Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions

Stakeholder Input

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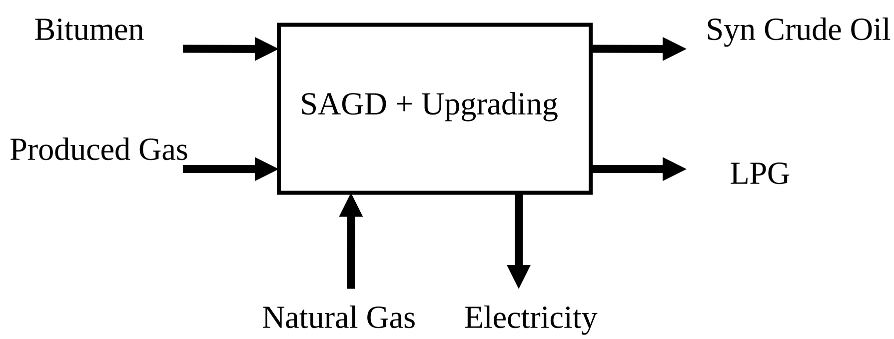
Stakeholder Input I. Stakeholder Workshop

A Workshop was held on January 16, 2009 to provide an opportunity for stakeholders to review our interim progress. The Workshop Attendees asked many good questions and provided instructive comments. The following is a summary of the questions/comments received and TIAX responses. The comments have been divided into the following categories: GREET Efficiency, Treatment of Coke, Conventional Crude Data, Oil Sands Data, Venting and Flaring Data, General Comments. We appreciate the time/effort to review the interim data, attend the workshop, and provide comments.

GREET Efficiency Explanation

At the workshop there was general confusion about the term efficiency as used in the GREET model. We use the following energy flows as an example:



Anand Gohil of Nexen has clarified that the petroleum industry definition of plant efficiency is how much additional energy is required to make petroleum products. Therefore, the industry defines efficiency as:

$$Efficiency = 1 - \frac{Net\_Inputs}{Petroleum\_Outputs}$$

$$Efficiency = 1 - \frac{516 - 70.2}{6170 + 65.4} = 93\%$$

In the GREET model, the efficiency is defined as the total amount of energy consumed in making all energy outputs. Therefore, the energy in the bitumen that is used as process fuel is also considered. The process efficiency is defined in GREET as:

$$GREET\_Efficiency \equiv \frac{Total\_Outputs}{Total\_Inputs}$$

For our example, the GREET efficiency would therefore be:

$$GREET\_\eta = \frac{SCO + LPG + Electricity}{Bitumen + ProducedGas + NaturalGas} = \frac{6170 + 65.4 + 70.2}{8570 + 44.8 + 516} = 69\%$$

This definition of efficiency includes the energy in the bitumen and produced gas that are utilized to make SCO. In the GREET model, this value for efficiency is utilized to determine the amount of process fuels consumed to produce SCO, LPG and electricity:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.69} - 1 = 0.448$$

Check:

$$Process\_Fuels = Prod\_Gas + NG + (Bitumen - SCO - LPG - Elec) = 2825 MJ$$

$$Energy\_Output = SCO + LPG + Electricity = 6305.6 MJ$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{2825 MJ}{6305.6 MJ} = 0.448$$

The next step is to split this energy consumption (448,000 Btu/mmBtu SCO) among process fuel types. In this case, the process fuels are produced gas (44.8 MJ), natural gas (516 MJ) and the balance is syngas produced from gasification of coke. Note that care needs to be taken here with the syngas composition since a portion of the syngas hydrogen is utilized in upgrading. Once the share of each fuel type is estimated the appropriate GHG emission factors are applied (depends on assumed combustion equipment split for each fuel type) to arrive at total GHG emissions per mmBtu SCO.

In this example, the exported electricity is produced by burning a mixture of natural gas, produced gas and syngas. This electricity has a lower GHG footprint than the average grid mix (which includes a significant portion of coal). It could be argued therefore that the process should get a credit equivalent to the difference between the CO2e/MWh generated onsite and CO2e/MWh that it displaces. A variety of things could be selected as the electricity displaced: provincial mix, NG combined cycle turbines, etc. The mix selected will be clearly noted along with the results. If time and budget are available, TIAX will vary this and show the impact on CO2 emissions.

To capture the credit, we need to take the electricity export out of the efficiency calculation (increase natural gas fuel consumption) and then subtract out the electricity energy as a line item. The model will automatically subtract out the GHG emissions associated with the specified grid mix electricity.

