Economic and environmental effects of the FQD on crude oil production from tar sands

Final report
Delft, May 2013

Author(s):
Ab de Buck, Maarten Afman, Bettina Kampman (CE Delft)
Jan van den Berg, Gerd-Jan Otten (Carbon Matters)

Publication Data

Bibliographical data:

Ab de Buck, Maarten Afman, Bettina Kampman (CE Delft)
Jan van den Berg, Gerd-Jan Otten (Carbon Matters)
Economic and environmental effects of the FQD on crude oil production from tar sands
Delft, CE Delft, May 2013

Publication code: 13.4A14.32

CE Delft publications are available from www.cedelft.eu
Commissioned by: European Federation for Transport & Environment.

Further information on this study can be obtained from the contact person, Ab de Buck.

CE Delft
Committed to the Environment
CE Delft is an independent research and consultancy organisation specialised in developing structural and innovative solutions to environmental problems.
CE Delft's solutions are characterised in being politically feasible, technologically sound, economically prudent and socially equitable.

Carbon Matters
Carbon Matters is an independent company advising industrial and (semi)governmental organisations on their energy and CO_2 emission management. The company has a strong background in the process industry. The expertise and core proposition of Carbon Matters is profitable CO_2 reduction, based on the development of effective and achievable sustainability business targets. This proposition is offered through three products:
1. CO_2 Footprint and Benchmark; 2. Profitable Carbon abatement options and quantified business cases and 3. Implementation- or internal audit of the control framework.
The Carbon Matters product base is driven by economics. Proposals for improvement are developed to match current legislative requirements and have flexibility to be adapted in line with future directives (more details: www.carbonmatters.nl).

Contents

Summary

Background and aim of this study

As part of the drive to reduce transport greenhouse gas (GHG) emissions, Article 7a of the revised EU Fuel Quality Directive (FQD) obliges fuel suppliers to reduce the contribution of transportation fuels to GHG emissions by at least 6% by 2020 on a well-to-wheel basis. To this end, the EU is currently developing a methodology to differentiate fossil fuels on the basis of feedstock and GHG emissions. In the FQD draft proposal, diesel produced from tar sands (natural bitumen), for example, has been given a default emission value of 108.5 gCO_2 eq/MJ, while diesel from conventional crude was set at 89.1 gCO_2 eq/MJ. The Commission's proposal is currently undergoing an impact assessment and is expected to be resubmitted to the Council later this year (2013).

In this report we investigate developments in the production of unconventional crudes (natural bitumen) in Canada and Venezuela and exports of (products from) these crudes to the EU. In addition we examine the potential economic and environmental impact of implementing the proposed FQD measures on the production of crudes from tar sands and existing and new tar sand exploration projects.

Current state of production and exploration of unconventional crudes

Three primary production techniques for mining and processing of tar sand crudes can be distinguished: mining, extracting and upgrading; mining and extraction only; and steam-assisted gravity drainage (SAGD). Other techniques are under development. Typical production costs for existing projects vary between 44–52 $/bbl. For newly planned projects, investments range from 32 to 92 M$/bpd capacity, and operational costs (inclusive blending, handling and transport) from 44 to 53 $/bbl[1].

Canadian production developments are bottlenecked by the capacity of export logistics and Canadian tar sands are primarily exported to the US Midwest. Together with other factors (product quality of West Canadian Select (WCS), increased oil production in the US Midwest), this contributes to substantially lower (10-40 $/bbl) market prices for WCS than for WTI (West Texas Intermediate). There is no significant influx of bitumen crudes from Canadian tar sands to Europe. Besides the logistic constraints in North America, a second factor is that there is limited EU refinery capacity for processing these heavy crudes.

Given current and future refinery capacities in the US, Asia and Europe and transport costs, Canadian tar sand crudes will in all likelihood continue to be exported to the US and, if pipeline capacity becomes available, to Asian refineries. However, tar sand-based products (including intermediates such as synthetic crude oil) may find their way to Europe if additional crude pipeline capacity to the US Gulf or Eastern Canada becomes available. Assuming a stable and favourable political climate in Venezuela, the chances of Venezuelan synthetic crudes, intermediates and products coming to Europe are substantially higher.

[1] These costs are exclusive of the costs of decommissioning production facilities.

The impact of lower prices for tar sand crudes - due to differentiation of crude GHG emissions in the FQD

The European oil industry (Europia) has published a study by Wood MacKenzie claiming that implementation of the proposed FQD would result in a net price increase of 2-3 $/bbl for crude oil imported by the EU compared with other markets. As a result, unconventional crudes would be shipped to other markets, which might lead to increased GHG emissions, but without having any impact on production of and investments in unconventional crudes. Furthermore, the EU refining industry would be disadvantaged, increasing the risk of refinery closure, and fuel prices in the EU would increase.
The present study critically addresses the claims of the Wood MacKenzie study. No supporting evidence was found regarding the price increase mentioned, and a review of the crude markets in Canada and US showed that no significant volumes of tar sand crudes are expected to be exported to Europe, independent of FQD directives. As a consequence many of the arguments listed by Wood MacKenzie, like risk for additional crude shuffling and loss of refinery margin eventually resulting in refinery closure could not be validated nor supported. The impact of the price differential on investments and global GHG emission cuts was then investigated in more detail.

Modelling

We have analysed the potential impact of a FQD price differential on the production of tar sand crudes using a dedicated cost model. The starting point of the model is that the FQD will result in a certain reduction of prices of crudes produced from tar sands. For existing projects, the model determines the potential effect of the differential on the basis of marginal production costs, for newly planned projects on the basis of the net present value (NPV) of proposed investments. The model assumes that the investment, production and transport costs of existing and planned projects vary around median values, according to a normal statistical distribution.

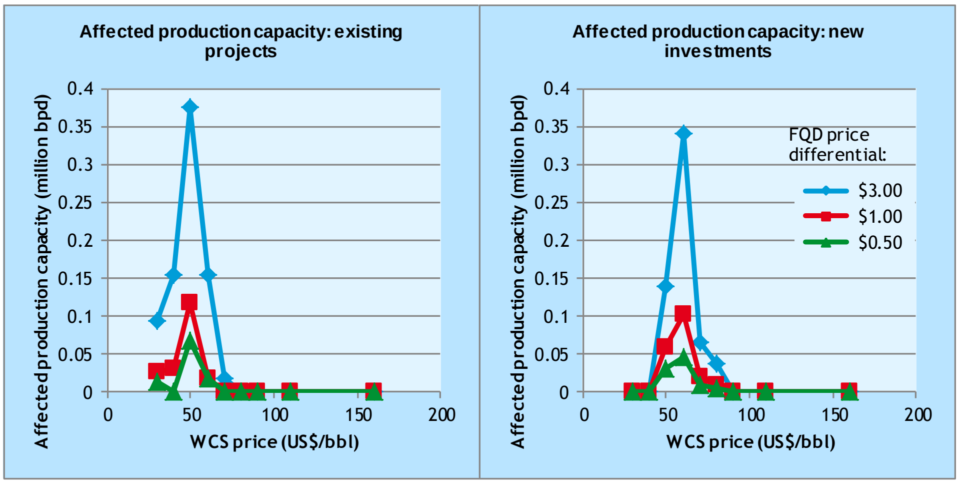
With this model the economic impact of an FQD price differential on tar sand crude projects has been determined for different price levels of WCS.
The difference between projects being pursued with and without an FQD price differential can be considered as the net effect of such a price differential on the production of tar sands in Canada. The model does not consider the production of oil shale, but it can be assumed that the impacts will be similar or even higher, given the higher GHG emissions from oil shale.

Main findings

From the model calculations it can be concluded that a FQD price differential will probably have an impact at WCS price levels ranging from 30–90 $/bbl. This is illustrated in Figure 1. For *existing projects*, the most powerful effect can be observed at WCS oil prices of around 50 $/bbl, with GHG emission savings amounting to 14 Mt CO_2/y at an FQD price differential of 3 €/bbl. This is due to discontinuation of existing projects with negative marginal production costs. For *new projects* the impact amounts to emission savings of 13 Mt CO_2/y at a WCS price of 60 $/bbl, owing to investments not taking place or being postponed.

Combined, for existing and new projects together, the maximum effect would be at a price level at 60 $/bbl, with savings of up to 19 Mt CO_2/y. This overall effect would be substantial and come on top of the total emission reduction effect of the FQD of 60 Mt CO_2/y, which will be achieved mostly by the blending of low-carbon fuels and reduced flaring and venting.

Figure 1 **Modelled impact of FQD price differential for high-carbon crudes on production capacity left: existing projects, right: new investments**



1 Introduction

1.1 Objective of study

The objective of this study is to analyse current and future developments in the production of unconventional crude oils from tar sands and to assess the potential economical and environmental (GHG) impact of a price differential in the FQD on the production of crudes from tar sands.
In the study we investigate developments in the production of tar sands in Canada and Venezuela and consequences for export of (products from) these crudes to European markets. Based on this analysis we investigate the impact that a price differential in the FQD might have on the global transport of crudes from tar sands and the EU refining industry. The potential economic and environmental impact of an FQD price differential on the production of crudes from tar sands are estimated by means of a dedicated cost model.

1.2 Background

Revised FQD: differentiation of GHG emissions of crudes

In response to EU guidelines car manufacturers have started to move on improving car engine efficiencies (with am average emission target of 130 gCO_2/km for 2015 and 95 gCO_2/km for 2020). In a parallel move the focus is now on fuel suppliers.

In this context Article 7a of the revised EU Fuel Quality Directive (FQD) sets an important target, obliging fuel suppliers to reduce the contribution of transportation fuels to greenhouse gas (GHG) emissions by at least 6-10% by 2020 on a well-to-wheel basis. This should ensure estimated annual emission savings of 50 to 60 million tonnes CO_2. To this end the EU has developed a methodology to differentiate fossil fuels on the basis of the type of crude used as feedstock for fuel manufacturing, using default CO_2 values defined per crude type.

The proposed FQD includes implementation of new methodologies to differentiate the CO_2 default values of the various transportation fuels on the EU market, depending on the feedstock (tar sands, oil shale, coal). This is an important issue, since fuel carbon content varies significantly depending on crude type and production method.

The FQD proposal distinguishes different types of non-conventional crudes, the default values of which are listed in Table 1. For example, diesel from natural bitumen has been given a default emission value of 108.5 gCO_2 eq/MJ, while diesel from conventional crude has been set at 89.1 gCO_2 eq/MJ.
In general, crudes from tar sands fall in the category of natural bitumen, as defined in the FQD[2].

[2] Natural bitumen is defined on the basis of its specific physical properties regarding density and viscosity. Natural bitumen is generally defined as exhibiting an API gravity of 10° or less.

The default value for GHG emissions from products from oil shale is higher. Oil shales stem from shale formations containing solid kerogen[3].

Table 1 **Default values of life cycle GHG intensities (g CO_2 eq/MJ)**

	Product placed on the market	Life cycle GHG intensity (g CO_2 eq/MJ)
Conventional crudes	Petrol	87.5
	Diesel/gasoil	89.1
Natural bitumen ('oil sands')	Petrol	107
	Diesel/gasoil	108.5
Oil shale	Petrol	131.3
	Diesel/gasoil	133.7
Coal-to-liquid	Diesel/gasoil	172
Gas-to-liquid	Diesel/gasoil	97

In addition to the CO_2 impact of unconventional crudes, other aspects of the extraction of these crudes are also important (Pembina Institute, 2013). This holds for water consumption, for instance, which is related to the extraction methods applied. These additional aspects are beyond the scope of this study, however.

This GHG intensity differentiation will act as an additional constraint on the selection of crudes and/or blending components for the production of transportation fuels. According to a recent Wood MacKenzie study commissioned by Europia, implementation of the proposed FQD policy will lead to a crude price differential between High Greenhouse Gas Crudes and Low Greenhouse Gas Crudes (Wood MacKenzie, 2012). According to that study this would have adverse effects on global GHG emissions (which would increase, as the oil industry would have to ship its products further afield, to India and China, for example). Also, the EU refining business would be put at a disadvantage vis-à-vis international competition, increasing the ultimate risk of job losses and refinery closure. Following this line of argument, European consumers would pay more for their fuels, while the environment would suffer. However, the Wood MacKenzie study provides only limited evidence to substantiate these conclusions.

In this report we investigate the environmental impact of the proposed FQD on the production of tar sand crudes, taking into account the available capacities for transport and refining of these sand crudes. We take and define a fresh position based on publicly available data and compare and contrast this position with the Wood MacKenzie statements.

We also assess the potential effects of the FQD on the GHG emissions of tar sand crude production by means of a model analysis, using this to evaluate the potential economic impacts of price differentials for tar sand crudes. Based on the calculated economic effects, we determine the effects on the GHG emissions associated with production of tar sand crudes. This exercise is carried out for different price levels, reflecting different possible economic developments in the output from existing and planned projects.

3 Oil shale is defined as any refinery feedstock source situated in a shale formation containing solid kerogen and falling within the definition of oil shale under CN 2714 10 00 outlined in Council Regulation (EEC) No 2658/87.

The focus of this study is on tar sands. However, other unconventional oils such as oil shale, CTL and GTL are also likely to become commercially exploited in the coming years, and the FQD would impact also these developments.

Elements of the study

The study consists of two elements:

1. Evaluation of critical topics for the FQD impact analysis and their potential economic and environmental impact. On this basis the claims of the Wood Mackenzie study (on behalf of Europia) are addressed and reviewed (Annex A).
2. Model calculations to investigate the impact of reduced prices of tar sand crudes on existing projects and investments, and the resulting impact on GHG emissions.

Scope

The basis for this study is the European Commission's draft proposal on FQD implementation dated October 2011. The study focuses on the production of tar sand crudes in Canada and Venezuela, with quantitative information mainly available for Canada. The model calculations are based on production volumes and production prices for tar sands in Canada. The study describes the effects in the year 2020, with an indicative assessment for later years (up to 2030).

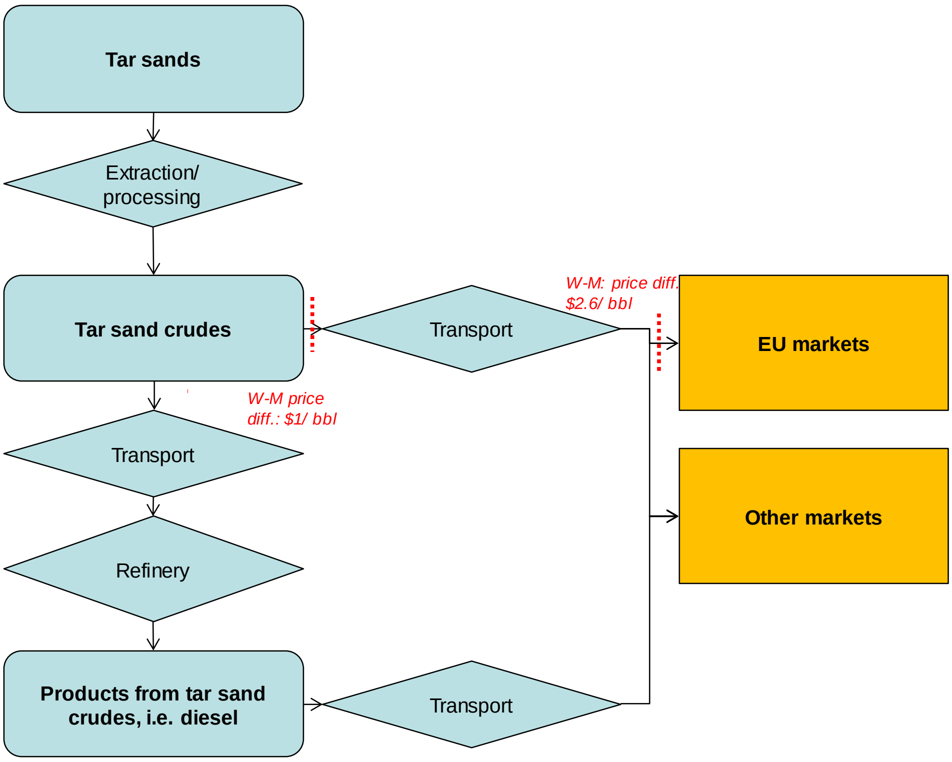
The research is based on publically available literature and data, as well as on interviews with stakeholders and experts such as oil traders, oil industry staff and refining staff directly involved in the topics under consideration.

