FINAL REPORT

CO_2 Supply from the Fort McMurray Area 2005 - 2020

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EXECUTIVE SUMMARY

In 2006, CO_2 emissions from oil sands production were estimated to be about 43 million tonnes. In the same year, the Fort McMurray area produced about 760,000 bpd of synthetic crude oil (SCO) and another 165,000 bpd of in-situ bitumen. In the next ten years, SCO and in-situ bitumen production are expected to grow to over 1.8 million bpd and over 600,000 bpd, respectively according to the National Energy Board. SCO and bitumen production were highly energy intensive. With this tremendous growth in bitumen extraction activities, CO_2 emissions are expected to grow by the same order of magnitude. From an alternative perspective, the Fort McMurray area can be looked upon as a potential area to supply large quantities of CO_2 for geological storage or utilization purposes.

This Study has two objectives:

1. Generate a CO_2 supply forecast for the Fort McMurray area from 2005 to 2020; and
2. Generate a set of CO_2 cost curves for the Fort McMurray area and the technologies that might be applicable for CO_2 capture.

The potential CO_2 supply from oil sands operations is considered to be a direct function of bitumen and synthetic crude oil (SCO) production levels. Therefore, the initial step was to develop an oil production forecast for the region. For this Study, the forecast was developed based on publicly available data from several sources. The forecast was divided according to operation, including mining, steam assisted gravity drainage (SAGD), and upgrading production. Three forecast levels were specified:

- Low – includes all projects currently operating or under construction
- Medium – includes low plus approved and application projects
- High – includes all project status categories (operating, under construction, approved, application, disclosure and announced)

The low, medium and high labels refer to production level. Once the oil production forecast was completed, the CO_2 emissions of each of the processes/products were determined. These emissions are a function of the energy conversion processes involved in mining, SAGD, and upgrading processes. Accordingly, different processes/products require different energy commodities, which ultimately determine the overall CO_2 intensity and emissions in any given year. The methodology follows the earlier work of Dr. Ordorica-Garcia on the University of Waterloo's Oil Sands Optimization Model (OSOM), which is a stand-alone mathematical model to quantify energy demands and emissions of oil sands operations. OSOM assumes natural gas is the fuel of choice. However, in practice, fuel gas (a higher carbon intensive fuel) generated within the plant will be utilized first. Consequently the model tends to under-estimate the CO_2 emissions.

Of all the CO_2 emissions from oil sands operations, only a fraction can be feasibly recovered. In this Study, a unique "capturable" fraction is assigned to individual CO_2 streams from different processes (e.g., power, steam, hydrogen production). The capturable CO_2 is a function of the carbon removal technology used, the flue gas compositions, and inherent process limitations. For capture technologies, capture efficiency is assumed to be 90%. Thus, the overall CO_2 emissions and the "capturable" CO_2 emissions are reported. The latter constitute the actual potential CO_2 supply in the region. In the analyses, the supply is sub-divided into CO_2 from mining, SAGD, and upgrading operations. All non-stationary CO_2 sources (for example, mobile vehicles) are assumed to be non-capturable.

Finally, the CO_2 supply forecast is also provided as a function of the purity of the CO_2 streams generated from oil sands operations. The CO_2 concentrations of flue gases resulting from producing different energy commodities were determined by first-principles modelling and from the literature. The supply of CO_2 streams with various concentrations was thus determined. These concentrations range from less than 10% to roughly 50% (mole, dry basis). There are also high purity CO_2 streams (95+%) from three Benfield units in the Fort McMurray area.

Figures E-1, E-2, E-3 and Figures E-4, E-5, E-6 show the total CO_2 supply and total CO_2 supply according to CO_2 purity for the low, medium and high oil production cases.

