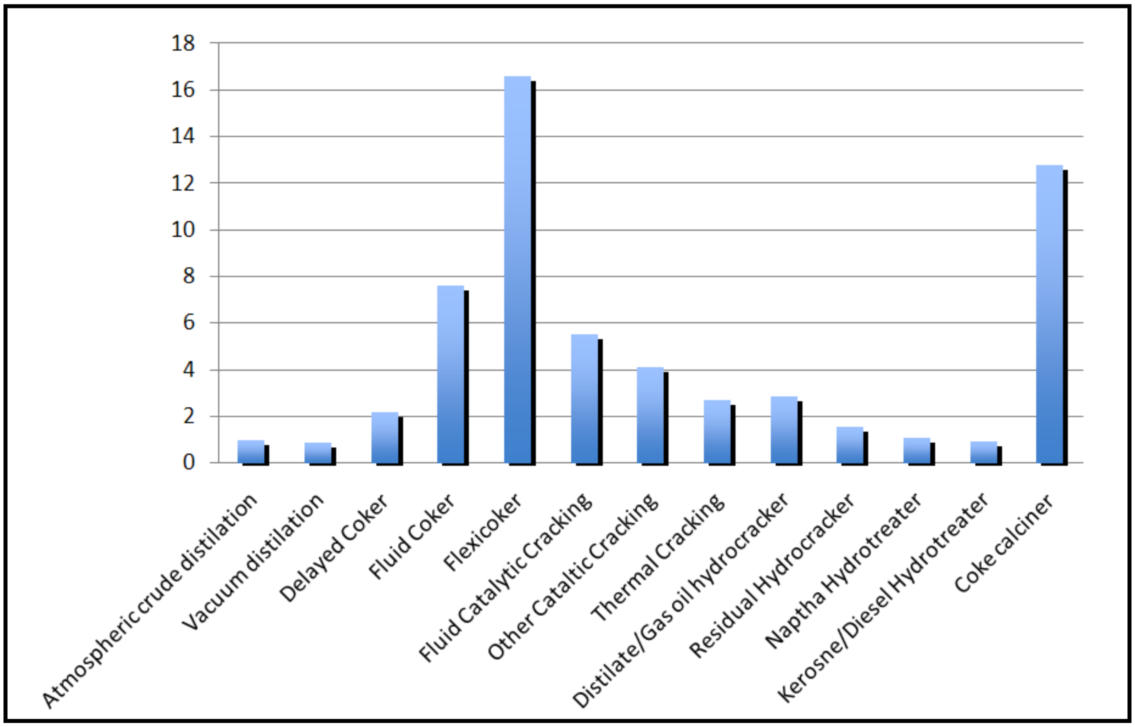

Figure 5: Carbon intensity of refinery operations relative to atmospheric crude distillation (Source: Ecofys)

<u>Emission control strategies</u>

There are a number of options for reducing emissions from California high carbon crudes. End use efficiency through improved technology and improved operation for conventional vehicles, advanced technology vehicles[10], and lower passenger vehicle miles will reduce petroleum dependence and associated GHG and criteria pollutant emissions. Lower carbon liquid fuels may be another option to reduce consumption of high carbon crudes.

Efficient production methods can reduce the production emissions from high carbon heavy crude, though without addressing downstream refinery emissions and total petroleum demand. Water injection is a lower carbon strategy than steam injection, though it may not be viable for all wells. Replacing aging cogeneration plants producing steam and power with high efficiency plants would improve the efficiency of fossil steam and electricity generation. In addition, CARB's "Compliance Pathways" analysis has identified the potential for saving over one million metric tons per year GHG emissions from replacing less efficient

[10] For evaluation of fuel cell and battery electric emissions see Chuck Shulock, Ed Pike, Alan Lloyd, Robert Rose. Passenger Vehicle Electrification Policy report Task #1: Technology Status. pages 40-43.

steam boilers and improving steam efficiency.[11] This would also reduce associated fossil combustion emissions such as NOx. Based on the data presented in the CARB cap & trade compliance pathways analysis, the simple payback period for boiler replacement and steam efficiency measures would range from 1.5 to 6 years, excluding environmental benefits and reduced GHG allowance requirements.

Solar thermal technology can displace fossil fuels used to generate both steam and electricity in oil fields. This technology is being demonstrated in California for steam-based electricity generation and has potential application to oilfield steam and electricity generation. One solar thermal technology uses parabolic mirrors to heat a working fluid that passes through a heat exchanger to generate steam (development of steaming cycles to match solar availability, if feasible, would avoid the need for natural gas back-up). Another technology focuses arrays of mirrors on a "power tower" to store heat in a high-temperature medium with the potential for steam and power generation along with energy storage. These new technologies may encounter the "Valley of Death" between demonstration and commercialization, as noted by the Economic and Technology Advancement Advisory Committee. Examples of barriers include higher upfront capital costs, even for technologies with lower lifetime costs, demonstration risks, and external benefits.[12]

Carbon dioxide injection is another potential emission control strategy. A report sponsored by the Department of Energy's Office of Fossil Energy estimates that 1.8 billion barrels of California light and heavy crude oil would become economically recoverable with state of the art CO2 injection and a $25/barrel oil price.[13] Carbon dioxide injection to improve the mobility of heavy crude oil would have different potential effects on net carbon dioxide emission. On one hand CO2 usage could displace existing steam generation for heavy crude production, and some of the CO2 typically remains underground (the remainder is typically recovered for reuse). On the other hand, CO2 could be used to produce heavy crude oil deposits that could not otherwise be recovered according to the US DOE sponsored report and thus increase the CO2-intensity of California refineries.[14]