1.3 The potential impacts of the FQD on prices of unconventional crudes

Implementing the FQD draft proposal may result in an incentive to the oil industry to use the crudes that have a relatively low-carbon intensity: using fuels from high-carbon intensity crudes may require additional measures to meet the GHG reduction target and therefore incur additional costs. This may lead to an increased price differential between conventional and non-conventional crudes.

Figure 2 shows a simplified model of the supply chain of production from tar sands. This includes the production of crudes from tar sands, products (i.e. diesel) from these crudes and transport of crudes and products to EU and other markets.

Figure 2 Simplified scheme of production and export of unconventional crudes to EU and other markets



Wood MacKenzie estimates that crude GHG differentiation in the FQD will result in 2-3 $/bbl price divergence between high-GHG and low-GHG crudes entering the EU markets (Wood MacKenzie, 2012[4]). This value of 2-3 $/bbl is comprised of a price discount of 1 $/bbl for high-GHG crudes produced, e.g. tar sands, and a rise in prices of low-GHG crudes imported to the EU of 1.6$/bbl. The background of these estimates is not given, but the principle behind this effect is quite clear. According to the FQD proposal, suppliers must reduce the GHG emissions in the production chain of their fuels by 6-10%. Extra GHG emissions stemming from production and pre-treatment of unconventional crude will thus have to be compensated by purchasing fuels with a lower GHG footprint, for instance certain low-carbon (bio)fuels, or through investments in mitigation of flaring and venting. These come at a higher price, which will result in a lower market price for unconventional crudes such as from tar sands. The same might be expected for *products* from unconventional crudes that will be exported to EU markets (for instance diesel), since the default GHG emission values of diesel from tar sand crudes (108.5 g CO_2/MJ) are considerably higher than those for conventional crudes (89.1 gCO_2/MJ).

[4] Slide #17 of the sheet presentation.

2 The potential impact of FQD on production, processing and global market of high-carbon crudes

2.1 Developments in sourcing, production and pre-processing unconventional crudes

Tar sand crudes manifest themselves in different guises. Tar sand crudes are referred to as extra heavy crudes based on high energy intensity of production and/or subsequent processing resulting in high-GHG footprint when entering the market. These extra heavy crudes often manifest themselves as high gravity (API< 10)/high viscosity natural hydrocarbon deposits. Current widely traded heavy crudes (API< 22) that are close in properties but slightly less heavy are e.g. Mexican Maja (API 22) and Venezuelan Tia Juana Pesado (API 12) crudes.

The largest known commercially recoverable hydrocarbon reserves outside Saudi Arabia are located in Alberta Canada and Orinoco belt Venezuela[5,6]. These hydrocarbon reserves are of similar geological provenance, composition and present, dependent on the depth of the oil layers, comparable technical mining or production challenges.

Up to 70 meters of depth the Canadian tar sand (or natural bitumen as they are often referred to) are produced through open cast or strip mining. Deeper deposits, as occurring in both Canada and Venezuela, are produced through different and developing techniques involving multiple drilling and steam-assisted production methods (e.g. Steam-Assisted Gravity Drainage or SAGD using two horizontal shafts for bringing in the heat and draining the heated heavy crude). Both production techniques in-situ more profoundly compared to mining, are energy intense in relation to conventional oil production.
In Venezuela only a limited number of European operators are active (Total/Repsol). Depth, reservoir- and ambient temperature facilitate production of essentially in-situ methods (cold production & SAGD)
Production and consumption figures in this section can be put in perspective of a world oil demand of currently 90-100 mbpd. In 2011 US demand was at 20 mbpd and EU demand at 15 mbpd.

---

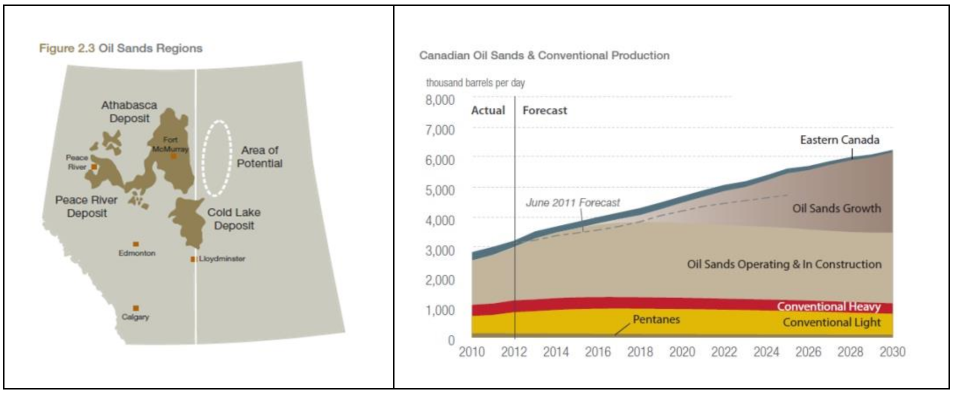
[5] IEA ETSAP Technology Brief P02 – May 2010 – Unconventional Oil & Gas production - www.etsap.org.

[6] API - May 2011 – Canadian Oil Sands.

Canada

Canadian crude production is increasingly dominated by tar sand crudes from Alberta (Figure 3)[7]. Based on current investments and committed investments, provided that marginal production cost stay below market value, the current total Canadian crude oil production will grow to nearly 3.5 mbpd in 2015/2016 compared to over 3 mbpd in 2010. Provided sufficient and free access to (world) markets investments could, according to CAPP, effectuate a production growth to 5-6 mbpd.

Figure 3 Geographical distribution of Canadian heavy crude oil sources and production volume outlook



Venezuela

The Venezuelan heavy crude deposits are located in the Orinoco basin and although of similar quality as the Canadian tar sand crudes are often referred to as extra heavy crude oil (Figure 4). Production challenges are similar to the Canadian tar sands be it that the Venezuelan oil layers are found at greater depth (350-1,000 meter) while the reservoir- and ambient temperatures are significantly higher (around 54˚C)[8,9]. Given the greater depth mainly in-situ techniques are applied. Due to the higher reservoir, and ambient, temperatures, compared to Canada, the crude oil is still mobile to allow for cold production

The political history as well as outlook for Venezuela differs from that for Canada. Renegotiations of oil production contracts during the Chavez administration has delayed but not stopped (western) investments. Specifically to note are the Repsol investments under the Chavez administration and current production in the Caraboco 1 concession area where extra heavy crude production has started at modest levels of some 30kbd rising to 90 kbd in 2014.

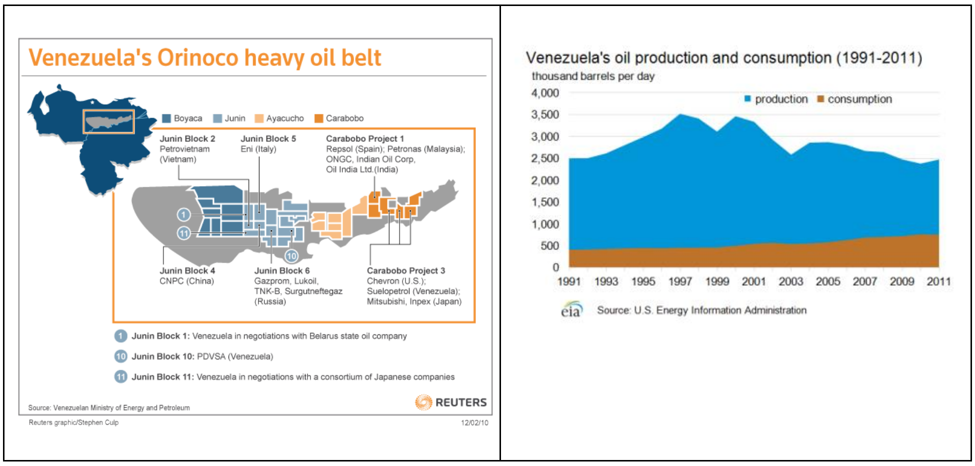
---

7 CERI March 2012 – Canadian Oil Sand Supply Cost and Development projects (2011-2045).

8 CIPC 2001 Dusseault – Comparing Venezuelan and Canadian Heavy Oil and Tar Sands.

9 Petroleum World 2010 – Venezuela Orinoco heavy oil belt – www.petroleumworld.com.

Figure 4 **Geographical distribution of Venezuelan heavy crude oil sources and production volumes**



Apart from unconventional crude deposits in Canada and Venezuela, in the US significant deposits are known in Utah and prepared for 2013 first production (kerogen oil shale). In addition shale oil (fracking) production is ramping based on supplies out of the Bakken and the Eagle ford basin, respectively.

The US crude supply-demand balance is of particular importance given the high proportions of total crude export from Canada, as well as exports from Venezuela routed to the USA. Increasing shale oil (and -gas) production will impact unconventional crude exports from Canada and Venezuela, this due to constraints on supply-demand balance as well as due to competition for pipeline capacity.

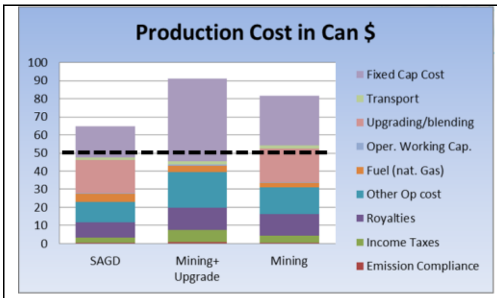
Pre-processing or upgrading

Tar sands whether produced through opencast mining or heat assisted production require pre-treatment prior to transport. Two main types of 'pre-treatment' are relevant in this context 1) high temperature hydrogen pre-processing making synthetic crude or 2) dilution with condensate without changing the physical properties of the constituent elements of either tar sand or condensate . Tar sands/bitumen receive similar treatment whether stemming from surface mining or heat assisted in-situ mining in the separation of sand from the hydrocarbons. Dilution (with condensate is referred to as DilBit whereas synthetic crude(SCO) referred to as SynBit). Both processes enable pipeline transport. Hydrogen pre-treatment (high temperature, high pressure) changes the composition and properties of the crude (intermediate product referred to as SCO) also enables pipeline transport. A wider range of refinery configurations can process this crude compared to diluted tar sand crude.

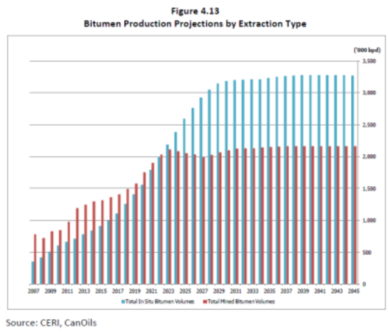
The pre-processing represents additional operational cost and capital cost (Figure 5, expressed as $/bbl bitumen). Whereas existing production facilities have ample capacity for pre-processing, i.e. on-site upgrading of the tar sand bitumen produced to synthetic crude oil, for new investments a risk reward consideration with clear differences between Canada and Venezuela impacts the future production forecasts. In addition, condensate availability for blending may be constrained, as is currently the case for a number of Canadian fields, and may require recirculation or additional imports to meet volume demands.

Currently about 50% of all heavy crudes are upgraded via a pre-processing step, producing SCO (synthetic crude oil). High temperature hydro treatment for tar sand crudes involves substantial and dedicated investments. Financial risk/reward considerations as well as pure economics are anticipated to slow down investments in well based treatment in favour of refinery upgrading facilities.

Figure 5 **Comparison of production cost for different production technologies and expected production volumes using respective techniques**



The dotted line is a proxy for the marginal production costs at some 50 $/bbl.



Source: CERI 1212.

Whereas current production is roughly in balance between mining and in-situ, the future production balance in Canada appears to shift towards heat assisted in-situ production. This due to an advantage in cost profiles on one hand and due to the fact that deeper layers are brought to production on the other. Current *marginal* production costs would appear to be close to Can 50 $/bbl. (exchange rate Can$-US$ 0.97). Transport referred to in Figure 5 is Canadian field transport over distances of up to 300 km. Costs for pipeline and or railroad transport to export facilities, US Midwest or even Gulf Coast are additional and estimated at 7-30 US$/bbl for pipeline and railroad transport, respectively. Note that the shift from mining to in-situ production will also aggravate the CO_2 intensity of production from some 35 to 90 kg CO_2 per barrel (source Pembina).

Trading Values Canadian Crude

Crude oils are traded in US$ differential relative to so called marker crudes like WTI and Brent. Crude quality in relation to required products dictates under most circumstances the differential with the marker crude and hence the value of the crude traded. Transportation costs, either for pipeline of sea bound, although of importance, are seldom restrictive in terms of production economics.

Canadian Crude West Canadian Select (WCS) is currently traded at high negative differential to the marker crudes (see Figure 6)[10,11,12]. These differentials are higher than based on crude quality alone can be expected. The current shortage of pipeline transportation capacity from the US Midwest to the US Gulf Coast causes an oversupply in the Midwest compared to refining conversion capacity with significant negative price/trading differential

---

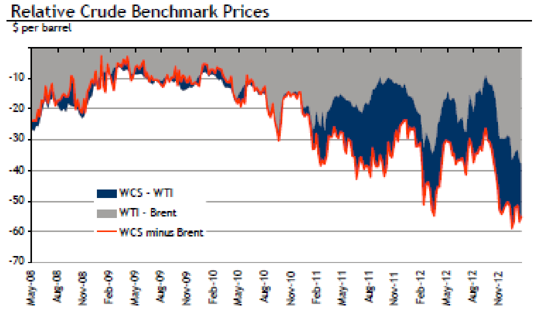
10 RBC January 2013 - Macroeconomic impact of the WCS/WTI/Brent crude oil price differentials.

11 Allen 2013 – Bitumen deep discount deception and Canada’s pipeline mania.

12 CAPP 2012 – Crude Oil: Forecast, Markets & Pipelines.

consequences for Canadian tar sand crudes (see Paragraph 2.3).
Also alternative export routes to e.g. the Canadian West Coast are constrained in capacity. Figure 6 shows the development of the prices of WCS, WTI and Brent. Current marginal production costs for WCS are close to traded values.

Figure 6 **Development of the WCS-WTI-Brent spread during 2008-2012**



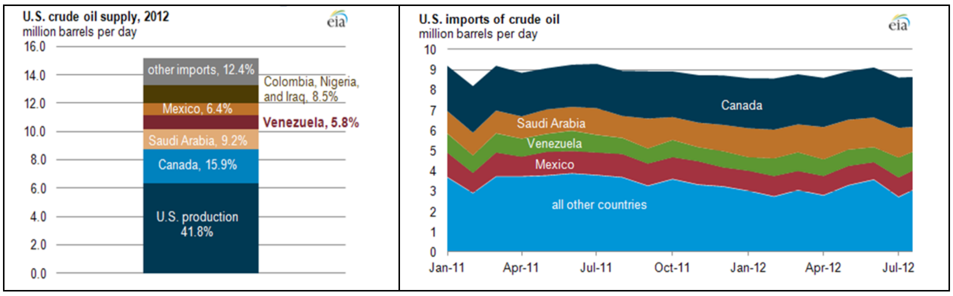
Since 2010 the WTI/Brent spread reversed and opened to $ 10-30. WCS trades at $ 10-20 under WTI. With Brent trading in the $ 95-110 range WCS changes hands at around $ 60/bbl. When compared to marginal current and anticipated future marginal costs this does not leave much room to manoeuvre.
The $ 20-50 price differential is to be compared to the potential price differential stemming from the introduction of the FQD.

The current negative price differentials are extremely large, historically seen. In addition Canadian crude competes with growing US domestic production for pipeline capacity. All in all pipeline capacity constitutes a major impact on relative and absolute Canadian crude prices at this point in time.