With the electricity credit method, the GREET efficiency is:

$$GREET\_\eta'' = \frac{SCO + LPG}{Bitumen + ProducedGas + NaturalGas} = \frac{6170 + 65.4}{8570 + 44.8 + 516} = 68.3\%$$

The process fuel consumption is higher, but there is an electricity credit (70.2 MJ) that will more than offset the increased NG combustion emissions.

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.683} - 1 = 0.464$$

Comments on Treatment of Coke

There were many comments regarding the accounting of coke. We present a list of comments followed by a detailed explanation of how we anticipate treating coke production.

Ivanhoe Energy:

TIAX needs to make sure it handles coke consistently for oil sands operations with and without integrated upgraders. For the oil sands without upgraders, the coke is produced in the refineries and sold, not stockpiled. If this coke use is not accounted for, it will unfairly bias the results towards U.S. refining.

LENEF Consulting:

Oil sands mining/integrated coker upgraders in the Fort McMurray area could (and do) deliberately "sequester" their coke in the mines, and can in the long term include this in their land remediation. Should such operators be able to claim "Credit" for this deliberate act? If the coke is assumed to be burned in a powerplant, then is a credit granted for the mining, transport, and burning of coal?

Suncor:

Different oil sands companies manage coke differently. At Suncor, 34% of the coke is consumed in the production of SCO with the balance stockpiled or sold. Each company has a different approach to coke and the CO2 profiles will be different.

TIAX Methodology for Handling Coke

For each of the oil sands pathways, coke will be produced. For the two onsite upgrading pathways, the coke is produced onsite. For the other two pathways, the coke is produced at the refinery. Regardless of where the coke is produced, it will be treated consistently. The key issue is whether to assign a portion of the recovery and upgrading energy (and therefore emissions) to the coke or to assign all of the energy (and emissions) to the SCO. Further, if some energy is allocated to the coke, what allocation methodology would be employed. In this study we are analyzing two pathways with onsite upgrading:

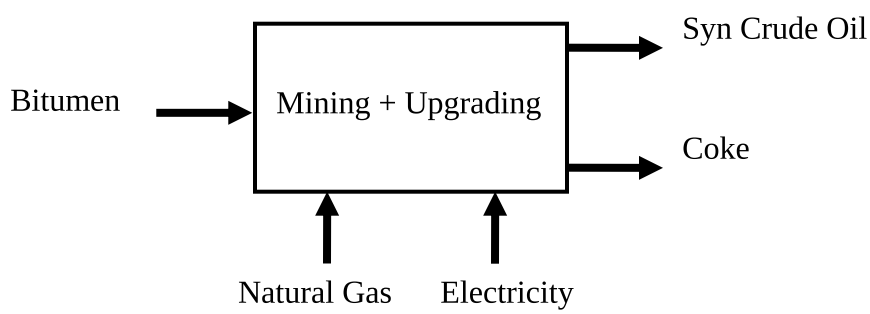
Pathway 1: SAGD+Upgrading: All of the coke is utilized onsite, reducing the quantity of imported NG for steam production

Pathway 2: Mining+Upgrading: The product coke is not consumed onsite

The first pathway is based on the Nexen process. Coke does not exit the control volume, so we do not need to worry about allocating recovery/upgrading energy and emissions to it. Because this pathway utilizes coke to generate steam rather than natural gas, the CO2 emissions will be slightly higher since coke has a higher carbon content per unit energy than natural gas.

The second pathway, mining+upgrading, does not consume any of the coke onsite, so we need to decide whether a portion of the recovery/upgrading energy and emissions should be allocated to it and if so, by what method. We recognize that other pathways are possible (e.g. Suncor utilizes a portion of their coke onsite and stockpiles the balance), however the pathway we are analyzing here does not use the coke onsite.

The Mining+Upgrading pathway is depicted below:



To determine how to split or allocate the recovery energy/emissions between the SCO and the coke, we need to consider the fate of the coke. There are two possible fates:

1. The coke is sold for use as a fuel (or stockpiled for future use as a fuel)
2. The coke is buried and considered sequestered

The manner in which these scenarios will be modeled in this project is described below.