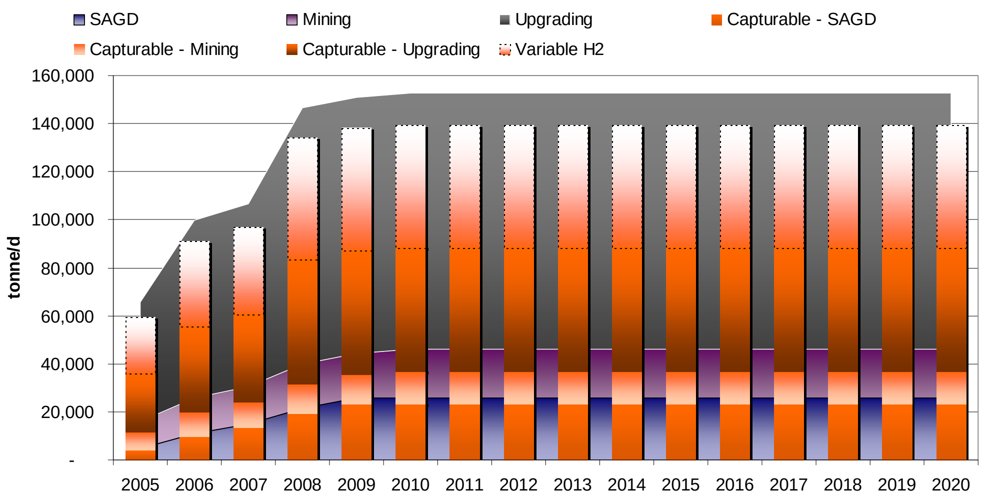

Figure E-1. Total CO_2 supply in Ft. McMurray 2005-2020 – Low

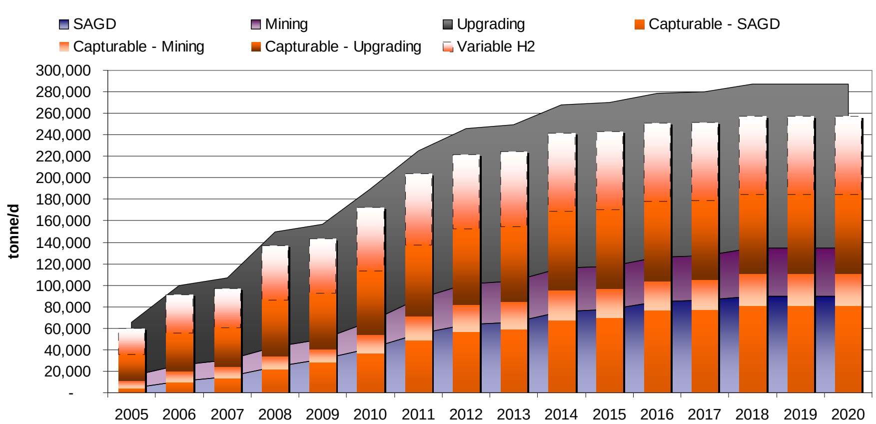

Figure E-2. Total CO_2 supply in Ft. McMurray 2005-2020 – Medium

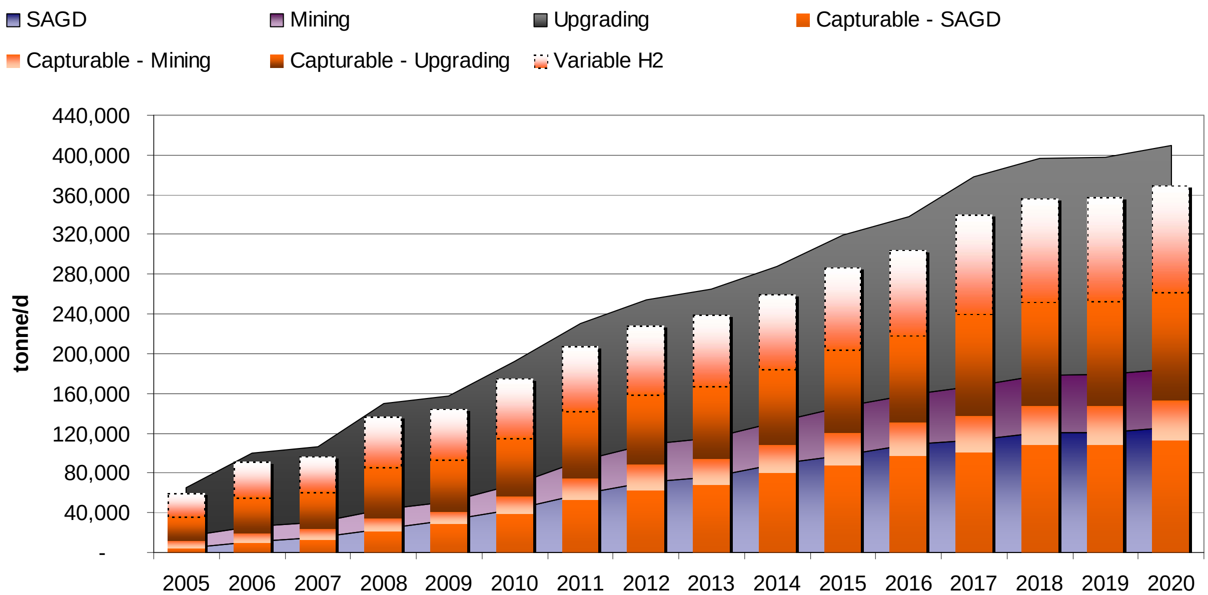

Figure E-3. Total CO_2 supply in Ft. McMurray 2005-2020 – High

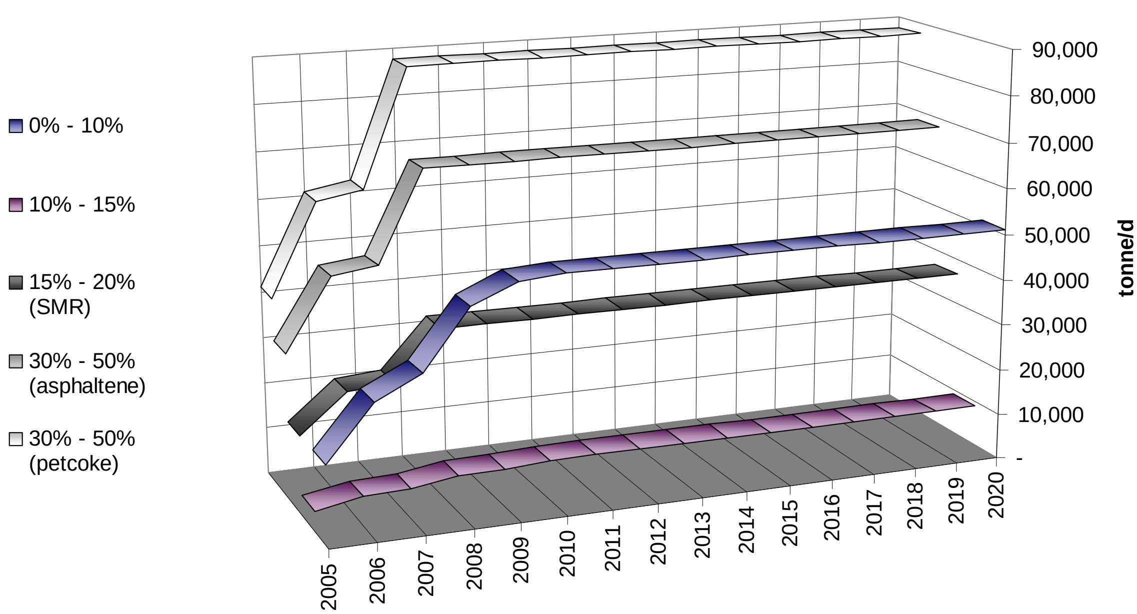

Figure E-4. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – Low

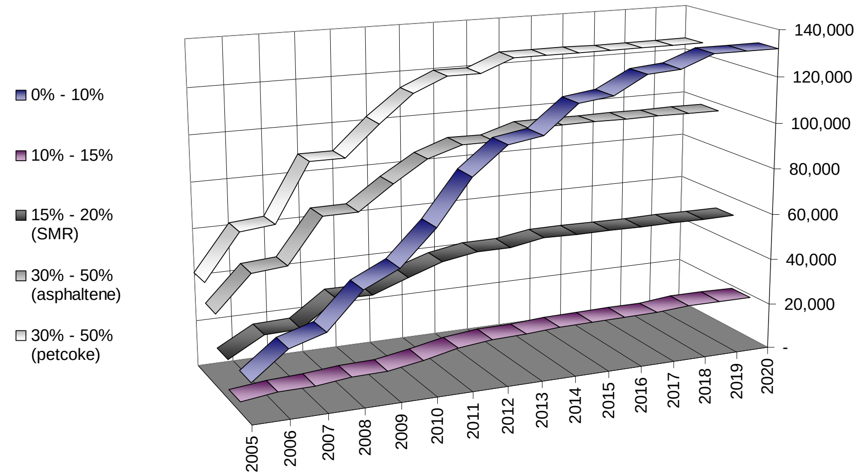

Figure E-5. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – Medium

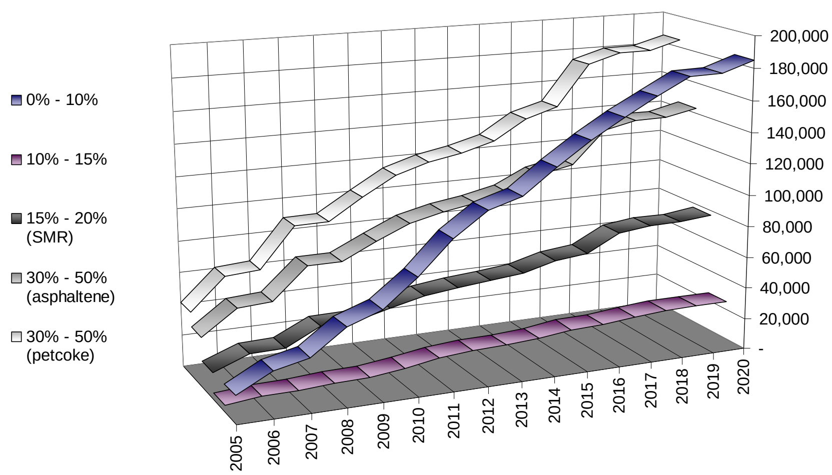

Figure E-6. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – High

In terms of the cumulative CO_2 supply between 2005 and 2020, upgrading operations have the largest contribution to CO_2 emissions growth, followed by SAGD and mining operations. The variability of CO_2 production in all scenarios is due to the feedstock choice for H_2 production. If asphaltene or petcoke are used instead of natural gas, the maximum CO_2 supply in the region escalates drastically. The maximum CO_2 supply is 88,000-139,000 tonnes/d in the low scenario, 184,000-257,000 tonnes/d in the medium case, and 261,000-369,000 tonnes/d in the high scenario. The overall CO_2 recovery potential ranges from 86% to 91% in all scenarios. The above figures correspond to peak production in 2020, where the high value corresponds to operations with gasification and vice versa.

The analysis reveals that the total CO_2 supply is largely determined by the production of steam and hydrogen, regardless of the scenario. Power generation has the third largest impact on CO_2 production, while the combined contribution of hot water, process fuel, and diesel use is roughly one-tenth of the total CO_2 supply. Across scenarios, steam generation contributes 24%-40% of total CO_2 production whereas H_2 production (if natural gas is used as fuel) accounts for 18%-

24%. If gasification of asphaltene is used instead, the share of H_2 production rises to 35%-45% while gasification of petcoke yields 45%-58% of total CO_2 production.