2.2 Logistics for transportation of unconventional crudes by pipeline and/or rail and impact on US and global crude markets

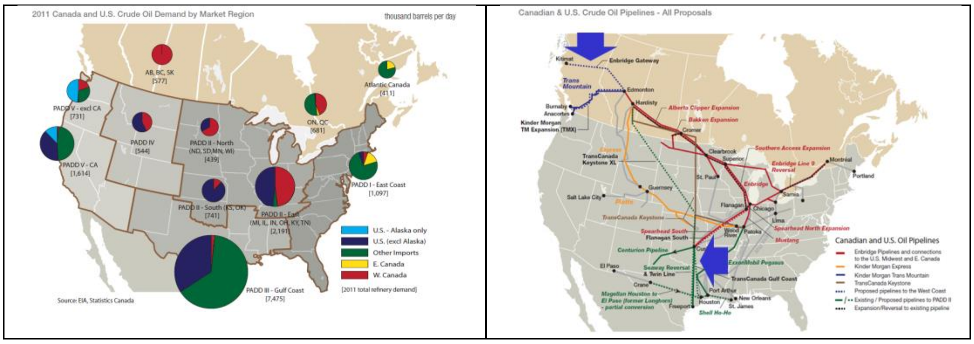
Of the Canadian crude production roughly 1/3 is destined for domestic markets (880.000 b/d) and over 2/3 (2 mil b/d) is exported.
The vast majority (>90%) is exported to the US Midwest. For the US crude consumption the Canadian imports represent 16% (Figure 7). The US and Canada are important trading partners in this respect with an uncomfortable high dependence on the US for Canadian exports.

Figure 7 **Sourcing of US crude imports**



Pipeline and rail transport are currently the main available transport options for Canadian crudes. Pipeline capacity capable of transporting West Canadian crude is referred to as 2,3 mil b/d. This is enough for 2012 production capacity, but increasingly US domestic production is competing for space. The lack of sufficient pipeline transport capacity from the Midwest/Cushing to the Gulf Coast creates oversupply in the Midwest, described in Paragraph 2.2 making the pipeline transportation capacity at least partly responsible for the unfavourable crude price differential as applicable today for Canadian crudes.

Figure 8 **Sourcing of regional US crude imports and US pipeline structure as basis for crude distribution between Canada and US Midwest and Gulf Coast**



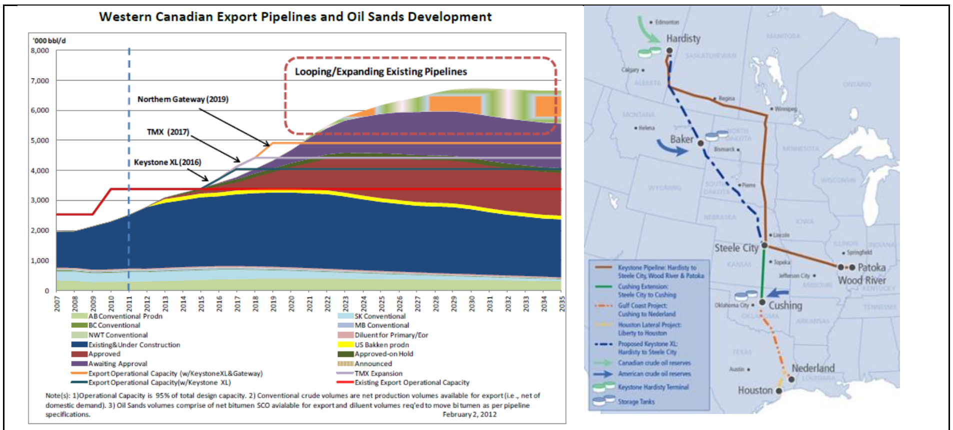
Export pipelines to Canadian West Coast British Columbia and potential export facilities are strongly opposed by First Nations and British Columbians and are unlikely to be built in the near future.

With the pipeline capacity increase from Cushing southwards underway, the Gulf Coast refineries, specifically suitable for product export may by that time be in a much improved position to export tar sand-based products. Venezuelan tar sands are currently finding their way to (Venezuelan owned) Gulf Coast refineries. Any increase in production there is dependent on further investments in the Orinoco basin. Another important development is the US domestic production of shale oil, which may reach 2 Mb/d production in 2013 (according to oil industry expert). US Bakken based shale oil may well be competing for the same pipeline transportation capacity as Canadian crude. This development may on the one hand assist in pipeline capacity expansion approvals but with growing production over time could also pose a threat to back out Canadian crudes.
Although no crude exports out of the US are allowed at this point in time, refined products based on tar sand crudes or lightly treated tar sand crudes called intermediates are already finding their way to export markets.

The pipeline extension from Cushing southwards as well as the Seaway pipeline, connecting Cushing to the Gulf Coast area are currently under construction, together representing 900 kbpd additional pipeline capacity. The Keystone XL pipeline (Figure 9), however, connecting the Alberta tar sands mining areas with the Midwest and Cushing area and further South has been delayed due to inadequate environmental assessment , political escalation in the US Congress. The State Department has approved the Keystone XL pipeline early 2013. Rail transport may and does represent a limited substitute short term but additional costs are significant. Pipeline/rail transport adds $ 7-30 to the marginal cost of tar sand production depending on distance and transport mode.

The delay of the Keystone XL pipeline expansion prevented Canadian crudes, so far, to reach a significant (export) market for Canadian crude in the form of petroleum products being exported from a substantial complex refining capacity capable of converting Canadian crude.

Figure 9 Contribution of individual pipeline projects to total Canadian export capacity for unconventional crudes

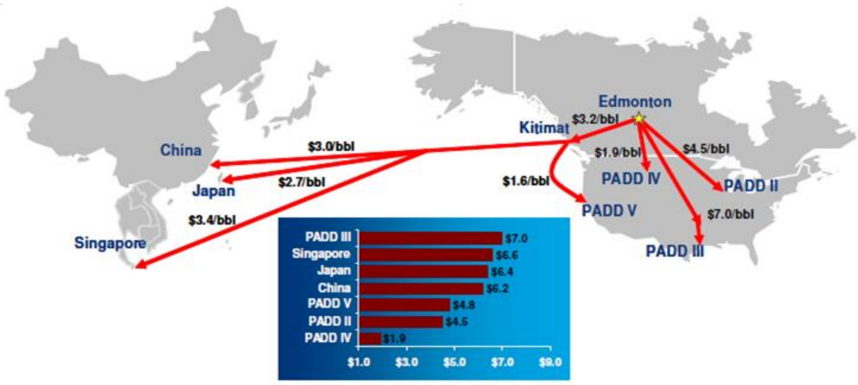


Source: CERI

Canadian Crude production faces logistic and linked pricing/margin constraints.

The lack of US and Canadian infrastructure prevents/delays Canadian crude/ products export in particular to the US Gulf Coast area. Consequentially, in the current situation, this may prevent tar sand-based diesel or other distillate products to find their way to the EU.

Figure 10 Potential transportation routes and rates for Canadian heavy crudes



Source: Wood Mackenzie 2011 – Netback impact analysis canadian heavy crude export

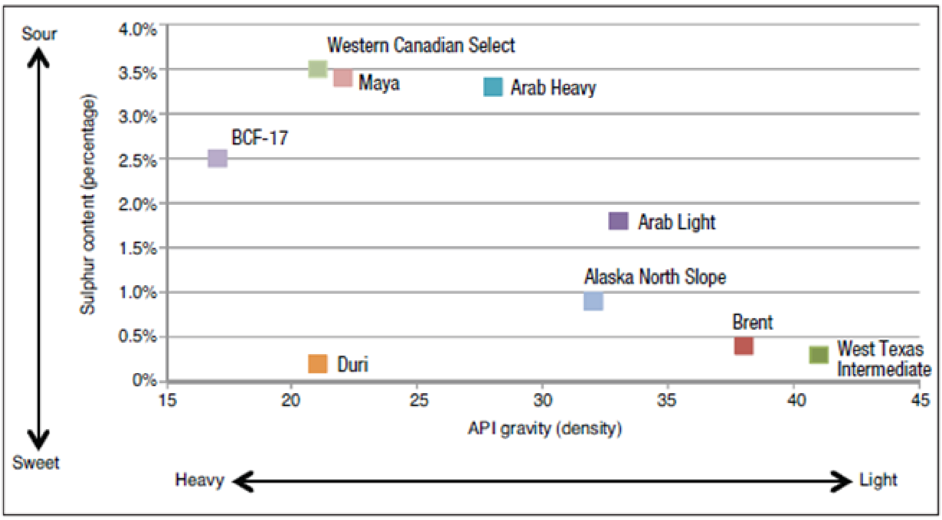
As an alternative, the Canadian government and the tar sand industry is currently working on options to increase pipeline capacity to the West Coast for export to the Pacific/Asian basin (Figure 10)[13]. As will be shown in Paragraph 2.4 this is very much supported and stimulated by market demand (India and China) and available, or new developed, complex refinery capacity on heavy crude conversion able to accommodate such crude volumes and qualities. However widespread public, opposition is causing much delay.

Another potential development is the conversion of a gas pipeline capable of carrying 500,000-1 mbpd from Alberta to the Canadian East Coast.
Given full attention and priority, this option could be operational by 2016.
If materialised, this export option could well enable unconventional crude exports to Europe. Expected crude volumes, other then SCO type, will remain small since EU refineries are not equipped for l tar sand crudes.

2.3 Refining capabilities for processing Diluted Bitumen (DilBit/SynBit) and Synthetic Crude Oils (SCO) ex Canadian tar sand crudes

As described above tar sand crudes represent a crude type at the very end of heaviness when comparing different crude types as currently produced and traded. Figure 11 shows the WCS blend in its extreme position in terms of API gravity and sulphur content when compared to reference crudes like Brent, WTI or Arab Light/Arab Heavy[14].

Figure 11 Density and sulphur content of crude oils



Univ Calgary 2013 – Pacific basin heavy oil refing capacity

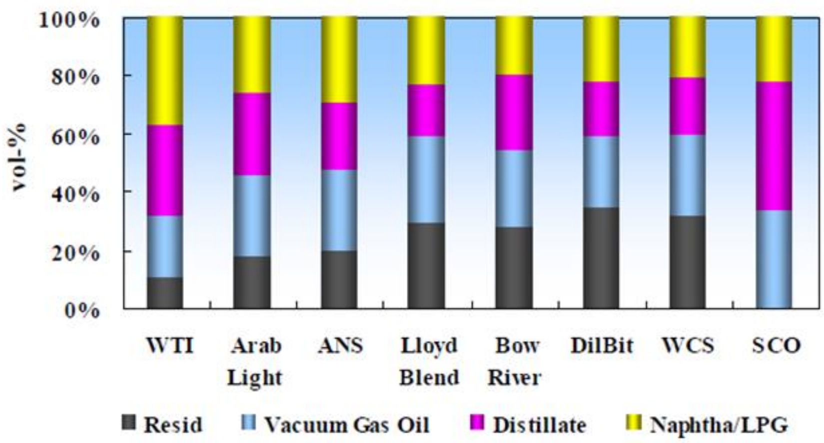
[13] Wood Mackenzie, 2011 - Netback Impact analysis of Canadian West Coast export capacity.

[14] University Calgary, Hackett et al., 2013 - Pacific Basin heavy oil refining capacity.

This difference in density, and related viscosity, translates in different residue yields when conventional distillation is applied to the various crude types. Figure 12 shows how naphtha and distillate contents vary vis-à-vis resid content when comparing current reference crudes like WTI and Arab Light with tar sand crudes like ANS and Bow River or the WCS blend (WCS represents a Canadian standard grade composed of 19 heavy and tar sand crudes representative for Canadian crude quality)[15].

Although diluted with condensate for transportation purposes DilBit retains properties in line with natural tar sand bitumen as seen from a processing or refining perspective. The same holds for SynBit, where the bitumen is diluted with synthetic crude instead of condensate. SCO, which is the product of an on-site upgrading using high temperature, high pressure hydro processing, shows an entirely different composition in that all resid components have been cracked and/or hydrogenated such that an crude like material is produced that can be processed in a wide range of refinery configurations.

Figure 12 Comparison crude composition

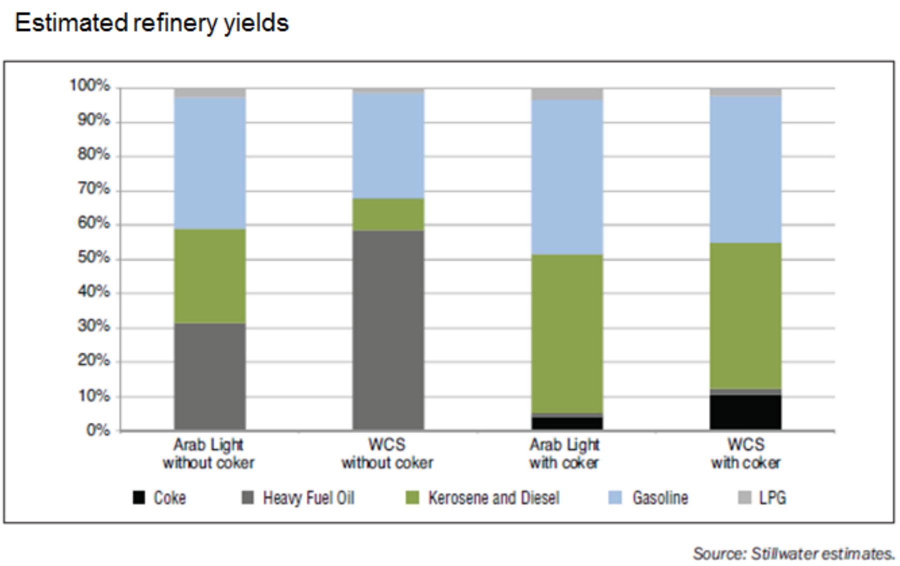


Source: UOP 2006 – Brierley et.al.; Changing refinery configurations for heavy sybthetic crude processing

When processing tar sand crudes or bitumen in relative simple refinery configurations, i.e. distillation with upgrading facilities, a high percentage of heavy fuel oil is produced, leaving limited potential for additional margin stemming from upgrading to more valuable fractions like naphtha and middle distillates. Figure 13 shows that up to 60% of the base material can be left in low value heavy fuel oils. Heavy conversion capacity, like coking, residue cat cracking or hydrocracking, is required to convert the heavy fraction into valuable middle distillates.

[15] Brierley UOP, 2006 – Changing refinery configuration for heavy and synthetic crude processing.

Figure 13 Yield structure dependent on refinery configuration



Source: Univ Calgary 2013 – Pacific basin heavy oil refing capacity

Where SCO can be processed in a wide range of refinery configurations, processing of any DilBit or SynBit crude stream required complex refineries with, amongst others, Delayed Coker Unit (DCU) for upgrading of the heavy components.

When analysing global refinery capacity[16], as currently installed, we find that most of the heavy and medium conversion units are found in primarily the US and, at some distance, in Asia Pacific (Figure 14). European refineries are well equipped for sour crudes and middle distillate upgrading but to a far lesser extent for heavy crude upgrading.

This analysis shows that for export of Canadian tar sand crudes as DilBit/Synbit the US market is the primary outlet (Gulf Coast & Midwest), at some distance followed by the Asian refineries. This picture is further reinforced when we take a look at the 2011-2017 future outlook on global refining construction planning (Figure 15). Clear is that most of the distillation capacity is planned for Asia/Pacific, in particular China and India. The for Canadian crudes relevant heavy conversion facilities, however, are essentially planned for the US, Central & South America and Asia/Pacific. Please note that for tar sand crude conversion the coker units (red blocks in Figure 15) are of prime importance.

This picture shows that for future outlet of Canadian, and eventually Venezuelan, heavy crudes Europe will for the time being not play a role of any significance. The target for additional export will be entirely focused on the Asia/Pacific Basin. In addition, more detailed analyses of required capacities to be able to absorb future volumes of Canadian heavy crudes show that the additional capacity, planned for the Pacific/Asian basin, will be sufficient to absorb the additional future production volumes.