Scenario 1: Coke is Sold for Use as a Fuel (or stockpiled for use at a later time)

If the coke is sold (or will be sold in the future), then it is a useful product and it is appropriate to assign some of the recovery/upgrading energy to it. There are many ways to allocate energy among co-products. One way would be proportionally by energy flows, mass, or economic value. The following shows allocation by energy flows. With this approach, we would first we calculate GREET Efficiency with coke in the numerator since it is a useful output:

$$GREET\_\eta \equiv \frac{Total\_Outputs}{Total\_Inputs} = \frac{SCO + Coke}{Bitumen + NG + Electricity} = \frac{5780 + 1330}{8430 + 384 + 20.9} = 80.48\%$$

This efficiency is utilized in the model to calculate total energy consumption as follows:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.8048} - 1 = 0.243$$

Let's check this value:

$$Process\_Fuels = NG + Electricity + (Bitumen - SCO - Coke) = 1725MJ$$

$$Energy\_Output = SCO + Coke = 7110MJ$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1725MJ}{7110MJ} = 0.243 \quad \text{OK}$$

If we assume that the recovery energy is allocated by energy content to the SCO and Coke, then the SCO recovery efficiency is also 80.48%. When this efficiency is utilized in GREET, the total process energy calculated will be 0.243 Btu/MMBtu SCO produced.

An alternative allocation methodology is the substitution/displacement method. The substitution/displacement method is essentially giving a credit for an avoided emission associated with the product that the co-product is displacing. In this method, all of the energy/emissions are assigned to the main product (SCO), but a credit is applied that is equivalent to the avoided energy/emissions to produce the product that is being displaced. For example, pet coke can be utilized in place of coal in utility boilers. Use of pet coke in the boiler instead of coke would reduce the amount of coal being mined. The substitution method would then credit the SCO energy/emissions with the energy and emissions associated with coal mining. Note that coal mining energy and emissions are not being used as a surrogate for coke production – the coal mining energy/emissions are avoided if the coke is sold for use in place of coal.

The substitution/displacement allocation method is generally preferred to other allocation methodologies as allocating by energy content, mass or economic value can be rather arbitrary. TIAX will clearly document the allocation methodology employed in the analysis. If budget and time allow, we will likely look at both an energy and displacement methodology.

Scenario 2: Coke is Considered Sequestered

In this scenario, the total process fuel consumption is the same as in Scenario 1.

$$Process\_Fuels = NG + Electricity + (Bitumen - SCO - Coke) = 1725MJ$$

However, since the coke is not a useful product, all of this process fuel must be allocated to the SCO. Therefore we can back-calculate the GREET process efficiency from the process fuel and SCO:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1$$

$$\frac{1}{\eta} = \frac{Process\_Fuels}{Energy\_Output} + 1 = \frac{Bitument - SCO - Coke + NG + Electricity}{SCO} + 1 = \frac{1725}{5780} + 1 = 1.2984$$

$$GREET\_\eta = \frac{1}{1.2984} = 77\%$$

When this process efficiency is utilized in GREET, the calculated process fuel consumption will be 0.298 Btu/Btu SCO produced. This is higher than Scenario 1 because we are allocating all of the process energy to the SCO rather than to the SCO+Coke.

Carbon Content of the Coke

At the workshop one topic discussed was whether emissions associated with burning the produced coke downstream are considered. If these emissions are included, then a credit would have to be applied equivalent to the combustion that is being displaced. If the coke is utilized in a coal fired boiler to generate electricity, then the credit would be the lifecycle emissions associated with electricity produced from a coal fired boiler or perhaps the average grid mix. TIAX will not consider the emissions from combustion of the product coke. Once we have allocated energy between the SCO and the coke, we have finished considering coke.

Comments on Conventional Crude Recovery Data

EnCana:

The Alaska North Slope diagram indicates pipeline NG and associated gas used to generate electricity. No pipeline natural gas is used in Alaska – only associated gas.

TIAX calculated the amount of fuel needed to generate the estimated amount of electricity to recover ANS crude. Based on our GOR, supplemental fuel was needed. It is true, however, that almost 85% of the produced gas is re-injected, confirming that no pipeline gas is needed. Our preliminary GOR estimate may be low – we will look into this further. We will use data from the State of Alaska Gas Disposition for 2004 which details associated gas produced and the quantity reinjected.

Shell:

For Saudi Arabian Crude, TIAX is not showing any energy use for desalination

TIAX is aware that some of the recovered water is desalinated and used elsewhere. However, a contact at Saudi Aramco has informed us that the water used for recovery is not desalinated prior to injection. Therefore, the desalination process is outside of our control volume and the associated energy use is not considered.

Unknown:

In Saudi Arabia, excess associated gas is used for space heating – is this accounted for?

Any associated gas that is not used for crude recovery exits the recovery control volume and is included in the numerator of the GREET Efficiency calculation.

Ivanhoe Energy:

Mexico Maya utilizes N2 flood – is TIAX accounting for this?

This will be added to the Mexican crude energy balance. Thank you for providing the DOE EIA nitrogen consumption information as well as the Praxair data on nitrogen production energy use.

Pembina:

Is the energy use associated with cleanup of sour associated gas prior to utilization in CTs taken into account?