Concerning the purity of the CO_2 sources, our findings indicate that low-purity sources (0%-10% CO_2) are the most abundant across scenarios. The maximum CO_2 production from the above sources varies between 51,000 – 185,000 tonnes/d by 2020. CO_2 stream with purity in the 15%-20% range are the next more abundant, when gasification is excluded, at 36,000 – 77,000 tonnes/d. CO_2 sources in the 10%-15% range are the smallest at 9,000 – 25,000 tonnes per day by 2020. High-purity sources (30%-50%) are only available if gasification of bitumen residues is considered. The maximum potential production by 2020 ranges from 68,000 to as much as 185,000 tonnes/d by 2020, depending on whether asphaltene or petcoke is used.

The growth in low-purity (0%-10%) CO_2 sources is primarily driven by growth in thermal bitumen extraction, while increases in medium (15%-20%) and high-purity (30%-50%) sources are tied to growth in upgrading operations. Power generation is the main driver for the growth in CO_2 sources with a purity range of 10%-15%.

For waste gas streams low in CO_2 concentration and pressure, the capture options are limited. Chemical absorption is the preferred option. In this Study, we have reviewed the following processes:

(a) Conventional Amine Processes
- Mitsubishi Heavy Industries (MHI) KS-1
- Fluor Econamine FG+^{SM}
- ABB Lummus Crest
- HTC PureEnergy
- Cansolv

(b) Ammonia Based Processes
- PowerSpan
- Alstom

The front runners are Fluor Econamine FG+ and MHI's KS-1 process. Their experience and performance are similar. If a plant to capture CO_2 from combustion flue gases is to be constructed in the next 5 years, the process options are probably limited to one of these two processes. However, it should be noted that Fluor is the only company with experience on capturing CO_2 from the low CO_2, high O_2 concentration flue gas from gas turbine. The other processes mentioned above are either at small scale commercial demonstration or pilot stage. Therefore, in our opinion, these technologies would not be deployed at a commercial scale plant construction occurring roughly within ten years from now.

In terms of plant scale, most of the CO_2 plants constructed in the last few years are in the 300 to 500 tonnes per day CO_2 range. This is probably due to application requirement – urea production. In our opinion, a future single train will probably reach 3000 tonnes per day (1 million tonnes CO_2 per year) with a single absorber and can easily be extended to 6000 tonnes per day (2 million tonnes per year) with two absorbers and one regenerator.