---

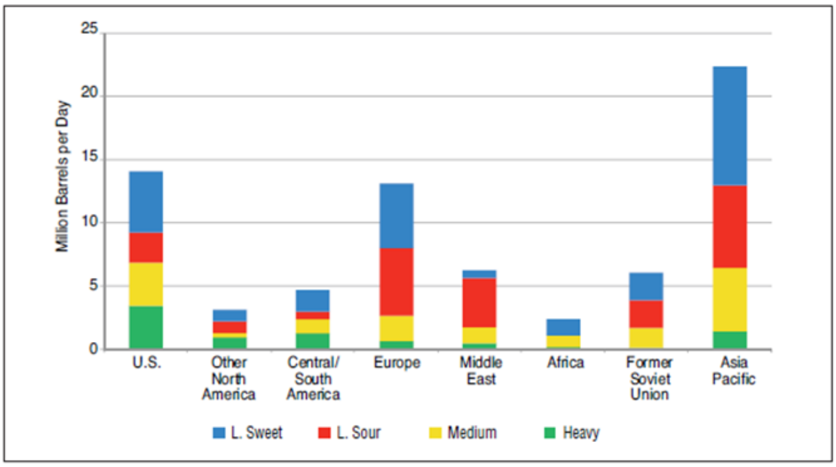
[16] Westfall, 2011 – Midstream Summit Houston 2011 – The oil refinery buildout.

With respect to crude competition for European refiners it is concluded that other than SCO type of crude, no tar sand crudes in the form of DilBit or SynBit are likely to be e exported to Europe in the time to come. Any regulation like FQD will thus not have any impact in that direction.

A different story holds for SCO, be it that the relative contribution of this type of crude is expected to shrink due to high cost levels involved in the pre-processing. More important is the potential export of refined products, in particular middle distillates. Specifically for middle distillate range of products the European market shows a still growing demand which will potentially stimulate import of middles distillates ex heavy Canadian crudes following appropriate processing and upgrading in complex refineries in the US.

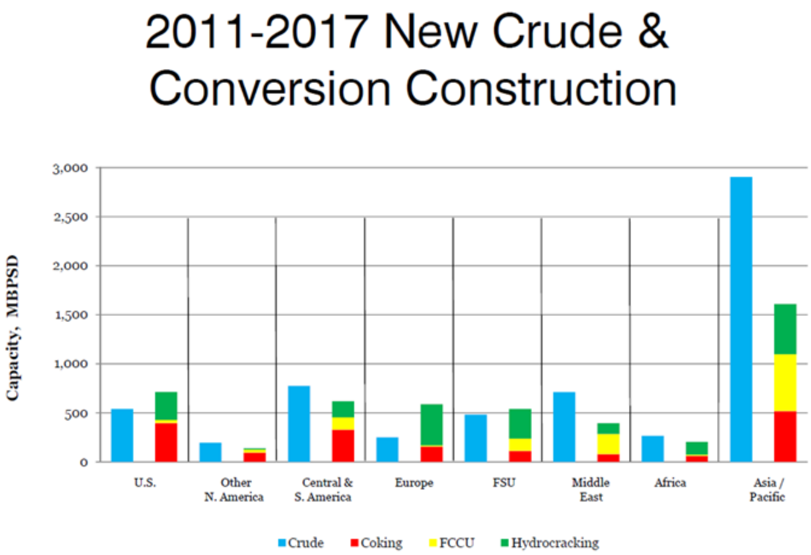
Based on this analysis, the statements in the Wood MacKenzie study concerning the potential impact of the FQD are discussed in Annex A.

Figure 14 World refining capacity by grade (2011)



Source: Lynn Westfall, "The Oil Refinery Buildout," Turner, Mason and Company. Presented at the Midstream Summit, Houston, Texas (March 2, 2011).

Figure 15 Outlook on new construction planning for global refining



Source: Westfall 2011 – Turner, Mason & Company, Midstream Summit, Houston, March 2011

2.4 Impact of development of Venezuelan (and other) tar sand crude sources on US and global crude markets

Where the logistic picture clearly pushes for export of the Canadian crudes to the Asia/Pacific Basin the future Venezuelan heavy crudes might be preferably and more easily available for the European refineries.

The situation for Venezuelan crudes is somewhat different. Currently Venezuela has some 700,000 bpd internal consumption and nearly 2 mbpd export of which only 40% is targeting the US. Caribbean export represents >30%. Total Venezuelan crude production in 2012 was 2,8 mbpd, of which some 700 kbpd heavy crude. These numbers are expected top grow to 3,35 mbpd total crude production (IHS CERA) in 2020 of which 1,4 mbpd heavy crude (IEA).
These numbers clearly stimulate a search for new outlets, potentially via US refineries in the Gulf area, for product export to EU markets.

For potential future tar sand crude production in Venezuela this conclusion is even stronger. Given anticipated lower production cost, proximity to the Atlantic coast, easing restrictions on foreign investments and capital repatriation in Venezuela the chances for Venezuelan tar sand crudes (or derived products) to find their way to Europe are higher. In Figure 16 an overview is given of recent and on-going investment projects on the development of the Venezuelan heavy crude fields in the Orinoco Belt[17].

Figure 16 **Current investments in Venezuelan tar sand projects**

Existing and planned Orinoco Belt projects

Grouping	Project	Actual/ planned Startup date	Current/ projected heavy crude production	Partners
Active Projects	Petroanzoategui (Petrozuata)	1998	107,000	PdVSA (100)%
	Petromonagas (Cerro Negro)	1999	104,730	PdVSA (83.34%), BP* (16.66%)
	Petrocedeno (Sincor)	2000	144,000	PdVSA (60%), Total (30.3%), Statoil (9.7%)
	Petropiar (Hamaca)	2001	131,100	PdVSA (70%), Chevron (30%)
Bilateral Agreements	Junin-2	2012	200,000	PDVSA (60%), PetroVietnam(40%)
	Junin-4	2012	400,000	PDVSA (60%), CNPC (40%)
	Junin-5	2013	240,000	PDVSA (60%), Eni (40%)
	Junin-6	2014	450,000	PDVSA (60%), Russian Consortium (40%)
Carabobo Bid Round	Carabobo-1	2013	400,000	PDVSA (60%), Indian Consortium (18%), Petronas (11%), Repsol YPF (11%)
	Carabobo-3	2013	400,000	PDVSA (60%), Chevron (34%), Japanese Consortium (5%), Suelopetrol (1%)

Sources: PdVSA, Global Insight, Wood Mackenzie
**BP has agreed to sell their share to TNK-BP*

17 EIA, 2012 – Venezuela country update Oct. 2012.

At present, most oil produced from the Orinoco Belt is diluted at the surface and transported by pipeline to the North East coast of Venezuela for upgrading in the Caribbean or Venezuela owned treatment capacity in the US Gulf. New projects include a requirement of building upgrading facilities, typically on the Northeast coast. This creates a different picture for the Venezuelan extra heavy crudes, when compared to the Canadian ones, Most of the extra heavy crudes are exported after some upgrading or dilution.. Cost can be as low as one-third of the cost of Canadian Bitumen from SAGD. This predicts costs as low as 16 $/bbl for bitumen. Upgrading bitumen to SCO of API 39°cost an additional 32 $/bbl which brings in a total cost of 48 $/bbl for synthetic crude oil, ready for export[18].

E.g. Repsol is participating in crude production and capable of processing tar sands in Spain. The respective project (see Figure 16) is currently producing 30 kbpd, rising to 90 kbpd in 2013 and eventually to 400 kbpd when coming to full development.

2.5 Outlook beyond 2030

With conventional oil reserves in decline and production possibly well beyond its peak by 2020, globally the share of unconventional crudes and products are bound to go up. Unconventionals here, refer to tar sand, shale oil, gas to liquid and potentially also coal to liquid and gas hydrates where by that time technology will have developed to tap into the substantial reserves available. Indigenous European production potential of 'unconventionals' would appear to be limited and in case no substantial energy efficiency and or renewable energy developments materialise these unconventional crudes will find their way to the European market possibly in the form of intermediates and products rather than as crude.

2.6 Conclusions

Currently no Canadian tar sands find their way into Europe in any significant way and are not likely to come to the EU either, this based on logistic constraints in North America and refinery capability of processing these heavy crudes on European side.

In view of current and future refinery capabilities in US, Asia and Europe it is to be expected that Canadian tar sand crudes are most likely continued to be exported to US and, once pipeline capacity is available, to Asian refineries.

Provided additional crude pipeline capacity to the US Gulf becomes available and product (diesel-gasoline) imbalances between the EU and the US continue tar sand crude based products may find their way to Europe. The same holds potentially for intermediates or synthetic crude oils, produced via upgrading of heavy crudes.

Assuming a stable and favourable political climate in Venezuela the chances of Venezuelan synthetic crudes, intermediates and products coming to Europe are substantially bigger.

---

18 World Energy Council, 2010 – Natural Bitumen and Extra-Heavy oil.

3 Modelling analysis

3.1 Introduction

The objective of the modelling analysis is a (semi-)quantitative assessment of the potential impact of the 6% emission reduction obligation in the FQD on GHG emissions of production of tar sands crudes through a modelling exercise.

The modelling exercise evaluates the effect of changes of operating margin (marginal revenue for an oil field) on the amount of production from oil sands and the amount of new fields taken into development, using a 1st order investment model.

The following input data is used:
- Production volumes and expected production capacity additions 2012-2020 for Canadian tar sands crudes.
- Expected production capacity additions 2020-2030 for tar sands crudes from Canadian oil sands.
- Effect of the FQD emission reduction obligation on operating margins in 2020 and in the period 2020-2030 (For the FQD induced price differential some typical values have been used, including those put forward in the Wood MacKenzie study, and the expectations of the effect in the present situation (as described in Paragraph 2.1).
- WCS (West Canadian Select) and SCO (Synthetic Crude Oil) prices.
  The model calculations are carried out for different price levels of WCS and SCO, reflecting both the present situation (in which price levels of WCS and also SCO are substantial lower than those of WTI and Brent, due to constraints in transport and refining capacity), as well as potential future developments in which products of tar sands crudes can be exported to global markets.
- For modelling the investments, a 1st order investment model is used.
  A first-order model means that only direct effects are included. Effects on operating margins are evaluated and indirect/rebound effects are not in the model. In reality, an investor can decide to operate at a loss for some time, if he expects that conditions will improve. Such behaviour is not in this modelling exercise.

The modelling approach assumes that projects, production costs, investment costs and so on follow the statistical normal distribution.

3.2 Development of the scenarios

In the modelling analysis, two scenarios (cases) are compared with one another to determine the potential ‘FQD effect’:
- Baseline: no FQD price effect;
- FQD scenario: price effect on overseas crude prices due to differentiation in GHG emissions of crudes.

The first scenario sketches a situation in without an effect of the FQD. This can either be caused by the definition of the FQD (i.e. the directive does not differentiate between the GHG emissions of crudes in the supply chain), or a market situation in which other factors are dominant and the FQD does not result in a price effect on tar sands crudes (i.e.: due to constraints in transport and refining capacity, tar sands crude products cannot be exported to EU markets). This is the baseline scenario.

The second scenario is a scenario in which the FQD does differentiate between GHG emissions of crudes, and results in a price differential for tar sands crudes and products of tar sands crudes. For this second scenario, we have assumed three price differentials: 0.5 $/bbl, 1 $/bbl and 3 $/bbl. The second value is based on the suggested upstream impact in the Wood Mackenzie study, commissioned by Europia. As the potential price effects of the FQD are highly uncertain, in addition to this value also two options have been modelled representing a lower and a higher price effect, since we want to see how effects turn out at those changed price levels[19].

The scenarios with and without a FQD price effect are evaluated on production volumes of existing projects and the amount of investments in new projects. For production from existing oil sand fields, the production is assumed to halt if marginal net revenue is negative, as determined by the operational margin. For new investments, it is assumed they won't take place if the business case is unfavourable, as determined by the net present value of the project. This is a simplification of reality: an investor can decide to operate at a loss for some time, if he expects that conditions will improve at a later point in time. Such behaviour is not in this modelling exercise[20].

The differences between the two scenarios are evaluated, and considered as the net potential effect of the FQD. The assumption when calculating carbon savings is that reduced tar sands production is matched by increased conventional production. Carbon savings are then calculated as the difference between avoided tar sands production and increased conventional production.

3.3 Model input data

The model needs the following input data, per production type:
- production capacities by 2020 ('existing production');
- expected capacity additions 2020-2030;
- marginal production costs of existing production;
- operational costs of expected capacity additions;
- upgrading, handling and transport costs for expected capacity additions.

[19] The determination of the precise future price effects is subject to debate, and beyond the goal of this study. A value of half the value calculated by Wood Mackenzie and three times their value will give a satisfying range to assess possible FQD effects.

[20] This means that this cannot be modelled, using techniques such as Agent-Based Modelling, the adaptive and dynamic behaviour of individual investors can be modelled in complex systems.

The following types of oil sands production are included in the model:

Table 2 **Types of production incorporated in the model**

Types of production	Output
In-situ: SAGD, excl. integrated upgrading (Bitumen)	Bitumen After blending/upgrading: dilbit, synbit, etc.
Mining with integrated upgrading (SCO)	Synthetic crude oil
Mining excluding integrated upgrading (Bitumen)	Bitumen After blending/upgrading: dilbit, synbit, etc.

For both main types of extraction (mining and in-situ), in reality a number of types of extraction technologies are available. For in-situ steam-assisted gravity drainage (SAGD) and cyclic steam stimulation are the dominant types. From the first type good data on production costs was available, which is why this was chosen. For mining, we both include production with integrated upgrading and production with external blending/upgrading.

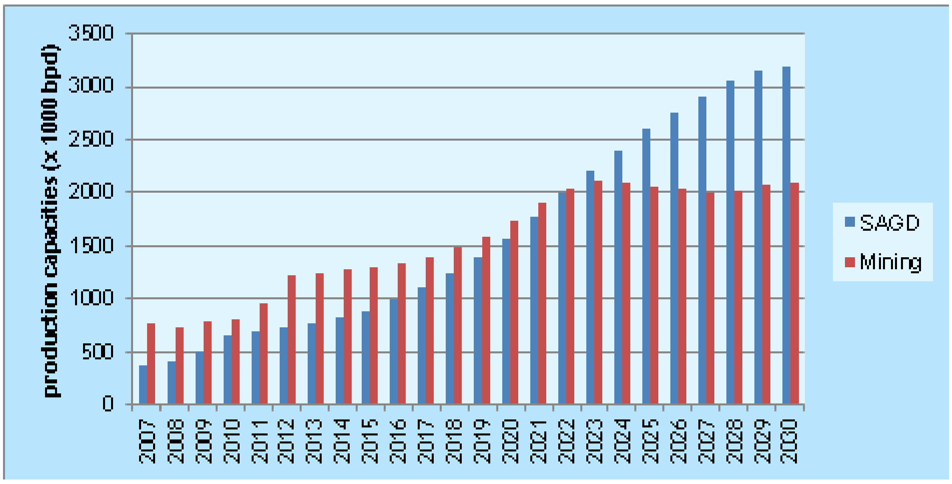
3.3.1 Production capacities, per type of mining (Canada)

The following input data on oil sand fields is used:

- production volumes and expected investment volumes 2012-2020 for tar sands crudes from Canadian oil sands;
- expected investment volumes 2020-2030 tar sands crudes from Canadian oil sands.

The data source for (future) production volumes is (CERI, 2012), see Figure 17.

Figure 17 **Expected growth in oil sand production capacity from steam-assisted and mining (Canada)**



Source: CERI.

The percentage with integrated upgrading to SCO is expected to change from 49% (2010) to 37% (2035) (Source: Canada - National Energy Board - Nov 2011 - Canada's Energy Future : Energy supply and demand projections to 2035 - Energy market assessment). From the above data source and figure, the production capacities used in the model are derived. The values used in the study are shown in Table 3.