<u>Low sensitivity to carbon prices</u>

"Leakage" has been noted by the California Air Resources Board as a concern in cases where a cap & trade system could create an incentive to move production activities out of state. This does not appear to be a significant issue for domestic captive producers such as oil producers. Oil producers cannot relocate California's oil resources to a different state to avoid California regulation of in-state oil production, and also cannot curtail production without also cutting revenue. As prices have increased, heavy crude oil production has steadily decreased as shown in Figure 2. In the mid-1990's, with prices about $10-$12 per

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[11] CARB's Compliance Pathways analysis is available at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm , last accessed 5-10-2011

[12] Economic and Technology Advancement Advisory Committee. Advanced Technology to Meet California's Climate Goals: Opportunities, Barriers & Policy Solutions pages 1-9 through 1-11.

[13]ARI 2005. Table 2.

[14] CO2 injection faces a number of technical and geological uncertainties, environmental issues such as water quality effects, economic barriers and liability issues.

barrel or around $18-$20 in 2009 dollars, and environmental costs of 20% (such as NOx emission controls) production was over 600,000 barrels/day as shown in figure 2.[15] [16] By contrast, prices are much higher now, environmental costs are a much lower percent of revenues even with the purchase of GHG allowance, and available reserves are the primary limiting factor for production levels closer to 400,000 barrels/day.

Region	Regulator Compliance ($/bbl)	Production 1,000 bbl/d	Regulatory compliance as percentage of lifting cost	Average lifting cost ($/bbl)	Wellhead price ($/bbl)
Santa Maria (Coastal)	$2.05	34	18%	$11.22	$10.75
Long Beach and Tidelands (Los Angeles)	$2.39	136	27%	$8.99	$12.00
Ventura and Tidelands (Los Angeles)	$1.73	52	15%	$11.87	$12.80
San Joaquin	$0.55	746	9%	$5.94	$11.75

Figure 6: Historical 1990's Environmental Compliance and Lifting Costs (Source: National Institute for Petroleum and Energy Research)

In addition, producers have large stocks of existing capital equipment in wells, pumps, pipelines, tankage and other equipment. These factors weigh against the possibility that California oil production would decline and be replaced by out-of-state sources (i.e. leakage) due to the cost of purchasing GHG allowances.

California cap & trade allowance allocations recommendations

The California Air Resources Board has adopted a cap and trade system that includes oil producers beginning with Phase I from 2012-2014. The ICCT recommends that California use the value of cap & trade transportation sector allowances, including petroleum fuels production and refining, to support strategies that transition California's transportation sector to a cleaner and more efficient economy and incentives for more efficient production of California crude oil.

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[15] San Joaquin lagged at that time as noted in Figure X, but has subsequently adopted additional control rules such as NOx Rule 4306 noted above

[16] Olsen and Ramzel 1995, p159

Allocations to oil producers should focus on adoption of renewable energy technologies to generate steam and electricity to overcome advanced technology development barriers and also encourage associated criteria pollutant co-benefits. Bonus allowances could be reserved based on renewable energy installed capacity and then distributed based on annual renewable production levels. [17] One factor to consider in establishing the level of bonus payments is the average level of criteria pollutants avoided compared to the amount that California pays to reduce such emissions under incentive programs such as Carl Moyer. Another is technology development benefits.

Output-based GHG allowance allocations are another option that could be coupled with incentives for transition during phase I. CARB has proposed the output-based approach for the industrial sector in many cases based on the expectation that cost savings could reduce costs to producers as a hedge against possible leakage and/or could be passed on to consumers to moderate potential price impacts. Given that oil prices are set on a global market, and that leakage is not a significant risk, these factors need not play a significant role in any free allocations that CARB chooses to provide to industry in phase I of the California GHG Cap & Trade system.

We recommend a benchmark of approximately 5 g CO_2/MJ (20-25 kg/barrel) for any output based allowances. This value is based on light crude oil and non-thermally enhanced heavy crude, which are both close to 5 g CO_2/MJ using data from CARB's LCFS studies (see figure 3), and represents over half of in-state production (see figure 1). Benchmarks granting a higher level of subsidy for more carbon intensive processes, such as thermally enhanced oil recovery (TEOR) at 18 g CO_2/MJ (90 kg/barrel), just because they are higher emitting are not recommended. The higher level would reward a production process with higher GHG emissions and criteria pollutants both on-site and downstream during the refining process. In addition, granting extra allowances would create windfall profits for the production of TEOR crudes with emissions above 5 g CO_2/MJ and below 18 g CO_2/MJ. TEOR producers would instead have the opportunity to qualify for greater free allocations by investing in emissions reductions described earlier. Any benchmarks for output based free allocations should be set at approximately 5 g CO_2/MJ, with remaining free allowances allocated for transitioning to more efficient and less polluting transportation systems and crude oil production processes.

[17] A kw-hr of electricity can be directly converted to BTU and vice versa; however given the higher energy content typically required to produce a kw-hr of electricity vs a BTU of steam a multiplier for electricity would be appropriate. For instance, electricity could receive a 1.5x multiplier compared to steam.