We have carried out an economic evaluation of CO_2 capture on a number of waste gas streams.

The basis of the cost evaluation is a stand-alone CO_2 capture plant producing 2 million tonnes per year of CO_2 (5,500 tonne/d) with the CO_2 compressed to a pressure of 14.4 MPa (excluding pipeline cost). CO_2 recovery efficiency is assumed at 90%. The capture plant would generate all its steam requirements on site; hence there is no heat integration with other plants. Electricity is available to the site from the power grid.

For operating costs, natural gas and electricity are priced at $7.00/MMBTU and $80/MWh respectively; and cooling water is assumed available at reasonable price to the site. To calculate capital charges, a real rate of return of 10% and plant life of 30 years are used. A three year construction period is assumed, with the following capital expenditure profile, 25%, 35% and 40%.

The ARC Integrated Economic Model (IEM) is used to develop cost estimates for CO_2 capture using the MHI KS-1 solvent. A steam consumption of 1.3 t/t of CO_2 is assumed.

Table E-1 shows the cost of capturing CO_2 from a 3.5%, 9.2%, 13%, 18.6% and 44% CO_2 bearing waste gas stream.

Table E-1. Estimate of CO_2 cost for five CO_2 concentrations of 3.5%, 9.2% 13%, 18.6% and 44% CO_2 streams

2008 Canadian dollars $/tonne CO_2	3.5% CO_2*	9.2% CO_2	13% CO_2	18.6% CO_2	44% CO_2
Capital Costs $ MM	1234	629	479.8	396.8	263.3
Capital Charges	71.2	36.3	28.8	22.9	15.2
Fixed Costs	43.8	20.5	16.4	13.1	8.6
Variable Costs					
- electricity	23.2	10.5	8.5	6.6	4.5
- natural gas	26.5	28.4	30.2	28.8	30.5
- others	6.9	5.9	6.0	4.6	4.4
Total	171.6	101.6	89.8	76.0	63.2

* the waste gas stream does not contain sulphur, therefore desulphurization is not required

Figure E-7 shows the cost of capturing CO_2 for a range of CO_2 concentrations using a chemical absorption process. The cost of capturing CO_2 decreases as the CO_2 concentration in the flue gas increases.

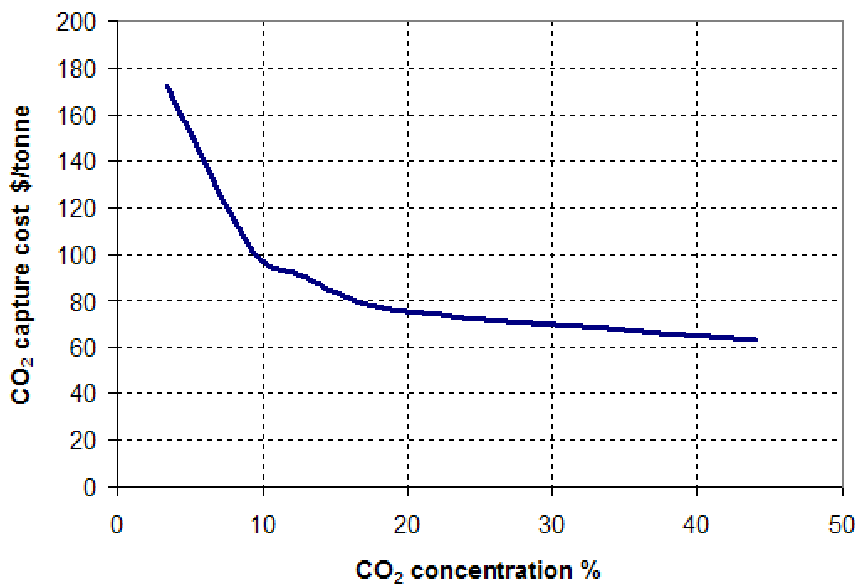

Figure E-7. CO_2 capture cost versus CO_2 concentration in the flue gas.

It should be noted that until recently, we were in an escalating cost environment. The Chemical Engineering Plant Cost Index has increased 48.6 % from 2003 to 2008 (ChE Plant Cost Index grew from 401.8 to 597.1), a rate increase of 8.2% per year for this period. This is in part due to escalating commodity prices like energy and iron and steel. In addition, Alberta was particularly hard hit by a shortage of skilled labor. Therefore, the cost estimate is prepared in a cost environment that is escalating and a tight labor market and should be treated accordingly.

There are three Benfield units operating in the Fort McMurray area – two from Syncrude and one from Suncor. They are used for hydrogen/CO_2 separation in the older hydrogen plants. CO_2 supplies from these units are 1730 ky/year and 280 kt/year, respectively. These streams are essentially pure, 99+% CO_2. To produce CO_2 from these streams does not require any capture operation, just gathering, dehydration and compression. Using the same economic evaluation basis, the cost of the CO_2 produced would be about $18.8/tonne.

Based on the analysis in this Study, CO_2 supply cost curves from the Fort McMurray area in 2020 for the low, medium and high oil production cases are constructed (see Figure E-8).

Figure E-9 shows the CO_2 Supply Cost Curves from the Fort McMurray Area in 2020 for Medium Oil Production Case, for SMR, SMR + Gasification and Gasification with Petcoke. With the introduction of gasification, the total CO_2 supplies increase, more so with gasification of bitumen pitch than petcoke. It also reveals the emergence of significant quantities of the ~ 50% CO_2 concentration streams.