Table 3 Expected production capacities and capacity additions (x 1,000 bpd), for Canadian oil sands

Capacities x 1,000 bpd	Existing/expected capacity (in year)			Expected capacity additions 2020-2030
	2012	2020	2030	
In-situ: SAGD, excl. integrated upgrading (Bitumen)	740	1,570	3,190	1,620
Mining with integrated upgrading (SCO)	586	769	827	58
Mining excluding integrated upgrading (Bitumen)	634	971	1,273	302

Note that all produced tar sands include either a form of upgrading (to SCO) or blending (to dilbit or synbit).

3.3.2 Production costs per type of mining (Canada)

a Projects operational by 2020

The total production capacity in operation by 2020, the typical marginal production costs for mining and in-situ production, with indication of range of production cost, is given in Table 4.

The data source is CERI, 2012. CERI developed a supply cost methodology to estimate production costs for a number of types of production which is useful for the modelling. From the total average operational costs indicated by CERI, we left out cost aspects relating to fixed capital expenditures (finance costs, relating to initial and sustaining capital requirements and the creation of a reserve for future abandonment costs). These costs relate to marginal production costs but rather to capital expenditure either at the beginning or at the end of a project’s life.

Cost values are expanded with intra field transport costs (1.5 CAN$/barrel) and, for the diluted bitumen mining types, blending costs (18.5 CAN$/barrel), based on a range of literature values. Note that the cost of diluent makes the types of production with external blending/upgrading positioned at a slight cost disadvantage compared to the mining with integrated upgrading.

Table 4 Data for projects operational by 2020

Type of production	Expected production capacity	Marginal production costs (US $/bbl)	
		Middle value	Standard deviation
	Million bpd	$/bbl	$/bbl
In-situ, SAGD, excl. upgrading (Bitumen, blended)	1.57	46.4	7.0
Mining with integrated upgrading (SCO)	0.77	43.9	6.6
Mining excl. upgrading (Bitumen, blended)	0.97	52.4	7.9

The share of uncertainty in production costs is modelled with a standard deviation of 15% of the middle value, and for this a normal distribution is used (see Paragraph 3.3.7). This means that, for example, for SAGD mining, over 95% of the data points are assumed to have average production costs of 46 ± 14 $/bbl (two times the standard deviation).

The standard deviation of 15% of the middle value is chosen to reflect the fundamental uncertainty in field location, transport distances, etc.

b Expected investments 2020-2030

For new investments, data was used on the total additions of production capacity, of all types of production, in the period 2020-2030. Furthermore, also typical investment costs, operational costs, and upgrading/handling/ transport costs are needed. The data used are indicated in Table 5.

Table 5 Data for new investments 2020-2030

Type of prod.	Expected prod. capacity additions	Typical investment costs		Operational costs ($/b)		Blending, handling & transport costs ($/b)		Duration of prod.
		Middle value	Standard deviation	Middle value	Standard deviation	Middle value	Standard deviation	
	Mil bpd	Mil $ per mil bpd		$/bbl	$/bbl	$/bbl	$/bbl	Years
In-situ, SAGD, excl. upgrading (Bitumen)	1.62	31,525	5,852	27.0	4.0	19.4	2.9	30
Mining with upgrading (SCO)	0.06	92,150	7,803	42.5	6.4	1.5	0.2	30
Mining excl. upgrading (Bitumen)	0.30	65,475	5,852	33.0	4.9	19.4	2.9	30

For the investment costs, the uncertainties have been established based on the given ranges of typical investment costs in Paragraph 2.2. We assume that 90% of the data sources are within this range.
Note that we have assumed duration of operation of 30 years for all types of products. Real life projects may have a longer duration of operation, however due to the discounting of revenue, the latter years of the lifespan are way less important than the first years[21].

For the operational costs and the upgrading/handling and transport costs, we have assumed an uncertainty to the magnitude of 15% of the middle value, for the same reason as detailed above.

[21] Calculating projects over a 40 year lifespan instead of 30 years typically improves a net-present value a few percentage points.

3.3.3 Oil prices (WCS)

The model calculations are carried out for different price levels of WCS and SCO. These price levels are key determinants of tar sands crude mining profitability. The full extent of the prices used in the model calculations is shown in Table 6.

Table 6 WCS (West Canada Select) prices for which model calculations have been carried out

Oil price case (WCS):	WCS price ($/barrel):
Case 1 - '05-12 WCS all time low: $ 30	30
Case 2 - WCS low case of $ 40	40
Case 3 - WCS mid/low case $ 50	50
Case 4 - actual (Jan 13) WCS : $ 60	60
Case 5 - 2020 EIA low (Brent - $ 70)*	70
Case 6 - 2030 EIA low (Brent - $ 80)*	80
Case 7 - '10-12 WCS high/Q1 WTI - $ 90	90
Case 8 - Q1 Brent - $ 110	110
Case 9 - 2020 EIA high (Brent - $ 160)*	160

Note: In the first column we present some references to the prices chosen, including the US EIA estimates for 2020 and 2030. Some of the reference relate to other crudes or indices than WCS. Note that we have taken these values and fed them into the model as if it were WCS prices. At these WCS price levels, actual Brent or WTI prices will likely be higher than the values indicated.

We show model results for all of the WCS price cases, without expressing a probability of one specific price case.
Generally, the lower price levels reflect the present situation (in which price levels of WCS and also SCO are substantial lower than those of WTI and Brent, due to constraints in transport and refining capacity).
The higher price levels (marked Brent and WTI) reflect potential future developments, in which products of unconventional crudes can be exported to global markets. These prices are realistic when the following conditions hold:

1. Global oil prices remain as-is.
2. Constraints for transport of oil from Canada to the PADD II region have been lifted.
3. Transport capacity within the USA between PADD II and the refineries at the Gulf Coast has been realised.

Note that the model assumes calculations for the western Canada locality. The price shown in Table 6 is therefore for the WCS (Western Canadian Select) benchmark. Brent and WTI prices are shown not because they are explicitly part of the model, rather as scenario cases. In all likelihood, WCS prices will always remain lower than WTI or Brent. If model calculations are carried out at a WCS crude price of e.g. 160 $/bbl (highest price from Table 6), the actual Brent and WTI prices will likely be somewhat higher.[22] For our model calculations, only the WCS benchmark price is relevant.

SCO has a price premium over WCS because this upgraded product is very well comparable to light crudes (such as Brent) and can be refined in a wide range of refineries.

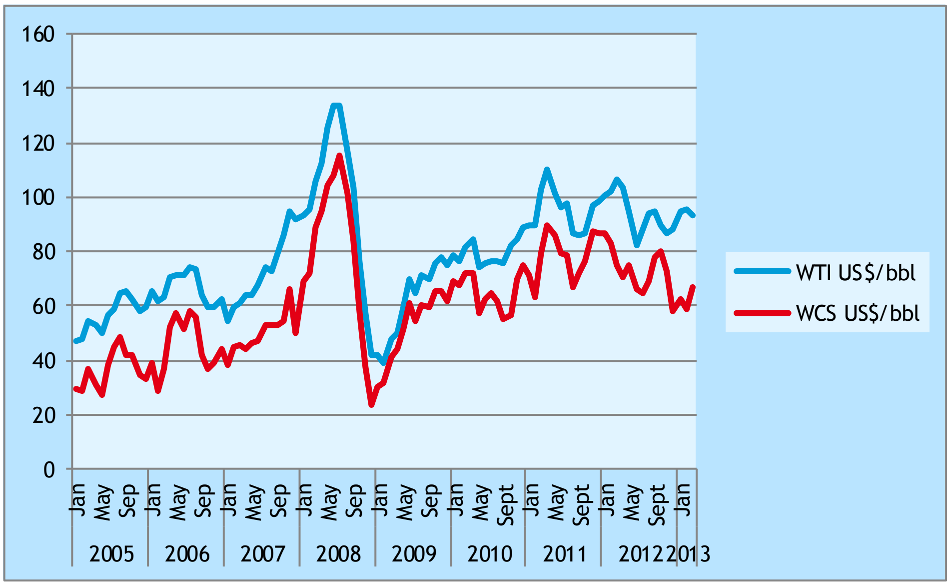
22 Because heavy crudes such as WCS typically have prices lower than lighter oils such as WTI or Brent, if the model calculations are carried out with WCS price setting of $ 160 per barrel, then the underlying oil price expressed in WTI or Brent will be higher, for example $ 175 per barrel (depending on actual spreads between the benchmarks).

The model calculations include both WCS and SCO prices. The model is given a WCS oil price case as input, and then the WCS:SCO spread is used to calculate the SCO price.

This spread typically is 20-25 $/bbl, as of 2012. In the model we have calculated with a fixed value of 20 $/bbl, composed of:
– a price premium of $ 2 of SCO over WTI (SCO is a better quality);
– the long term average spread between WCS and WTI of 18 $/bbl (see Figure 18).

The oil price level for the integrated mining and upgrading is the applicable WCS price (from Table 4 above) + the spread of 20 $/bbl.

Figure 18 **Long term prices WCS vs WTI (Baytex energy corp. benchmark heavy oil prices)**



For the purpose of experimentation, the model allows for selecting different SCO:WCS spreads, as indicated in Table 7.

Table 7 **Possible values for the WCS:SCO price spread selectable in the model**

WCS : SCO price spread	
Very high case - $ 40	$ 40
High case - $ 30	$ 30
Avg 2012 - $ 20	$ 20
Low case - $ 10	$ 10

3.3.4 FQD margin effect

The effect of the FQD emission reduction obligation on operating margins in 2020 and in the period 2020-2030 is the key parameter of which the influence needs to be assessed.

For the FQD induced price differential a range of values have been used, including those put forward in the Wood Mackenzie study (1.00 $/bbl), and a higher and a lower value of 3.0 and 0.5 $/bbl.

3.3.5 For new investments: cost of capital

The business case for new investments is evaluated by calculating the Net Present Value of the proposed projects. For this calculation, a discount rate to be used needs to be assumed. We have chosen to use a weighted average cost of capital as the discount rate.
In this study, calculations have been carried out with 10% for the weighted average cost of capital (WACC). The model allows for different percentages though, for the purpose of experimentation. The full range is given in Table 8.

Table 8 Discount factors used in model calculations

Discount factor/cost of capital	
WACC 6%	6%
WACC 8%	8%
WACC 10%	10%
WACC 12%	12%
WACC 15%	15%
WACC 20%	20%

3.3.6 CO_2 emissions

For the difference between the options with and without a price differential, the corresponding effects on GHG emissions are calculated.
The basis for this calculation is the difference between typical GHG emissions for tar sands crude and the average GHG emissions of petrol entering the EU markets. These are based on the proposed EC default values for conventional crude (87.5–89.1 g CO_2 eq per MJ fuel value) and the emissions from oil sands (107-108.5 g CO_2 eq per MJ).

This yields a 'delta' of CO_2 extra CO_2 emissions per barrel of tar sands oil produced of 102,1 g CO_2 per barrel (average of petrol and diesel).
The calculation is given in Table 9.

Table 9 EC Default values for GHG emissions of crudes and diesels derived from crudes

	WTW CO_2 eq emissions	TTW	WTW	WTT
	gCO_2/MJ	$kgCO_2/bbl$	$kgCO_2/bbl$	$kgCO_2/bbl$
Conventional oil - petrol	87.5	384.00	466.67	82.67
Conventional oil - diesel	89.1	384.00	460.49	76.49
Nat. bitumen - petrol	107	384.00	570.67	186.67
Nat. bitumen - diesel	108.5	384.00	560.75	176.75

It should be noted that the overall reduction required by the FQD on GHG emissions is determined in the FQD itself, with the obligation of a (nominal) 6% reduction in well-to-wheel emissions in fuels. However, if there is no differentiation among different crudes in the FQD, this will significantly limit upstream impacts.

3.3.7 Processing of data

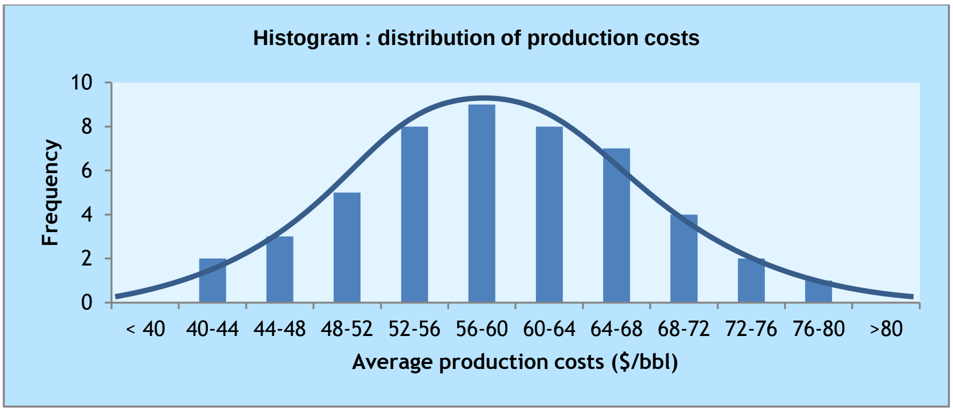
In the above, we have introduced uncertainty values in terms of standard deviation for marginal production costs (existing projects) and installation costs; operational costs; transport/handling/upgrading costs (new investments). These uncertainty values are used in generating a data set to be used in the analysis.

In many data sources, cost estimates are given as point values. In other data sources, typical cost values are given as a range, without indication of a likely middle value or other statistical parameters to characterise the shape of the distribution. However, for the purpose of quantitatively estimating the effect of a small change in operating margin on a very large number of possible mining sites and production wells, this does not suffice, we need a more elaborate dataset. Using only a few point values would negate that, for actual projects, e.g. marginal production costs vary between projects due to specific characteristics such as location, nature of the oil sands, extraction technology used.

Therefore we have worked with the normal distribution, and generated a distribution of data set to reflect an underlying population of actual production sites/wells. This assumption means that we assume that the production costs (and other costs that are varied) are not skewed in a particular direction but can be accurately captured by a central value and a standard deviation. The normal distribution is a reasonably safe choice as it is observed commonly in nature (such as when a large number of samples are drawn from a population, the samples follow a normal distribution, irrespective of the underlying distribution).

For the modelling approach to estimate impacts on existing production sites, the normal distribution, the approach is illustrated for one mining type in Figure 19. Per mining type, the total volume of production capacity has been divided in 50 slices. Each of these slices represent then 1/50th of the total production volume of the mining type. Per 2 percentiles slice, its marginal production costs are calculates so that the total distribution of production costs follows the normal distribution.

Figure 19 Production costs in a normal distribution



For the assessment of possible FQD effects on existing projects, the normal distribution is used for one parameter per mining type (marginal production costs).

For the assessment of possible FQD effects on new investments, the normal distribution has been used for three parameters per mining type: investment costs, marginal operational costs, blending, handling and transport costs.