TIAX contacted Sulfatreat, a company selling skid mounted H2S removal equipment. Their process is used around the world. Their sales rep for Bakersfield California says that no heating or electricity is required. Typically the pressure of the associated gas is sufficient for flow through the reactor. The gas flows from the reactor directly to steam and electricity generators. We are therefore assuming no additional energy needs to clean the associated gas.

Laricina Energy:

The Alaska water oil ratio seems too high – I would verify through other sources.

TIAX has since found detailed information from the State of Alaska on water production.

Laricina Energy:

Canadian heavy oil electricity supply: power is supplied by the Alberta grid rather than directly by natural gas fired generation.

Thank you – we had not found any specific data on the source of conventional oil recovery electricity and had assumed electricity was self-generated. Joule Bergerson has provided sources indicating that most oil sands/upgrading operators are net electricity exporters to the grid. However, this is not necessarily true for conventional heavy oil recovery.

Unknown:

The GOR for Mexico Maya seems high – could this be gas cap production?

Cantarell Oil Field data for 1996 indicates the produced oil ratio is 372 scf/bbl.

Comments on the Oil Sands Pathways

Unknown:

TIAX is analyzing SAGD+upgrading and SAGD recovery with transport as a synbit. SAGD recovery and transport as Dilbit is also a significant pathway. Why was the SAGD+Dilbit pathway not considered here?

There are many different projects and variations for oil sands operations. The scope of this project originally included analysis of only two oil sands pathways. We have increased this to four in consultation with the Steering Committee. Given this constraint, we do consider SAGD recovery and Dilbit refining, so it may be possible to piece these together to create a SAGD+Dilbit pathway in GREET. We will add this as a GREET pathway if we have resources remaining at the end of the project.

Unknown:

Why did TIAX choose the projects it did for the study? CNRL Horizon's last EIA update was in 2003. Long Lake is the only integrated in-situ/gasifier/cogen/upgrader plant in operation. MacKay River and Christina Lake are the two best SAGD projects currently in operation.

One of the overarching requirements for this analysis is that all of the data utilized be publicly available or releasable so that a high level of transparency is achieved. At the start of the project, TIAX and the Steering Committee decided to evaluate the four oil sands pathway indicated in the Table below based on current and future importance. For these pathways, all of the projects with publicly releasable data were considered. Contact was made with other operators, but no public data was made available

Oil Sands Pathways Considered and Corresponding Projects with Public Data

Pathway	Projects Utilized
Mining to SCO	CNRL Horizon
SAGD to SCO	Nexen/OPTI Long Lake
SAGD to Synbit	MacKay River, Christina Lake
CCS to Dilbit	Cold Lake, Primrose

Unknown:

For the CNRL Horizon project, the value reported for coke stockpiled (4,540 kg/bbl) appears to be much higher than Syncrude and Suncor.

Because the Syncrude and Suncor data are not public, we do not have access to it, nor could we consider it. The value utilized is from the EUB/AENV Supplemental Info, 2003. If this number is inaccurate, it may be in the interest of other operators to provide publishable data supporting a more accurate number.

Unknown:

For the Christina Lake project, the natural gas input seems low (TIAX assumes electricity import = 0 and EnCana runs a cogen plant at Christina Lake).

TIAX went back to our data source (EUB/AENV Application, EIA Supplemental Info, 1998) and found that Christina Lake does import a small amount of electricity. The comparison project, MacKay River, consumes ~29 cubic meters (1100 MJ) more of natural gas than the Christina Lake project and exports 330 MJ of electricity. This corresponds to a turbine efficiency at MacKay River of 30%. Since the CSOR values are equivalent for the two projects, TIAX believes that the natural gas consumption and electricity export values of the two projects are consistent.

Unknown:

For the Imperial Oil Cold Lake project, the natural gas input seems low considering the cumulative SOR is 3.35. In addition, Imperial Oil was the first in situ producer to add cogen (170 MW). It seems unlikely that they are importing electricity from the grid.

Our process data is from the EUB/AENV Application in 2002 and supplemental information in 2003. The CSOR is from a progress report to ERCB in 2008. It is possible that the reported 2008 CSOR is not consistent with the natural gas consumption data in the application. The CSOR is not utilized in the calculations. The Cold Lake application data does not include a cogen unit – is it possible that this was added after 2003?

Laricina Energy:

I believe that a fifth oil sands pathway (dil-bit from SAGD production) should be included as it represents the most promising pathway for reducing the GHG footprint of oil sands production through the use of solvent aided processes, which reduce steam injection requirements. Modeling this pathway should lay the foundation for future evaluations.