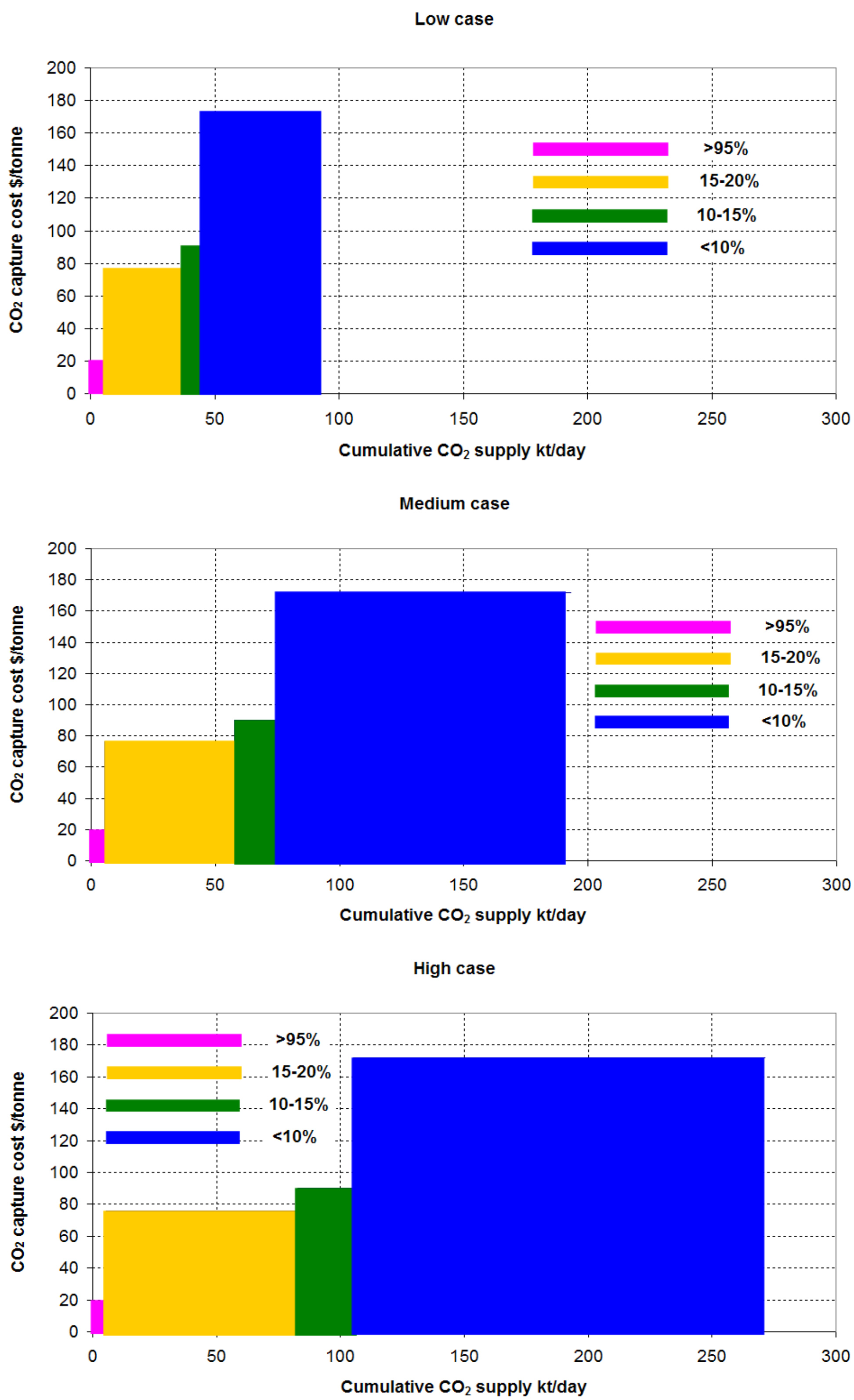

Figure E-8. CO_2 supply cost curves from the Fort McMurray area in 2020.