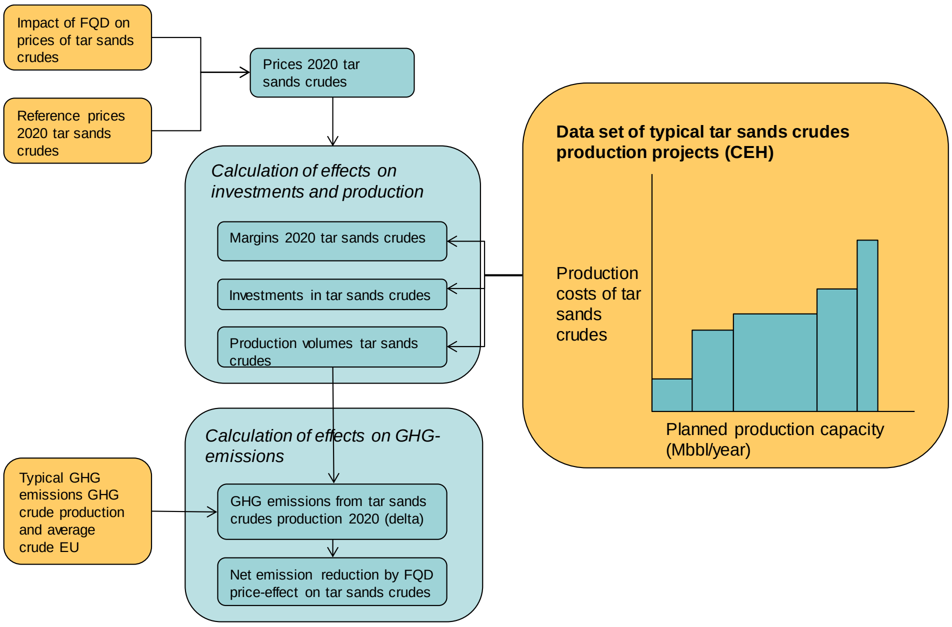
3.4 Model workings

3.4.1 Main structure

The model assesses the effects of the FQD, in terms of potential price impact on heavy crudes, and translates the price differentials into expected changes in production volumes or investment levels and estimates the consequences thereof for the overall CO_2 emissions for the entire supply chain. The outcome is compared with the 6% CO_2 reduction target.

The model's main structure is depicted schematically in Figure 20.
The base year for which assessments are carried out is 2020. A separate assessment is carried out for existing projects (oil sand fields in production in 2020) and new investments expected in the time window 2020-2030.

Figure 20 Schema of the model structure



3.4.2 Limitations of modelling approach:

The modelling approach uses crude oil price levels and installation, production costs of 2010-2012, which are extrapolated and to hold true for 2020.
This means that project economics does not change in real terms over the period 2013-2020[23]. Considering some fundamental uncertainties for the purpose of the modelling exercise, this a safe working assumption that suffices. Costs can increase in real terms due to a number of technological and workforce constraints, energy or commodity price developments.

[23] A refinement would be looking at the change in project economics over the last seven years (if data can be found), and extrapolate that. This could be done in a future version of the model.

Likewise so, costs can also decline due to economies of scale and technological progress. In the techno-economic study on mining by CERI (2012), crude prices are assumed to remain essentially constant in real terms[24].

CERI (2012) contains an analysis of exchange rate impact of the US dollar vs. the Canadian dollar based on macro economic currency market trends.
For this analysis, for the purpose of simplicity, a fixed exchange rate of 0.97 US$ ≈ 1.0 CAD$ is assumed.

3.4.3 Existing projects

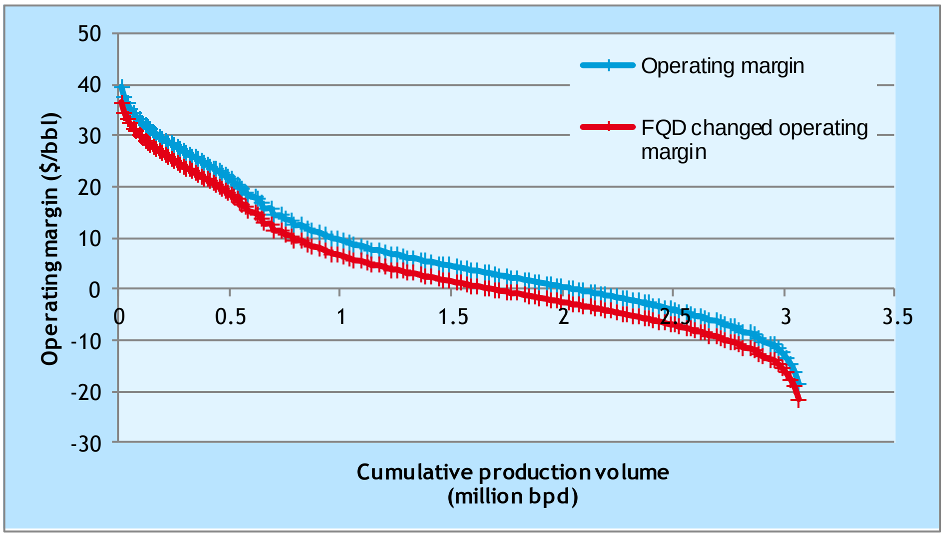
For existing projects, the modelling exercise is based on the marginal production cost. The model is composed of 50 'data points' per type of mining, so 150 data points in total. One 'data point' reflects a hypothetical mining project with a marginal production costs specific to this project, and a volume (1/50th of the applicable volume from Table 4. In the model for every data point (project), the market price for the product (WCS or SCO oil price) is compared with the marginal production costs.
The difference is the operating margin, which can be positive or negative. The operating margin becomes lower if the FQD price effect is assumed to be true. When the data points are sorted by operating margins, this yields Figure 21, showing the operational margins for all 150 data points both with and without a FQD price effect.
Then for both scenario's (baseline and FQD scenario), the projects are evaluated under the selected oil price case. Thus:

- If the market price for the product is higher than the marginal production cost, then it is assumed that the project is in operation and the mine/oil field remains in production. The quantity of production capacity with its associated CO_2 emissions is counted.
- If operating margins are negative, because the market price is lower than the marginal costs of production, then it is assumed that the production is stopped. The quantity of production capacity is not counted, and no CO_2 emissions take place.

The approach followed is a simplified way of evaluating an FQD effect and suffices for indicating whether a CO_2 effect would occur. The approach is valid on a long term perspective, and incorporates the notion that sunk capital expenditures are not part of an operator's decision to continue operation or not.
The analysis yields marginal cost curves of oil sand projects in Canada, with and without the FQD price effect, depicted in Figure 21.

24 A refinement is possible here. However we have modelled with a range of oil prices, which makes this simplification less important.

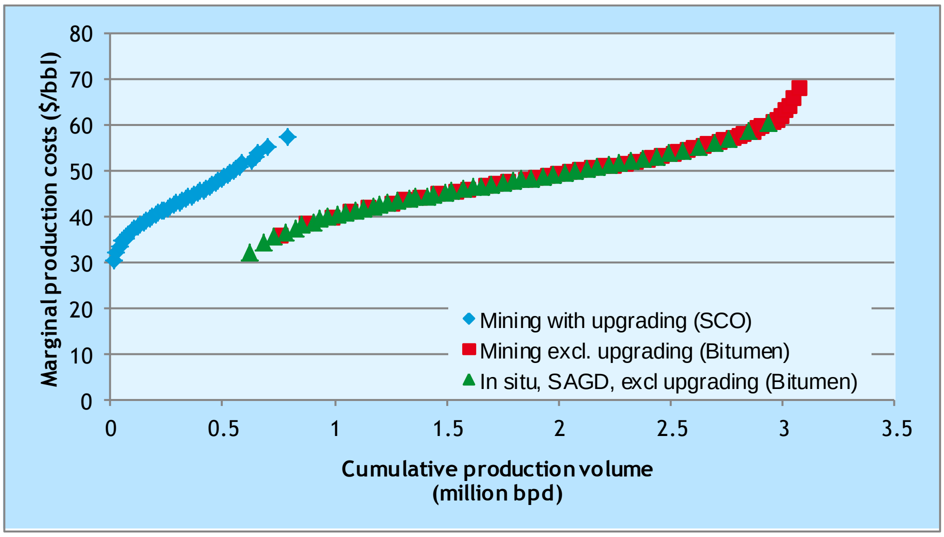
Figure 21 Operating margins for current projects (Canada) with indicated FQD effect
Figure displayed for a WCS price of 50 $/bbl and FQD price effect of 3 $/bbl



Due to the FQD price effect, the cost curve shifts downwards, which means that the point of intersection with the cumulative applicable production volume axis (X-axis) shifts leftwards. The model outcome is that under these conditions (WCS 50 $/bbl/FQD margin change of 3 $/bbl) an effect on production volumes is expected to exist. At (significant) higher WCS prices, the operating margin curve shifts upwards, and the likelihood of a FQD price effect is lower.
The change in point of intersection of the operating margin curve with the cumulative production axis depends on the level of the FQD price effect, and on the WCS price case that is expected. With WCS prices exceeding of 70 $/bbl, the operating margin curve lies above the X-axis, and the model predicts no effect on existing projects.

The marginal operational cost of the different types of mining are comparable to one another. Mining with integrated upgrading has the highest margins. Figure 22 shows the marginal production costs for the data points (x-axis sorting is identical to Figure 21).
The data points from mining and integrated upgrading have the best operating margins and are therefore displayed leftmost in the graph. Although the marginal operating costs per barrel are somewhat higher, the product (SCO) fetches a price premium over WCS blends.

Figure 22 Marginal operational costs for the different types of mining (sorted by declining net positive operating margins)



3.4.4 New projects

For new planned projects the key economic factor is the expected internal rate of return for an investor. If it is sufficiently high, then the project can go ahead and the resource will be exploited.
This business decision is modelled by calculating the Net Present Value over the economic life time of the project, with a discount factor equal to the weighted average cost of capital. If the NPV is positive, it is assumed that a project will go ahead and the oil field will be taken into production. If the NPV is negative, it is assumed that a project will not go ahead. The impact of the FQD on oil prices and therefore margins influences the NPV.

The NPV is calculated on the basis of the following formula:

$$NPV = -Inv + \sum_{t=1}^{30} \frac{Vol * P - C_{opex} - C_{upgr} - C_{transp}}{(1+wacc)^t}$$

The terms in the formula are:
- Inv: total investment costs for the applicable production capacity
- Vol: the realised production volume
- P: the applicable oil price for WCS
- C_{opex}: marginal operational costs
- C_{upgr}: upgrading costs
- C_{transp}: transport costs
- wacc: weighted average cost of capital
- t: the year of operation

The production volume is given by multiplying the production capacity with the capacity factor.

The following values are used:
- economic life: 30 years
- WACC: 10%
- capacity factor: 85% (integrated upgrading)/95% (others)

The economic life used is shorter than claimed for a number of projects. However for the NPV assessment, due to discounting, an error here will be very small (NPV results change about +4% for a lifespan of 40 instead of 30 years). Not included in the model are abandonment and reclamation costs, which could be added to the equation. Profitability of the investments would be lowered, although these costs are only at the end of the project's economic life, so similar to a higher economic life, the impact is very limited.
The WACC should include a measure of project risk. Arguably the value used (10%) is somewhat on the low side: the big oil companies usually aim for a return on investment that is higher to satisfy their equity shareholders, and the chosen discount rate assumes relative low project risk and high debt financing. On the other hand, the capacity factors are on the high side so the projects are evaluated with excellent revenues.

In the model, both investment costs, marginal operational costs and upgrading and transport costs are varied according to a normal distribution. The standard distribution is chosen so that 90% of the obtained values fall between the ranges observed in literature for these three cost parameters.
As three parameters are varied in this modelling part (investment costs, operational costs, blending, handling and transport costs), the data set thus generated from three starting parameters multiplied by three types of oil sand production, quickly grows. For the calculation we have 10 data points per parameter to vary, yielding a total data set of 3,000 data points. All of these data points represent a hypothetical investment project with its own typical techno-economic properties and profitability under a specific oil price.

The curve of the NPV values is then calculated for a given oil price and then shifted due to the margin change, for a specific given FQD margin change. Results for a example oil prices of 50 $/bbl and 80 $/bbl and assumed FQD margin effect of 3 $/bbl are indicated in Figure 23 and Figure 24.

- At a WCS price of 50 $/bbl (Figure 23), the majority of data points for proposed investments have negative NPV.
- At a WCS price of 80 $/bbl (Figure 24), the majority of data points have positive NPV, in which case the curve has a shape in one can recognize that in-situ SAGD projects (the left most 1.6 million bpd of expected capacity additions) have the highest NPV. This is due to their lower investment costs.

In neither of these examples the FQD price differential is a big driver, though the effect is more pronounced in the low price case. In the high case, profitability for almost all projects is sufficient for the impacts of an FQD price differential to be very limited.

Model results are computed for all 7 oil price cases and 3 values for FQD margin effects (63,000 calculations).

Figure 23 Curve of NPV values for the data points, under the baseline and under the FQD scenario, for WCS price of 50 $/bbl and FQD-margin effect 3 $/bbl

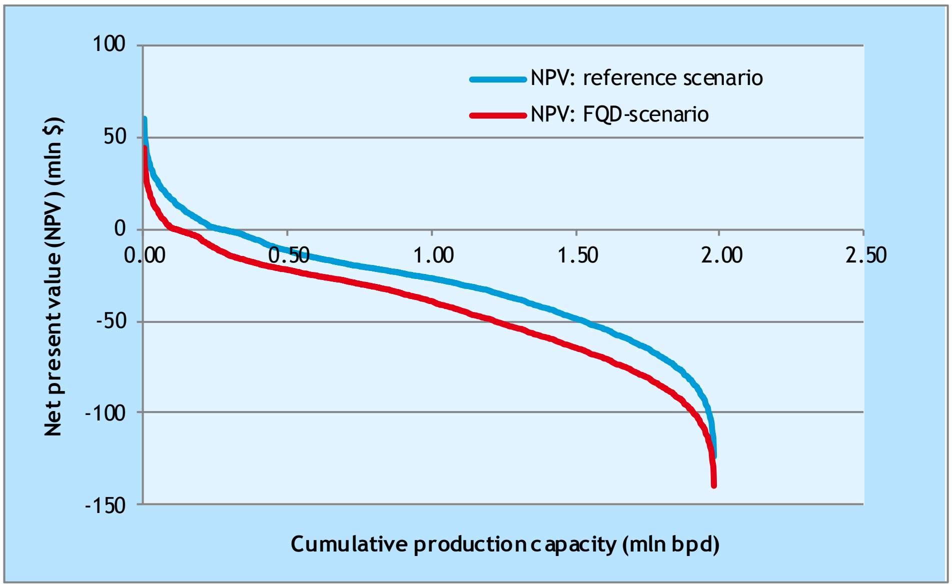
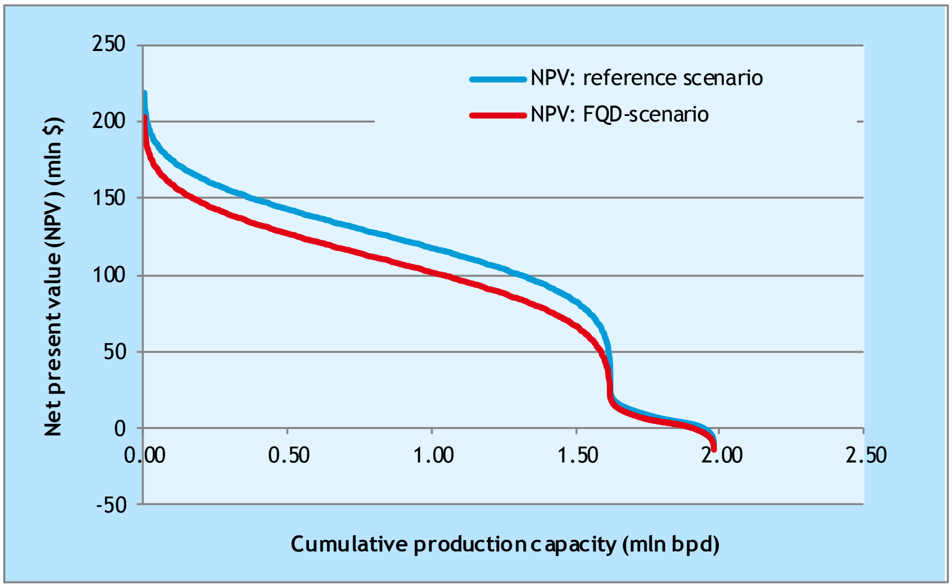


Figure 24 Curve of NPV values for the data points, under the baseline and under the FQD scenario, under a higher WCS price of 80 $/bbl and a FQD-margin effect 3 $/bbl



3.4.5 Calculation of the effect of the FQD price differential

The FQD effect is calculated by first calculating the profitable projects under the baseline, where crude prices are not affected by the FQD impact.
The applicable production volumes (intersection point of operating margin curve/NPV curve with the X-axis) are determined, and from that the corresponding CO_2 emissions.
Then the FQD price effect is added in. Given the then changed financial conditions, production volumes and emissions are assessed anew. Under certain combinations of oil prices, the point of intersection of the operating margin curve/NPV curve with the X-axis is shifted.