Please see response to the first comment in the Oil Sands section.

Laricina Energy:

During the seminar, the issue of bias and data acquisition was raised. To appear unbiased, the project was to source only public data. In the case of oil sands mining, this has lead to the utilization of hypothetical information from projects that are not yet currently operating. The omission of Syncrude and Suncor in the data set, because … the data are not publicly available will result in an inaccurate view of oil sands mining operations. I would recommend obtaining private data from these companies to provide a complete and credible data set for oil sands mining.

TIAX understands this frustration, but the overarching requirement for this project is transparency, so the underlying data must not be secret.

Laricina Energy:

Much of the product shipped to the USA from Canada is blended with other conventional crudes to create a more marketable product that is known as Western Canada Select (WCS) rather than shipped as separately as dilbit, synbit, or SCO. This blending will serve to reduce the emissions footprint on a barrel shipped to the USA. Please ensure that the shipped oil volumes are characterized by the correct oil assay.

The intent of the project is to accurately characterize each oil sands pathway deliverable, not a single composite WCS. We are utilizing representative assays for each (SCO, dil-bit and synbit) crude delivered to the refinery.

Ivanhoe Energy:

On Slide 51, the 2500 mile transport distance from Edmonton to PADD 3 ends in west Texas. Shouldn't this be extended to the Gulf Coast?

TIAX agrees and we will adjust this distance to reflect the increased pipeline distance to the Gulf Coast.

Comments on Venting and Flaring Data

API:

Consult December 2008 World Bank report on venting and flaring emissions.

TIAX was unable to find this report on the World Bank website, but we are utilizing 2007 satellite data to complement the EIA/IEA data.

NRCan:

Use World Bank venting and flaring data with caution

TIAX will utilize World Bank data with caution.

Unknown:

Determine how NETL venting and flaring data (EIA/IEA data) were obtained to better understand the data validity.

TIAX is currently going through the source data utilized in the NETL report and will provide the origin of the venting/flaring in the final report. TIAX has contacted EIA for the specific references for international venting and flaring.

API:

It is not accurate to use U.S. average venting/flaring values for Alaska, CA and Gulf Coast.

TIAX agrees and will try to provide more granularity. So far we have:

- *For California, we obtained California District 4 (Kern County) flare volumes from the California Department of Conservation. Venting is prohibited in San Joaquin Valley by the local air district, however it is not zero. Venting emissions will be taken from the California GHG inventory.*
- *For Alaska, venting and flaring data were obtained from the Alaska OGCC Gas disposition reports for 2004.*
- *For Texas, the Texas Railroad Commission has been contacted for gas disposition data. If this cannot be obtained TIAX will use USEPA estimates for federal offshore Gulf of Mexico venting and flaring.*

API:

What is the source of flare emission factors in GREET? The flare emission factors in the API compendium are more accurate.

The GREET documentation does not source the emission factors other than that they are natural gas combustion factors. Unless the flare gas composition is known, the API flare emission estimation methodology is: assume flare gas composition (80% methane, 15% ethane, 5% propane), 98% combustion efficiency (2% of methane is emitted as methane). Using this methodology, the GREET and API CO2 factors agree fairly well. The GREET N2O factor is higher than the API factor, but the GREET CH4 factor is lower than the API factor. We have elected not to modify the GREET emission factors for this analysis.

General Crude Recovery Comments

Suncor:

The energy efficiency shown on slides 30 & 31 are confusing.

Please see discussion of GREET process efficiency at the beginning of this document.

Unknown:

TIAX compares calculated efficiencies to GREET values but not to GHGenius values.

TIAX will compare values to both GREET and GHGenius default values.

Suncor:

We export 190 MW of electricity to the grid. How is this accounted for?

For this operation, the process fuel consumption would be higher than a non-electricity exporter, but a credit would be given equal to the emissions associated with generating 190MW. The offset emissions assumed would be consistent with the grid mix that the exported electricity is displacing. If we have time, it would be nice to build an algorithm in GREET allowing the user to adjust the amount of cogen done (onsite fuel consumption would increase and exports would *increase). Alternatively, we will address this by running cases that bracket the range (time and budget allowing). As mentioned above, the grid mix that is assumed for the credit will be clearly stated (Alberta mix, National mix, natural gas combined cycle, etc).*

Ontario Ministry of Energy:

Oil Sands operations run continuously. Although Alberta is a net importer, in off-peak hours, Alberta exports electricity to British Columbia. This would displace BC hydro generation. However, by exporting to BC in off-peak hours, Alberta can import more hydro from BC in peak hours. Is TIAX considering imports/exports in determining the electricity credit?