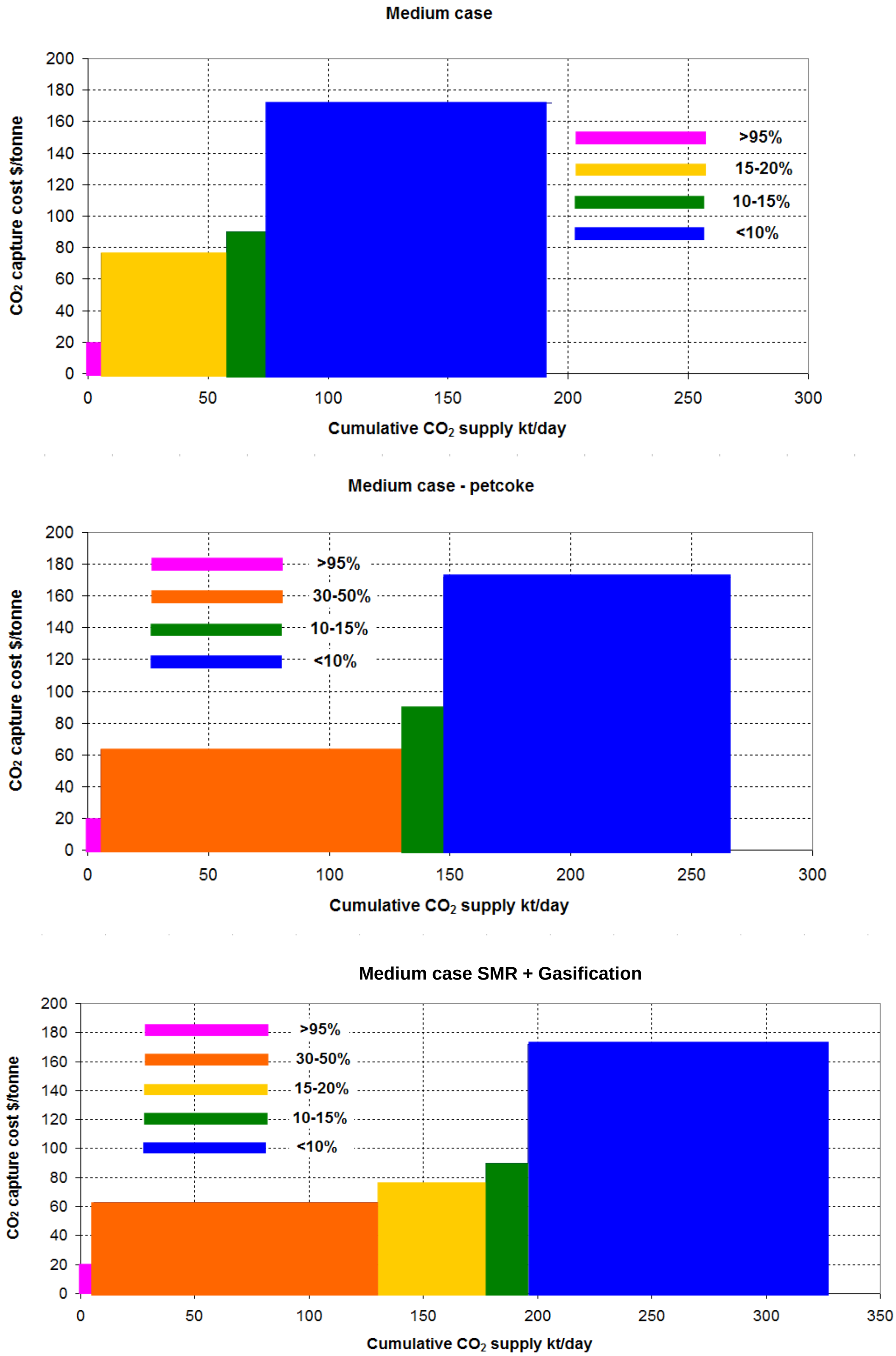

Figure E-9. CO_2 supply cost curves from the Fort McMurray Area in 2020 for medium oil production case, for SMR, Gasification with Petcoke and SMR + Gasification.

As part of this work, we have studied the operations of Opti-Nexen at Long Lake, Alberta, as it is the only project currently producing hydrogen and steam from the gasification of asphaltene in the Fort McMurray area. A base model of the main processes involved in the aforementioned operations, namely: upgrading, gasification, and co-generation was constructed. This first principles model is based on our current understanding of the above processes. Using this base model, energy and material balances for the Opti-Nexen Long Lake operation were generated and the CO_2 emissions estimated.

Mitigating emissions from an integrated upgrading-gasification process such as Opti-Nexen's Long Lake project via carbon capture and storage (CCS) involves modifications to the process. This is commonly referred to as a CO_2 retrofit. Retrofitting plants that were not designed with provisions for future implementation of CCS generally involve the following:

- Addition of a CO shift section
- Addition of a CO_2 removal unit
- Addition of CO_2 drying and compression facilities
- Modification of gas turbine to operate on hydrogen instead of syngas fuel
- Addition of air compression capacity for the air separation unit, ASU (if necessary)
- Capacity increases of plant utilities

To effect the above additions and modifications, physical space, capital, and additional energy production are required. Thus, the techno-economics of a retrofitted process will differ from those of the original and are a function of the extent of CO_2 captured and the specific technologies chosen by the designers.

Table E-2 summarizes the options for CO_2 retrofit analyzed in this Study and compares them to the process pre-CO_2 retrofit. All of the options feature a CO_2 capture efficiency of 90%. In the Selexol plant cases, the assumed CO shift is 90%. In all cases, the steam, hydrogen, and power demands of the Long Lake plant are met.

In terms of steam demands, the post-combustion capture option requires the most steam of all cases. This has two direct implications: 1) dedicated steam boilers must be added to the process, and 2) natural gas supplementation is a must, as the syngas is insufficient to satisfy the power and steam needs of the process. The Selexol-based cases have a modest steam requirements increase due to the CO shift, which could potentially be supplied by the existing Heat Recovery Steam Generator (HRSG).

Table E-2. Comparison of CO_2 retrofit cases

Feature	Original process	Sweet CO shift	CO shift + full H_2 extraction	Post-combustion CO_2 capture
Solvent for CO_2 capture	N/A	Selexol	Selexol	MEA
H_2 production (tonne/d)	531	531	1,331	531
Steam demands (tonne/d)				
SAGD	22,000	22,000	22,000	22,000
CO shift*	0	7,500	7,500	0
CO_2 plant	0	0	0	27,758
Total	22,000	29,500	29,500	49,758
Power balance (MW)				
CO_2 capture & compression	0	188	188	125
Net available	370	95	150	245
Natural gas supplementation (TJ/d)				
Upgrading	0	46	46	0
Co-gen plant	0	0	122	108
Total	0	46	168	108
CO_2 emissions (tonne/d)				
Co-gen plant	17,813	3,901	9,468	2,300
Upgrading plant	3,761	2,226	2,226	3,761
Total	21,574	6,127	11,694	6,061
CO_2 captured (tonne/d)				
Gasification plant	0	18,681	18,681	0
Co-gen plant	0	0	0	20,698
Purity (mole %)	N/A	92%+	92%+	99+

*Assumed steam:CO ratio = 1

The Selexol-based plants feature the highest power requirements for CO_2 capture and compression. The former is responsible for the largest share of these requirements, due to the need to recycle large volumes of recovered CO_2 in the initial stages of the solvent regeneration. This is done to minimize H_2 losses in the CO_2 stream, and requires additional compression work. In the absence of natural gas supplementation, this results in the largest reduction in power output of the co-gen plant, as the turbine operates at partial capacity. When natural gas is used to fully load the turbine, the net output increases by 50%, with respect to the syngas-only case.

Of the cases that use natural gas for fuel supplementation, the full H_2 extraction design features the largest gas requirements, followed by the post-combustion capture option. This is due to the fact that in the former, purchased gas is required for upgrading operations and for fuel supplementation in the co-gen plant, whereas in the latter natural gas is used exclusively for steam production for CO_2 capture. The CO shift case has the lowest natural gas demands of all.

The net CO_2 reductions achieved by all the options range from 45% to 72% with respect to the original process, prior CO_2 retrofit. The full H_2 extraction case has the highest CO_2 emissions of all cases, due to its extensive use of natural gas as supplemental fuel. On the other hand, the net CO_2 emissions of the post-combustion capture case and the sweet CO shift case are essentially the same.