The difference between the two calculated cases is then the effect attributable to the FQD.

The effect of the FQD on production volumes and CO_2 emissions is assessed for three different FQD price effects on operating margins, see Paragraph 3.3.4.

3.5 Results

The results from the model calculations on affected production capacity and prevented CO_2 emissions are visualised in Figure 25 and Figure 26. The full model outputs, for existing projects and for new investments, are given in Figure 25 and Figure 26.

Figure 25 Calculation model results for effects on production capacity (existing projects and new investments)

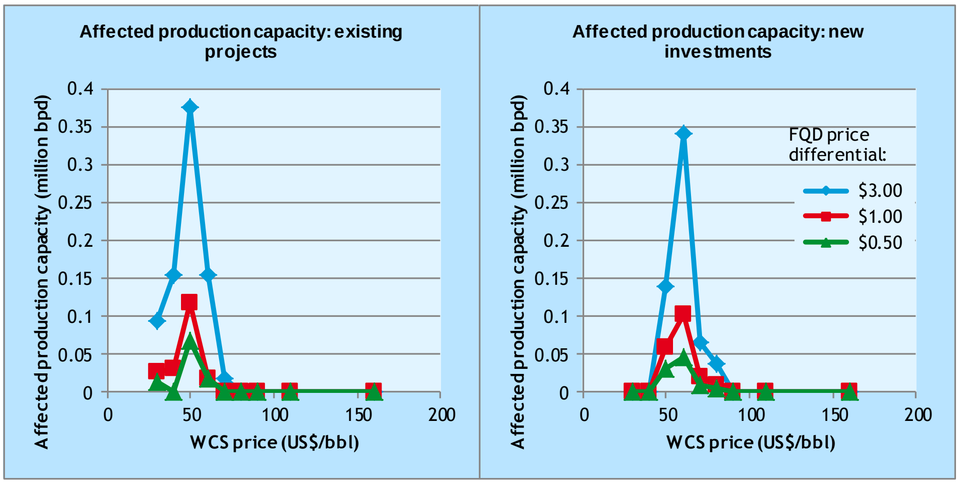


Figure 26 Calculation model results for CO_2 emissions prevented (existing projects and new investments)

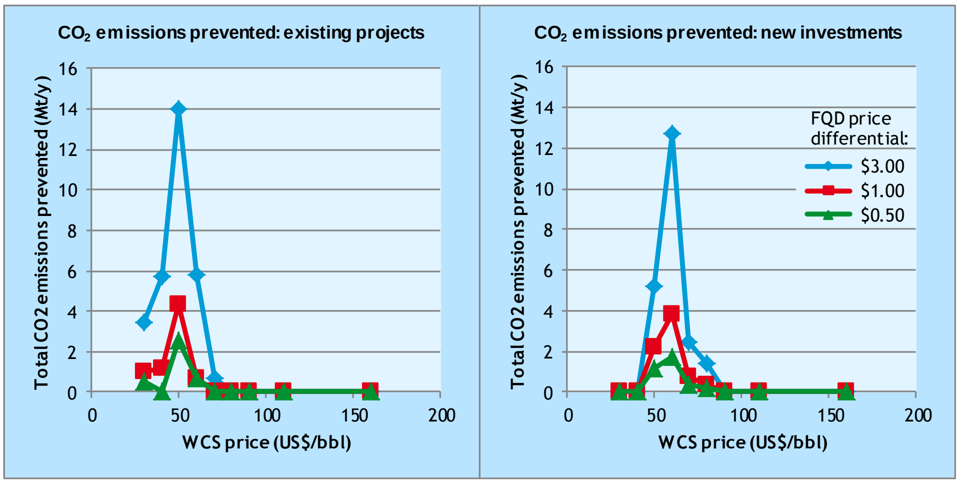


Table 10 Impact of a FQD price differential on production volumes and CO_2 emission of existing projects

Experiment	WCS crude price	FQD price effect	Total production volume, current projects (mln bpd)				Total CO_2 emissions, current projects (Mt CO_2 eq/y)			
	US $/bbl		Profitable, reference scenario	Profitable, FQD scenario	Affected	Affected %	Profitable, reference scenario	Profitable, FQD scenario	Affected	Affected %
1	30	3.0	0.5	0.5	0.1	-17%	20.4	16.9	3.5	-17%
2	40	3.0	0.9	0.8	0.2	-16%	34.9	29.1	5.7	-16%
3	50	3.0	2.0	1.7	0.4	-18%	76.3	62.3	14.0	-18%
4	60	3.0	2.9	2.7	0.2	-5%	107.6	101.8	5.8	-5%
5	70	3.0	3.1	3.0	0.0	-1%	114.4	113.7	0.7	-1%
6	80	3.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
7	90	3.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
8	110	3.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
9	160	3.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
10	30	1.0	0.5	0.5	0.0	-5%	20.4	19.4	1.0	-5%
11	40	1.0	0.9	0.9	0.0	-3%	34.9	33.7	1.1	-3%
12	50	1.0	2.0	1.9	0.1	-6%	76.3	71.9	4.4	-6%
13	60	1.0	2.9	2.9	0.0	-1%	107.6	106.9	0.7	-1%
14	70	1.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
15	80	1.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
16	90	1.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
17	110	1.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
18	160	1.0	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
19	30	0.5	0.5	0.5	0.0	-2%	20.4	19.9	0.5	-2%
20	40	0.5	0.9	0.9	0.0	0%	34.9	34.9	0.0	0%
21	50	0.5	2.0	2.0	0.1	-3%	76.3	73.7	2.5	-3%
22	60	0.5	2.9	2.9	0.0	-1%	107.6	106.9	0.7	-1%
23	70	0.5	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
24	80	0.5	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
25	90	0.5	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
26	110	0.5	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%
27	160	0.5	3.1	3.1	0.0	0%	114.4	114.4	0.0	0%

Results for new projects are given in Table 11.

Table 11 Impact of a FQD price differential on production volumes and CO_2 emissions of new investments

Experiment	WCS crude price	FQD price effect	Total production volume, new investments (mln bpd)				Total CO_2 emissions, new investments (Mt CO_2 eq/y)			
	US $/bbl		Profitable, reference scenario	Profitable, FQD scenario	Affected	Affected %	Profitable, reference scenario	Profitable, FQD scenario	Affected	Affected %
1	30	3.0	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
2	40	3.0	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
3	50	3.0	0.20	0.06	0.1	-69%	7.5	2.3	5.2	-69%
4	60	3.0	1.3	1.0	0.3	-26%	48.8	36.1	12.7	-26%
5	70	3.0	1.8	1.7	0.1	-4%	66.3	63.9	2.5	-4%
6	80	3.0	2.0	1.9	0.0	-2%	72.8	71.4	1.4	-2%
7	90	3.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
8	110	3.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
9	160	3.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
10	30	1.0	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
11	40	1.0	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
12	50	1.0	0.20	0.14	0.1	-29%	7.5	5.3	2.2	-29%
13	60	1.0	1.3	1.2	0.1	-8%	48.8	44.9	3.8	-8%
14	70	1.0	1.8	1.8	0.0	-1%	66.3	65.6	0.7	-1%
15	80	1.0	2.0	1.9	0.0	-1%	72.8	72.4	0.4	-1%
16	90	1.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
17	110	1.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
18	160	1.0	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
19	30	0.5	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
20	40	0.5	0.0	0.0	0.0	0%	0.0	0.0	0.0	0%
21	50	0.5	0.20	0.17	0.0	-15%	7.5	6.4	1.1	-15%
22	60	0.5	1.3	1.3	0.0	-3%	48.8	47.1	1.7	-3%
23	70	0.5	1.8	1.8	0.0	0%	66.3	66.0	0.3	0%
24	80	0.5	2.0	1.9	0.0	0%	72.8	72.6	0.2	0%
25	90	0.5	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
26	110	0.5	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%
27	160	0.5	2.0	2.0	0.0	0%	73.8	73.8	0.0	0%

From these results a number of interesting observations can be made.

1. When WCS prices are above 70 $/bbl, all existing oil fields are profitable and profitability will likely not be affected by the FQD.
2. When WCS prices are at or above 90 $/bbl, the business case for new investments is sufficiently positive to be likely be unaffected by the FQD at WCS prices of 70-90 $/bbl FQD impact is also very limited.
3. When oil prices are at or below 40 $/bbl, almost none of the new investments will be profitable, the total magnitude of FQD effect on new investments is limited: new investments are not taking place anyway so an FQD effect is not observed. On already existing projects, an FQD effect may make a number of the projects unprofitable.
4. Moderate to large FQD effects can be observed when oil process are between 40 and 70 $/bbl.

5. For existing projects, the most powerful effect can be observed with WCS oil prices around $ 50 per bbl. The total CO_2 savings can, in case of a 3 $/bbl price effect, amount to 14 Mt CO_2/y for Canadian oil sand projects[25].
6. For new projects, the most powerful effect can be observed with WCS oil prices around $ 60 per bbl. These effects can, in case of 3 $/bbl price differential amount to 12 Mt CO_2/y of savings due to investments not taking place or being postponed.

3.6 Sensitivity

In Paragraph 3.3.2 we have outlined the reason for working with standard deviations of 15% of the middle value. A concern is how results can change if the real data points of projects are spread beyond what is captured with this distribution. Perhaps the spread between different actual projects on marginal operation costs, or on blending, handling and transport costs is wider than captured with a 15% standard deviation.

To give insights into how model results would change, in this section we present results with a larger standard deviation twice what is used in the generation of the model results. With a standard deviation of 30% of the middle value, 95% of projects are assumed to lie within a range of ± 60% of the middle value, and 99% of the data points will fall within middle value ± 75%.

The expectation is that, with this wider spread on cost parameters, the boundaries on at what WCS crude prices, a supposed FQD price differential will have effect on production capacity and CO_2 emissions, will shift. One would perhaps expect that an effect could also be noticeable at for example higher WCS oil prices.

The results of the sensitivity analysis for a higher standard deviation are given in Table 12 for the existing projects, and in Table 13 for the expected new investments in the period 2020-2030.

We can observe that a higher standard distribution indeed shifts the results somewhat. One can observed that the impact on CO_2 emissions at WCS oil price of 70–80 $/bbl is somewhat higher for the new investments.
For the existing projects, the results around 40-60 $/bbl are impacted somewhat.
However, we cannot say that the conclusions of the modelling study can really shift through a higher standard deviation.

The model outcomes are the most sensitive to parameters that critically impact mine/well profitability, which include the WCS oil price and magnitude of the FQD price effect, of which we have explicitly shown the impacts.

25 These are savings, calculated based on the higher CO_2 emissions from tar sands crude oil production compared to conventional. See Paragraph 3.3.6.

Table 12 Sensitivity analysis results for existing projects, experiments with FQD price effect of 3 $/bbl shown

Experiment	Crude price (WCS)	Default value (s=15%) Total production volume, existing projects (mln bpd) Profitable, FQD scenario	FQD affected	FQD affected CO_2 emissions ($Mt\ CO_2/y$)	Sensitivity value (s=30%) Total production volume, existing projects (mln bpd) Profitable, FQD scenario	FQD affected	FQD affected CO_2 emissions ($Mt\ CO_2/y$) Total	Difference with default value (s=15%)
1	30	0.45	0.09	3.48	0.55	0.10	3.83	+ 0.3
2	40	0.78	0.15	5.74	1.06	0.20	7.43	+ 1.7
3	50	1.67	0.38	13.99	1.74	0.23	8.48	- 5.5
4	60	2.73	0.15	5.78	2.38	0.17	6.21	+ 0.4
5	70	3.05	0.02	0.70	2.83	0.07	2.54	+ 1.8
6	80	3.07	0.00	0.00	3.03	0.02	0.70	+ 0.7
7	90	3.07	0.00	0.00	3.07	0.00	0.00	+ 0.0
8	110	3.07	0.00	0.00	3.07	0.00	0.00	+ 0.0
9	160	3.07	0.00	0.00	3.07	0.00	0.00	+ 0.0

Table 13 Sensitivity analysis results for new investments, experiments with FQD price effect of 3 $/bbl shown

Experiment	Crude price (WCS)	Default value (s=15%) Total production volume, new investments (mln bpd) Profitable, FQD scenario	FQD affected	FQD affected CO_2 emissions ($Mt\ CO_2/y$)	Sensitivity value (s=30%) Total production volume, new investments (mln bpd) Profitable, FQD scenario	FQD affected	FQD affected CO_2 emissions ($Mt\ CO_2/y$) Total	Difference with default value (s=15%)
1	30	0.000	0.000	0.000	0.001	0.004	0.143	+ 0.1
2	40	0.001	0.002	0.091	0.047	0.049	1.843	+ 1.8
3	50	0.11	0.16	5.79	0.32	0.16	5.83	+ 0.0
4	60	0.95	0.32	11.79	0.93	0.20	7.52	- 4.3
5	70	1.69	0.09	3.26	1.54	0.13	4.78	+ 1.5
6	80	1.91	0.04	1.35	1.85	0.04	1.64	+ 0.3
7	90	1.98	0.00	0.08	1.95	0.01	0.46	+ 0.4
8	110	1.98	0.00	0.00	1.98	0.00	0.00	+ 0.0
9	160	1.98	0.00	0.00	1.98	0.00	0.00	+ 0.0

4 Conclusions

4.1 Current state of investment and prices of unconventional crudes

1. *Increasing production volumes from Canadian tar sands in recent years. Typical production costs in the range of 60–65 $/bbl*
   Canada, Venezuela and the US are currently developing tar sand crudes, of which they have vast reserves. Canadian tar sand production is anticipated to grow from 2 M bbl/day at present to 5 Mbbl/day in 2030. Venezuelan Orinoco developments depend largely on new investments waiting for a stable political investment climate, but recently new tar sand crude production has started at 0.4 Mbbl/day. In comparison: world oil production currently stands at around 95 Mbbl/day.
   Calculated on a life cycle (LCA) basis, crudes and products derived from these tar sands lead to an increase in CO_2 emissions, running counter to the aim of the FQD to reduce these emissions.
   Three major techniques for mining and processing of unconventional crudes can be distinguished: a) mining, extracting and upgrading; b) mining and extraction only, and c) steam-assisted gravity drainage (SAGD). Typical production costs for existing Canadian tar sand projects vary between 44 and 52 $/bbl, while for newly planned projects operational costs (including blending, handling and transport) typically range from 44 to 53 $/bbl. Investments for newly planned projects range from 32 to 92 M$ per unit production capacity (bbl/day). These figures do not include the costs of decommissioning/reclamation.

2. *Canadian crudes locked up in US Midwest due to logistic constraints*
   Canadian production developments are bottlenecked by export logistic capacity and by the condensate availability required for tar sand dilution prior to transport. The single export market for Canadian tar sands, at this stage, is the US Midwest. Not only are volumes constrained owing to transportation capacity shortage; the oversupply position in that region is also reinforced by a growing supply of US shale oil. As a consequence, the price spread of WCS relative to WTI has widened significantly and the crude market value has fallen by 10-40 $/bbl compared to similar crudes. In some cases current tar sand financial net-backs are merely recovering marginal production costs. Pipeline export to Asia via the West Coast has been delayed because of significant public and First Nation opposition. Export to the East Coast is under consideration via the conversion of a gas pipeline to crude (0.6 Mbbl/d).

3. *Refining capacity a crucial factor for export of Canadian oil sands. Asia/Pacific basin as primary outlet for Canadian crude exports*
   Exports of crudes from US tar sands are not likely in any significant quantity from Canada/Venezuela in the direction of Europe, since the required existing and future refinery conversion capacity is essentially located in the US, Caribbean and Asia, not in the EU. Canadian export volume and tar sand crude prices depend on new pipeline transportation capacity and additional export markets. Additional transportation capacity from Cushing to the US Gulf Coast (deep-conversion) refineries, is under construction and will accommodate more volume and an upward price netback effect relative to WTI/Brent.