The grid mix used for electricity credit is always a complicated issue. In an ideal world, a dispatch model would need to be run to capture what the net effect is of adding a generating unit at an upgrader. This is beyond the scope of the project, and as you point out reduced hydro use at night will result in increased hydro use in the daytime, possibly making it a wash. TIAX plans to use the Alberta annual average grid mix reflecting total consumption by fuel type (including imports and exports).

LENEF Consulting:

I do not see any factors or information on pipelining based emissions.

TIAX will use the GREET default values for pipeline transport energy consumption. Pipeline transport energy and emissions are a relatively small part of the total.

LENEF Consulting:

I believe that comparisons of CO2 lifecycle emissions between crude sources should be based on a "unit of liquid refinery products" produced not at the "unit of crude" level.

TIAX agrees – the final results will be in g/mmBtu gasoline and g/mmBtu diesel.

Suncor:

Although the TTW portion of the analysis will be a constant added to each crude, it is important for policy-makers and the public to understand the relative CO2 contribution during fuel combustion in the engine.

TIAX agrees – the WTT portion of the WTW emissions is small. While not all of the results will be presented as WTW, we will be sure to emphasize this point.

Laricina Energy:

The characterization of conventional crudes is not as rigorous as for Canadian oil sands production. A more rigorous evaluation of only some crude oils could result in a higher GHG emission footprint compared to those with less rigorous evaluations, leading policy makers to invoke less effective policy and regulation. I would recommend that experts for each country or crude oil be engaged to help characterize each crude oil.

We do not agree that the oil sands characterization is more rigorous than the conventional crude characterization. Moreover, a more rigorous evaluation does not necessarily result in higher GHG emissions. This project is not meant to be the final statement on crude oil recovery emissions for each country. It is simply meant to be an improvement over what has been utilized to date in GREET (U.S. average crude recovery and refining energy and emissions).

Laricina Energy:

It is not apparent what the final deliverable will look like. I assume that an evaluation of the emissions from wells-to-wheels for each crude and refining location combination will be part of the final deliverable. In addition, I would also suggest that the average emissions for production from each country be determined. Developing such modeling capabilities will serve to enable the evaluation of changing crude oil properties, production mixes and refining markets over time in the future.

The final deliverable will provide for each crude/refining region option WTT and WTW energy consumption and GHG emissions. In addition, the composite results will be broken down into components (recovery, crude transport, refining, finished fuel transport). Finally, sensitivity and uncertainty analyses will be done so that error bars can be shown on the plots.

Comments on Refinery Modeling

Ivanhoe Energy:

We encourage the "Fix" case rather than the "Float case" because we are trying to count carbon and not attempting to optimize the refinery. We suggest that you assume the market needs be met for all crudes and vary the crude rates to meet the production of refined products to the greatest extent possible.

This question may pertain to the refinery modeling results to be submitted to the forthcoming GREET-based lifecycle analysis. We expect that the life-cycle analysis will use results from the Fix cases. However, the question calls for a broader answer.

The energy used in refining a given crude oil is not an immutable attribute of the crude oil; it depends not only on the crude's properties but also, to some degree, on the specific refining environment in which the crude is processed. All of our estimates of refinery energy use for specified crudes are in fact estimates of the change in refinery energy use resulting from the optimal introduction of a specified crude into a baseline crude slate being processed in a particular refining configuration. Whether or not that optimal introduction would involve a change in product out-turns would depend on market conditions at the time – which is unknowable now.

We did not suggest that the results of either the Fix cases or the Float cases be taken as the preferred estimates of refinery energy use. Rather, we presented both sets of results to indicate the sensitivity of our results (and of refinery energy use estimates in general) to assumptions regarding the way in which refining sector would accommodate a change in crude slate.

Recognize that we are "counting carbon" in both sets of cases; but under different premises regarding the refining sector's behavior. In practice, each refiner indeed seeks to "optimize the refinery" every day; if that means adjusting the product slate to make the best economic use of a specific crude slate, so be it.

LENEF Consulting:

There is no obvious allowance for iso-butane purchases. I have found that light-med conventional crudes need 2% by vol purchased isobutane, but a bitumen barrel needs about 7% volume b/c of the high per unit FCCU feed from virgin VGO and the coker.

In our analysis, we recognize iso-butane purchases, but we hold the purchase volume constant for all study crudes as we displace some of the composite crude slate with a like volume of a study crude (e.g., synbit, Escravos, etc.). We do the analysis that way because (1) the substitution volume is small relative to the total regional crude volume, (2) the refinery model uses the flexibility in regional refining operations to meet the specified product slate without increasing purchases of iso-butane or any other non-crude input, and (3) our objective is to estimate, for each study crude, the change in regional refinery energy use resulting from the introduction of a specified volume of the study crude into the regional crude slate.