The emissions reduction of the MEA case is achieved by capturing more CO_2 than its Selexol counterparts. The net CO_2 captured of the former is 11% more than the latter, yet the net emissions reduction of the two is practically identical. In practical terms, this means that CO_2 transport and storage costs of the MEA-based solution would be higher than those of the Selexol solution. This in turn, may translate into higher CO_2 mitigation costs on a per tonne CO_2 captured basis.

It is clear from the results on Table E-2 that no option has a definite advantage over the others. Multiple tradeoffs between natural gas requirements, value of co-produced energy products, and emissions reductions exist when retrofitting an Opti-Nexen type plant for CO_2 capture. An economic analysis of the above options is imperative to add clarity to the decision-making process. However, this will require a large degree of co-operation on the part of the operator.

In summary, based on a set of first principle models we have prepared a set of preliminary CO_2 supply cost curves for the Fort McMurray area from 2005 – 2020 and studied the impact of gasification on the cost curves. We have also investigated retrofit options for CO_2 capture for the Opti-Nexen operation in Long Lake and highlighted the complexity of the engineering issues. One aspect we have not investigated is the retrofit options for the steam generation in the SAGD operations. Application of oxy-fuel combustion for CO_2 emissions mitigation is a worthwhile R&D project.

CHAPTER 1

CO_2 COST CURVES STUDY OBJECTIVES

1.1 WHAT ARE COST CURVES?

Cost curves are a set of curves with the cost of capture in $/tonne CO_2 captured as the y-axis and the cumulative CO_2 supply capacity in million tonnes of CO_2 per year (or thousand tonnes of CO_2 per day) as the x-axis. As CO_2 is generated as a by-product of industrial activities, the supply of CO_2 will increase over time as more industrial activities are being implemented. The industrial activities could use different processes as well, and this could impact on the quality and quantity of the CO_2 waste gas streams. Capture technologies could also improve over time and this could potentially reduce the cost of capturing the CO_2. Therefore, cost curves are a set of dynamic curves responding to the changes in industrial activities and in the technology mix.

The present Study is a first attempt to develop CO_2 cost curves for the Fort McMurray area.

1.2 WHY FORT MCMURRAY?

Table 1.1 lists the Alberta Energy and Utilities Board (AEUB)'s estimate of Alberta's crude bitumen reserves.

Table 1.1 In place volumes and established reserves of crude bitumen in Alberta (billion barrels).

Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mining	101	35.2	3.9	31.2	18.3
In situ	1611	143.5	2.0	141.5	3.7
Total	1712	178.7	5.9	172.7	22.0

Source: AEUB Report ST-98-June 2008

Alberta's crude bitumen reserves are distributed in three main regions – the Athabasca region, the Peace River region and the Cold Lake region. In this Study, the Fort McMurray area includes the whole Athabasca region, as shown in Figure 1.1.