4.2 The impact of the FQD regulation on the imports of unconventional crudes to Europe

4. *As European refineries have almost no capacity to process bitumen crudes, the impact of the FQD on the EU refining sector will be very small to zero.* The lack of export capacity combined with the lack of refining conversion capacity make it unlikely that tar sand crudes will find their way to Europe in any significant quantities in the coming years. Unlike previous changes to EU legislation (e.g. the directive on low-sulphur transportation fuel), the FQD is not likely to result in a need for additional investments in Europe. The claim of additional CO_2 emissions (1.4 Mt) stemming from export over longer distances to Asia instead of Europe, as stated by Wood Mackenzie/Europia, appears very unlikely, since no tar sand crude is expected to come to Europe. Also, with the lack of additional investment in
   EU refineries as a consequence of the crude differentiation in the FQD, it is highly unlikely that refinery cost numbers will rise beyond 1 €ct/litre as a consequence of FQD implementation.
   CE Delft/Carbon Matters conclude that the Wood Mackenzie statements, as published by Europia, are not supported with respect to the suggested impact on EU crude imports, additional trading distances and consequential CO_2 emissions, refining margins, risk of refinery closures and effects on fuel prices.

5. *There is a risk of increased imports of products and intermediates based on tar sand crudes, especially if projected pipeline capacity is built and if EU demand for diesel continues to grow*
   A different picture emerges on the product side. With new pipeline capacity coming on stream connecting Canadian crude sourcing areas with the US Gulf Coast, new export volumes of middle-distillate intermediates or blending components will become available for export to EU markets. Tar sand-based products such as gasoline and diesel or intermediates may well reach Europe specifically via the US Gulf Coast refineries.

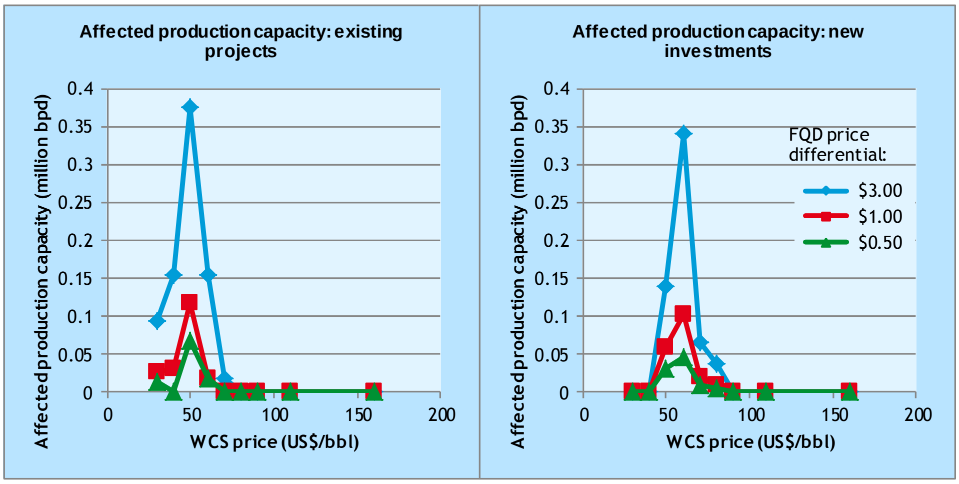
6. *Exports of products from Venezuelan tar sands to the EU to be expected*
   In view of the Venezuelan production locations and the availability of conversion capacity in the nearby US Gulf Coast area, lower transport costs to the EU vis-à-vis Asian markets can be expected. Therefore, significant product volumes may come available for export to EU markets.

4.3 Modelling environmental impacts of the FQD - key results

7. *A model has been developed that allows for a first-order evaluation of the potential impact of an FQD price differential for the production of crudes from tar sands in Canada*
   A starting point of the model is that the crude GHG differentiation in the FQD will have an effect on the prices of crudes produced from tar sands. For existing projects, the model determines the potential effect of the differential on the basis of marginal production costs. For newly planned projects the model determines effects on the basis of the net present value (NPV) of proposed investments. The model assumes that production costs, as well as investments and transport costs of existing and planned projects vary around median values, according to a normal statistic distribution.
   With the model the economic impact of an FQD price differential on tar sand projects has been determined for different price levels of WCS (West

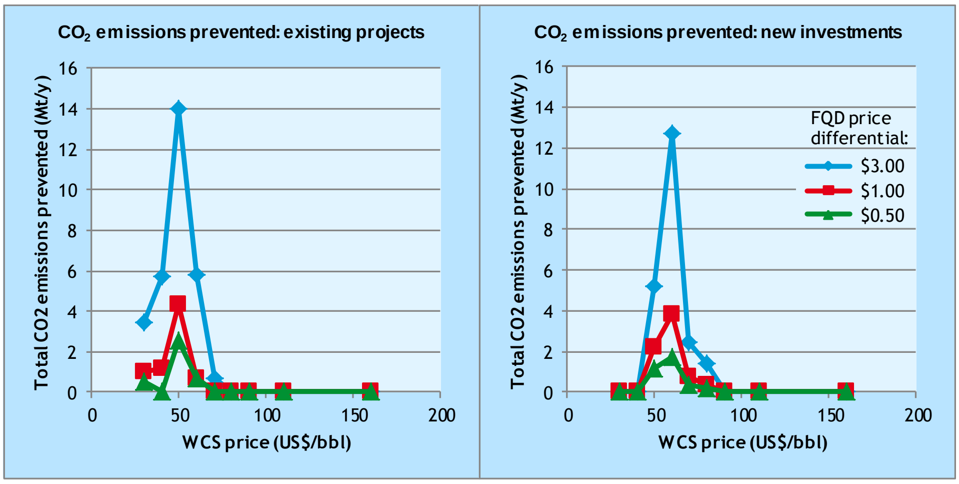
Canadian Select). The difference between projects being pursued with and without an FQD price differential can be considered as the net effect of the FQD on the production of unconventional crudes from tar sands. Figure 27 shows the modelled effects. This amounts to a maximum of 0.4 Mbbl/day at a WCS price of 60 $/bbl. Although substantial, the potential impact of the FQD remains relatively small compared with the current trading differentials of 10-40 $/bbl due to the lack of pipeline capacity.

Figure 27 **Modelled economic effect of FQD price differential on production of high-carbon crudes left: existing projects, right: new investments**



8. *Modelled impact of an FQD price differential on the GHG emissions of the crudes produced from Canadian tar sands is substantial*
From the model calculations it can be concluded that an FQD price differential will probably have an impact at price levels for WCS ranging from 40 to 90 $/bbl. Above 90 $/bbl no impact is expected.
This is illustrated in Figure 28.
For *existing projects* the most powerful effect can be observed at WCS oil prices around 50 $ per bbl, with CO_2 emission savings in the case of a 3 $/bbl price effect amounting to 14 Mt CO_2/y. For *new projects* the most powerful effect is observed at WCS prices around 60$/bbl where a 3 $/bbl price differential results in up to 13 Mt CO_2/y savings owing to investments not taking place or being postponed. Combined, for existing and new projects together, the maximum effect would be at a price level of 60 $/bbl, with savings of 19 Mt CO_2/y.
This effect is substantial and additional to the total emission reduction effect of the FQD of 60 Mt CO_2/y, deriving from meeting the domestic target to reduce GHG emissions by 6% by supplying alternative fuels.
In addition to the savings in CO_2 emissions, other environmental benefits might also be achieved (reduction in water pollution), as several projects will not materialise as a result of the FQD.

Figure 28 **Modelled impact of FQD price differential on GHG emissions on production of high-carbon crudes, left: existing projects, right: new investments**



9. *Effects of FQD on production of crudes from Venezuela depends on market developments*
   The model is based on the starting point of a price effect due to crude GHG differentiation in the FQD. The results show that in the case of such a price effect there may be an impact on production volumes and emissions. To what extent the FQD will result in price effects for tar sand crudes will depend on market developments. An important factor is to what extent products will be exported to the EU in relation to other markets.

Literature

Allen, 2013
Bitumen’s deep discount deception and Canada’s pipeline mania: an economic and financial analyis
Robyn Allen, 2013

API, 2011
Canadian oil sands
Washington : American Petroleum Institute (API), 2011

Birch, C. H. and R. Ulivieri, 2000
ULS gasoline and diesel refining study
Houston : Purvin & Gertz Inc., 2000

Blumberg et al., 2003
Blumberg, K.O., Walsh, M.P. and Pera, C.
Low-sulfur gasoline & diesel; the key to lower vehicle emissions
Washington : International Council on Clean Transportation, 2003

Brierley UOP, 2006
Changing refinery configuration for heavy and synthetic crude processing
Des Plaines, Illinois, USA : UOP LLC, 2006

Canada National Energy Board, 2011
Canada’s Energy Future – Supply and Demand projections to 2035
Calgary : Canada National Board, 2011

CAPP, 2012
Crude Oil: Forecast, Markets & Pipelines
Calgary : CAPP, 2012

CERI, 2012
Canadian Oil Sand Supply Cost and Development projects (2011-2045)
Calgary : CERI, 2012

CONCAWE, 2005
The impact of reducing sulphur to 10 ppm max in European automotive Fuels; an update
Brussels : CONCAWE, 2005

Directorate-General Environment, 2001
The costs and benefits of lowering the sulphur content of petrol & diesel to less than 10 ppm
Brussels : European Commission, 2001

EIA, 2012
Venezuela country update Oct
Paris : EIA, 2012

European Commission, 2012
The state of the European carbon market in 2012
Brussels : European Commission, 2012

European Commission, 2013
EU ETS factsheet, viewed 31-3-2013
Retrieved from:
http://ec.europa.eu/clima/publications/docs/factsheet_ets_2013_en.pdf

ICF, 2012
Impact Analysis of plans for implementing Article 7A of Directive 98/70/EC (FD), Part 1 and 2
Brussels : IFC, 2012

IEA ETSAP, 2010
Paris: Technology Brief P02 – May 2010 – Unconventional Oil & Gas production – www.etsap.org

Olivastri, B. and M. Williamson, 2000
Review of international initiatives to accelerate the reduction of sulphur in diesel fuel
Prepared under contract for: Oil, Gas & Energy Branch, Air Pollution Prevention Directorate, Environmental Protection Service, Environment Canada, 2000

Pembina Institute, 2013
Beneath the surface. A review of key facts in the oil sands debate
Drayton Valley, Canada : Pembina Institute, 2013

RBC, 2013
Nathan Janzen, Josh Nye
Macroeconomic impact of the WCS/WTI/Brent crude oil price differentials
Royal Bank of Canada (RBC), 2013

University Calgary, 2013
Hackett et al.
Pacific Basin heavy oil refining capacity
Calgary : University Calgary, 2013

Westfall, 2011
Midstream Summit Houston 2011 – The oil refinery buildout
Houston : Westfall, 2011

World Energy Council, 2010
Natural Bitumen and Extra-Heavy oil
London : World Energy Council, 2010

Wood MacKenzie, 2012
Wood MacKenzie down stream consulting, Impact of FQD Crude GHG Differentiation, final report to Europia, London, 2012

Wood MacKenzie, 2011
Netback Impact analysis of Canadian West Coast export capacity
London : Wood MacKenzie, 2011

Annex A Evaluation of claims in Wood MacKenzie study

In October 2012, Wood Mackenzie completed the study ‘Impact of FQD Crude GHG Differentiation’ on behalf of Europia. This study demonstrates the potential effects of the FQD introduction as proposed by the EU.
The summarizing slides are published through the Europia website (Wood MacKenzie, 2013).

This CE Delft/Carbon Matters report takes an independent view based on publicly available data and industry expert interviews. Within the context of this study also the study of Wood MacKenzie has been reviewed. No supporting evidence for the quantitative statements on price differentials, threat for refinery closures etc. could be obtained from the authors of this study. In that sense we consider the WM statements as statements for discussion but not be as facts.

Careful study of these slides provoke the following main comments and questions.

Wm study: “the EU Commission proposes to amend the FQD to discriminate against road fuels derived from certain specific arbitrary sources” CE/CM: The FQD is not amended in this field but identifies high-carbon crudes as potential sources of road transportation fuels and assigns a default CO_2 value to these products. Suppliers/producers are free to demonstrate that lower values should be applied to these products in case default values are too high. The FQD as such does not discriminate against specific arbitrary sources but assigns default values to products derived from unconventional crudes if no carbon content is provided . It should be noted that the onus is on the supplier to demonstrate CO_2 content. Whereas products specification can be derived from the product the CO_2 content is to be passed on in the supply chain. This matter was explained in the CE Delft FQD study of March 2012.
Wm-study: “it to be impossible to trace actual crude GHG, it can only get modelled” CE Delft/CM: In the March 2012 study of CE Delft and Carbon Matters, this Europia position was challenged stating that, whereas for intermediates it may well be more complex, GHG product LCA analysis are common practice in several industries and that in annual reports the GHG content of tar sand crudes are already specifically reported by for instance Exxon, BP and Royal Dutch Shell.
Wm-study “Increased GHG emissions stemming from crude differentiation and consequential crude shuffling: 1,4 Mton ton GHG emission increase by additional seaborne trade” CE Delft/CM Trade or additional trade does not increase GHG emissions. In case additional and longer transport is referred to it should be noted that presently no Canadian tar sands crude comes to Europe. No export facilities exist other that export options to the USA and potentially to Asia. We neither see additional transport nor substantiation of additional crude shuffling, potentially resulting in 1,4 Mtons of additional GHG emissions stemming from additional transport.

Wm study "The FQD will lead to changes in distribution based on price differentiation and refers to higher refining costs in Europe" CE Delft/CM: It is difficult to conceive that refining costs will go up with lighter crudes being processed in EU refineries. Nevertheless potentially a price differential could arise between high-carbon and low-carbon crudes with a supply price premium for low-carbon crudes. Determining for using the cheaper high-carbon crudes, however, is not so much the future FQD guidelines as well as the refinery capability for processing such heavy crudes. In the field of blending finished products, however, an impact of FQD guidelines can be anticipated in that cheaper tar sand-based intermediates may be less suited for European blending then elsewhere in the world because of FQD constraints.
Wm states EU refinery activity levels will be lowered as a direct result from the price differential leading to refinery closures CE Delft/CM: Given the fact that crude price is only one of the parameters and in view of the volatility of crude market prices, it is not to be expected that such differential will have a detrimental effect on European refining margins. On the other hand, additional differentials on market value of tar sand crudes of 2-3 may have an impact on profitability of tar sand crude extraction and production on the source side.

These statements may be substantiated in a full report that is not publicly available but the numeric claims made in 1) additional CO_2 emissions; 2) crude price differentials and 3) EU job losses as presented caused by the FQD are not provided.

Wm states that refinery margins for EU refineries may be heavily impacted, this up to impact levels of 7 $/bbl. Alternatively WM states that fuel cost numbers may go up significantly, this with numbers as high as 8 to 11 €ct/litre for mogas and diesel, respectively. CE Delft/CM: No supporting numbers for any of these numbers have been published. In addition, when compared with the incremental cost numbers, as historically achieved, when new product specifications had to be met on reduced sulphur levels, the incremental cost numbers, listed by Wm are at an astronomical level. Various analyses on cost impact of the sulphur guidelines on fuel prices have indicated that the impact on mogas/diesel was in the order of 0.5 €ct/litre for reducing sulphur from 350 to 50 ppm and as low as 0.07-0.3 €ct/litre for mogas and 0.2-0.6 €ct/litre for diesel when reducing sulphur levels from 50 ppm to 10 ppm. With the lack of additional investment in EU refineries , as a consequence of the FQD, and a limited incremental crude price differential it is highly unlikely that refinery cost numbers may go up beyond 1 €ct/litre as a consequence of FQD implementation.