Item (3) is particularly important. By contrast, Mr. Flint's note seems to imply that his analysis treats refinery energy as an intrinsic property of a study crude, regardless of the refinery setting. I think that his analysis showed large crude-to-crude swings in iso-butane purchases because his refinery model handled only one crude at a time and did not capture sufficient flexibility in refining operations.

Finally, because we hold iso-butane purchases constant from crude to crude, TIAX need not worry about the energy input to field iso-butane production and transport.

LENEF Consulting:

With respect to refinery coke, how is the "clearing market" issue handled in the event of coke make excess to North America demand?

As the question suggests, introducing certain heavy crudes (e.g., Maya, SJV Heavy, Synbit, etc.) into the baseline crude slate leads to production of petroleum coke in excess of the reference case volume (which we estimate from EIA projections of future U.S. refined product demand). We assume in this analysis that the regional refining sectors can dispose of all of the pet coke they produce, in all cases, without regard to price.

Coke is a low-value product, and coke sales constitute only a small share of refinery revenues. Moreover, pet coke is a refinery by-product. Real refineries – and certainly our refinery models – do not produce pet coke on-purpose, nor do they have any direct means of controlling pet coke production without affecting other product rates. In general, refineries tend to price coke as needed to sell their production in the available markets, and they use various means to dispose of coke in excess of what the markets will take. These means can include refinery-based gasification and co-generation, stockpiling, or even paying to have the coke hauled away.

UC Davis:

There is a discrepancy between the timeframes of the crude oil analysis (as recent as possible) and the refinery modeling (2015).

The only aspect of the refinery modeling that reflects the year 2015 is the finished fuel formulations. Current fuel formulations are very close to the 2015 standards. Rather than model an intermediate situation, we have chosen to use 2015 standards as these will remain useful longer. Since the early 90's, formulation standards have been changing almost yearly in the areas of sulfur and compatibility with ethanol for refinery produced gasoline. Although more energy will be required to meet increasingly stringent sulfur regulations, the introduction of larger quantities of ethanol into reformulated gasoline will also reduce the refinery energy necessary to produce the refinery gasoline that will be mixed with ethanol. This is due to the estimated 105+ octane of ethanol and reduced refining necessary to meet the requirements of combined refinery gasoline + octane (reformulated gasoline) of 87 (regular) and 92/93 (premium).

Stakeholder Input II. Phase I Final Presentation

The final presentation for Phase I of this project was held on June 15, 2009 in Calgary, Alberta to provide an opportunity for stakeholders to understand our methodology and findings. The following is a summary of the questions/comments received and TIAX responses.

How good is publicly-available data for conventional crude and oil sands?

We recognize the limitations of using publicly-available data and have attempted to use credible sources. Our data are derived from peer-reviewed, published reports and applications reviewed by the EUB and AENV. Because applications may be several years old and current operations may differ, oil sands operators were given the opportunity to comment on our GREET inputs.

Did TIAX consider emissions associated with diluent production?

Yes, diluent production emissions were considered, along with other upstream energy requirements.

Did TIAX distinguish among different SCO qualities?

*Yes, our refining analysis examined the properties of each crude oil. (See API gravity/sulfur graph in **Error! Reference source not found.**.)*

Did TIAX account for upstream emissions, e.g. to produce natural gas used in steam generation?

Yes, one of GREET's main functions is to track upstream emissions, and model inputs were adapted to each specific crude oil pathway.

Were default GREET values used for upstream emissions?

Yes, default emission factors were used, and we specified inputs such as electricity grid mix at the PADD-level for the United States, state/province-level for Alberta and California, and country-level for foreign crude pathways.

Why is a SAGD-dilbit result shown when it is not one of the four selected oil sands pathways?

We list four main oil sands recovery pathways but actually also ran variations of these pathways. The SAGD-dilbit pathway was created by combining SAGD recovery with dilbit transport and refining.

Was there an attempt to "ground truth" recovery emissions from conventional crudes?

No reports on specific processes were available to make this comparison, which was one motivation for conducting this analysis of different crude pathways.

Where did TIAX find the names of the crude oils corresponding to each country?

MathPro matched the crude properties (API gravity/sulfur content) reported for each country to specific, known assays.

How is refinery coke handled?

No energy and non GHG emissions are allocated to coke produced at the refinery since this is not an on-purpose product.

How is refinery LPG handled?

LPG is part of the product slate, listed under the "Other Products" category.

How did TIAX distinguish among different refineries and seasonal differences, e.g. high vs. medium conversion?

We held the refinery slate constant for an annualized average refinery within the refinery region (California, PADD 2, PADD 3).

California refineries seem to be the most inefficient. Is this erroneously taking into account high conversions?

California has a high percentage of gasoline in its product slate in addition to a heavy crude slate, which makes the refineries look less efficient. In this analysis aimed at understanding the emissions of different crude oils, it is more important to compare across different crude oils in the same region rather than the same crude oil in different regions.

Where are the estimated refinery energy use data from?

Section 4 of Appendix D details the sources of refinery energy use data, including the U.S. Department of Energy and the Energy Information Administration.

What is the range of gasoline-to-distillate ratio in the three refining regions?

Diesel is fairly constant across the regions. Gasoline varies and is highest for California.

Where is the graph in slide 28 (estimated refinery energy use) in the TIAX report?

This graph is aggregated from multiple graphs in the report.

Are the SCOs from SAGD and mining different?

Yes, synthetic crude oils from the two pathways are associated with different properties in the analysis. (See API gravity/sulfur graph in ***Error! Reference source not found.****.)*

Does refinery energy use account for and normalize to natural gas and electricity?

Yes, the energy use is reported per barrel of crude oil entering the refinery and includes energy from natural gas and electricity.

How do refineries change to accommodate different crude oils?

The refinery modeling accounts for caps (e.g. hydrogen) that are present for each PADD, and the crude oils and products must conform to what is needed for consumers.

Is unconstrained coke burning allowed in the catalytic cracker?

Yes, coke burning is not constrained. The model accounts from more steam as a result of more coke.

Refineries are not optimized in real operation. Does it make sense to analyze an optimized refinery?

Although real operations may not necessarily be specifically optimized for energy use, they can be expected to be nearly optimized economically. For the purposes of this analysis, optimized refineries offer a way to compare different pathways, since un-optimized refineries have an infinite number of variations to compare, which can lead to misleading results.

TIAX calculates approximately 12 gCO_2e/MJ for the mining pathways, while Suncor and Syncrude have reported 16 and 21 gCO_2e/MJ for their operations. What is the reason for this discrepancy?

Because the Suncor and Syncrude numbers do not include explanations of how these total emissions were derived, it is difficult to pinpoint the reason for this discrepancy. It is possible that these numbers include partial coke use rather than 100% natural gas as in the CNRL Horizon operation which was used to represent the mining pathway.

Are refinery byproducts not allocated to products?

Coke is not considered a product, but other products such as bunker fuel are included in the "Other Products" category.

Did TIAX include non-combustion emission factors?

We included venting and flaring, and non-combustion factors were incorporated into MathPro's emissions.

Is residual oil accounted for?

Our focus was on the lighter end of the product slate, and residual oil was included in the "Other Products" category. Residual oil and other products were held constant, and coke was allowed to float.

Coke was not combusted, so its energy cannot be included in the GREET efficiency calculation.

True, and as such, the SAGD-upgrading process has no coke output in the efficiency calculation.

The treatment of coke in the analysis is not fair to operations that have integrated coke use.

From an emissions standpoint, it is true that internal coke use is penalized because coke has a higher carbon per energy content than the alternative fuel, natural gas.

Gasoline and diesel refining are equivalent today, driven by the ULSD specifications. Gasoline does not take more energy to refine than diesel.

The difference in relative energy is shown by the refinery modeling. The ULSD standard does not increase the refinery energy requirement by a large amount because the hydrogen required is not as much as is needed for hydrocracking.

ULSD from SCO-SAGD should not need much refining and should show the lowest emissions.

While upgrading creates a lighter product, the gains in upgrading do not directly translate into less energy required in refining because upgrading and refining create different molecules.

Dilbit looks better than synbit from an emissions perspective because not all material comes from oil sands (dilbit has condensates).

True, and with limited diluent supply, the incorporation of new elements to the pathway, such as a diluent return pipeline, will change the emissions of the dilbit pathway.

Does CNRL Horizon use cogeneration?

According to CNRL Horizon's March 2003 application to the EUB and AENV, the project has cogeneration capability but will not apply to the EUB to export electricity in its first three phases.

The Christina Lake bitumen heating value in the TIAX report is incorrect and should be the same as that of MacKay River.

The heating value in the draft version of this report was based on the EnCana Christina Lake EUB Supplemental Responses, August 2005. However, as we allowed operators of the representative projects to provide feedback on how the current processes may deviate from the original applications, we have assumed for this final report that the bitumen heating values are the same for Christina Lake and MacKay River, both of which are located in the Athabasca region.