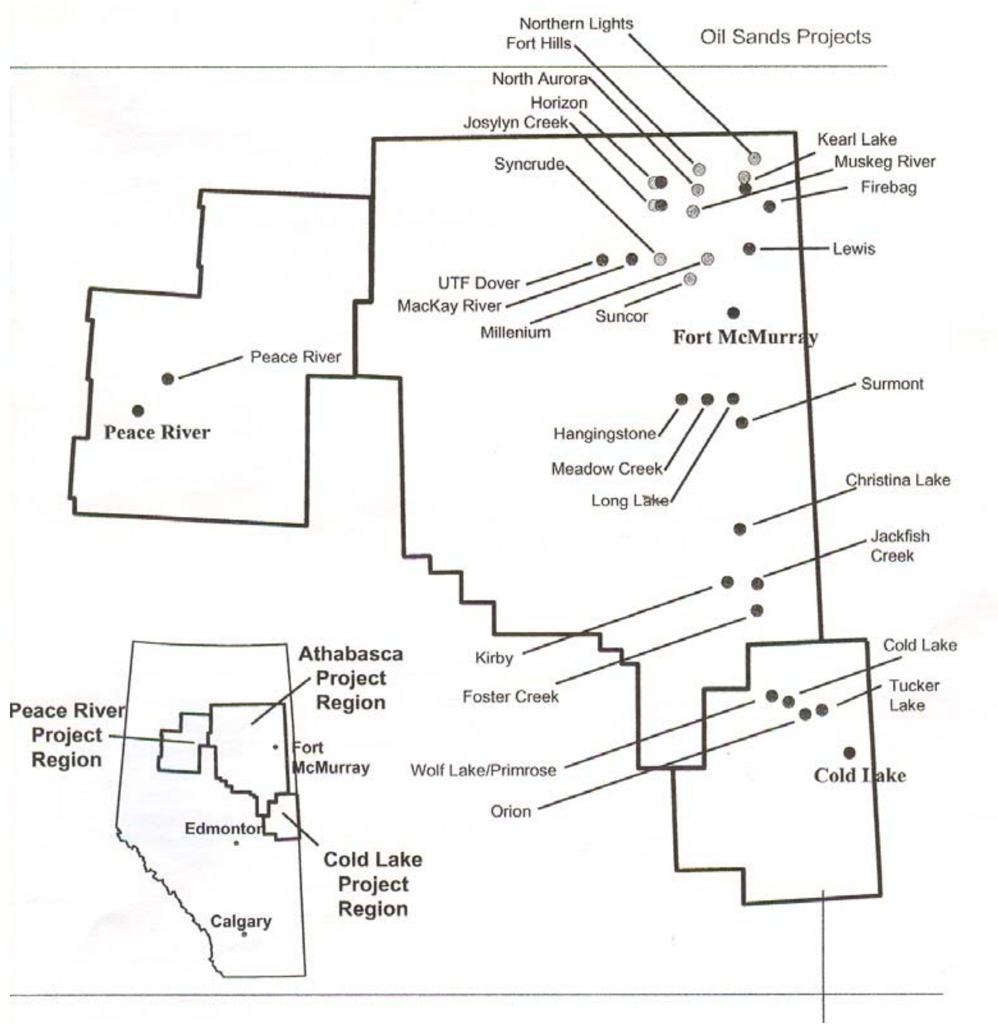

Figure 1.1 The Fort McMurray area

In 2006, CO_2 emissions from oil sands production were estimated to be about 43 million tonnes. In the same year, the Fort McMurray area produced about 760,000 bpd of synthetic crude oil (SCO) and another 165,000 bpd of in-situ bitumen. In the next ten years, SCO and in-situ bitumen production are expected to grow to over 1.8 million bpd and over 600,000 bpd, respectively according to the National Energy Board. SCO and bitumen production are highly energy intensive. With this tremendous growth in bitumen extraction activities, CO_2 emissions are expected to grow in the same order of magnitude. From an alternative perspective, the Fort McMurray area can be looked upon as a potential area to supply large quantities of CO_2 for storage or utilization purposes.

1.3 STUDY OBJECTIVES

The objectives of this Study are:

1. Generate a CO_2 supply forecast for the Fort McMurray area from 2005 to 2020; and
2. Generate a set of CO_2 cost curves for the Fort McMurray area and the technologies that might be applicable for CO_2 capture.

1.4 ORGANIZATION OF THIS REPORT

This Final Report is organized in Chapters.

Chapter 2 is a development of CO_2 supply forecasts for the Fort McMurray area from 2005 to 2020. The original intent was to use the Large Final Emitters inventory data as the basis to forecast CO_2 emissions. However, after evaluating the data, we found that the inventory does not provide detailed CO_2 data from different parts of the plant and fuel consumption data to allow us to construct a model. Therefore, we decided to use first principle to construct the forecast model, which is based on activities and fuel used. The fuel is assumed to be natural gas. In reality, fuel gas, which is generated within the plant, will be used first before purchased natural gas. As fuel gas generally has higher carbon content than natural gas, we might be over estimating the availability of low CO_2 concentration streams from the model.

Chapter 3 reviews the chemical absorption technologies suitable for capturing CO_2 from low CO_2 concentration waste gas streams. It also reports on the economics of the CO_2 capture using the MHI KS-1 solvent, for waste gas streams with CO_2 concentrations ranging from 3.5% to 20%. The ARC Integrated Economic Model (IEM) was used for the economic evaluation.

Chapter 4 evaluates the options for CO_2 capture from a gasification process. The Opti-Nexen operation at Long Lake was used for the analysis. Again the analysis was based on a first principle model using data in the literature and in their submissions to the AEUB. A number of retrofit options were analyzed. To go further than what we have done will require more engineering, input and data from the operator.

Chapter 5 provides the economics of producing CO_2 from the high purity CO_2 streams. It also includes some examples of the cost curves generated from this Study. Lastly we will make some suggestions for further research on the cost curves.

CHAPTER 2

CO_2 SUPPLY FORECAST FOR FT. MCMURRAY 2005-2020

2.1 METHODOLOGY

In this Study, the potential CO_2 supply from oil sands operations in the Fort McMurray area is considered to be a direct function of bitumen and synthetic crude oil (SCO) production levels. Therefore, the initial step is to develop an oil production forecast for the region. At the onset of this project the aforementioned forecast was requested from Alberta Energy, but it was not available for use in this work. Therefore, an alternative forecast was developed, on the basis of publicly available data from several sources (Alberta Chamber of Resources, 2004, Alberta Employment Integration and Industry, 2007, Ross Smith, 2008, Dunbar, 2008). The forecast was divided according to operation, including mining, SAGD, and upgrading production.

Tables 2.1 to 2.3 list all the oil sands facilities considered in the forecast. Overall, upgrading operations have listed 5 companies while mining and SAGD included 9 and 19 companies, respectively. SAGD bitumen accounts for most of the increase in bitumen production capacity in the province, which is consistent with published estimates (National Energy Board, 2007).

Table 2.1. Mined bitumen projects in the Fort McMurray area 2005-2020

Company	Project(s)	Cumulative capacity (bpd)
AOSP	Muskeg River, Jackpine, Pierre River	670,000
CNRL	Horizon	577,000
Imperial/Exxon Mobil	Kearl Lake	300,000
Petro Canada	Fort Hills	165,000
Suncor	Millenium, Steepbank, Voyageur	441,000
Syncrude	Mildred Lake, Aurora	593,000
Synenco	Northern Lights	114,500
Total E&P	Joslyn	150,000
UTS/Teck Cominco	Equinox, Frontier	210,000

The data corresponding to each producer is organized according to the year when the project is expected to come on-stream and to its operational status. This is done to account for uncertainties in oil production levels over time. The project status categories (current as of April, 2008) include:

- Operating – the project is currently extracting or upgrading bitumen
- Construction – the project is currently under active construction
- Approved – approval from AEUB has been granted
- Application – an application for proposed operations has been submitted
- Disclosure – specific details of the project have been made public
- Announced – a future project has been announced, minimal details are given

On the basis of the above categories, three forecast levels were specified:

- Low – includes all projects currently operating or under construction
- Medium – includes low plus approved and application projects
- High – includes all project status categories

The low, medium and high refer to production level. Thus, the likelihood of all projects coming on stream in any given year reflected the confidence level of the forecast. In other words, projects in the "announced" and "disclosure" categories increase the production potential in any given year while being themselves inherently more uncertain to reach "operating" status than for instance, "approved" projects. The analysis presented in this Study provides a range of anticipated oil and CO_2 production levels, which increases the usefulness of the forecasts.

Table 2.2. SAGD bitumen projects in the Fort McMurray area 2005-2020

Company	Site(s)	Cumulative capacity (bpd)
Chevron Canada	Ells River	100,000
CNRL	Birch, Kirby, Gregoire Lake	180,000
Connacher	Great Divide	20,000
Conoco-Phillips	Surmont	100,000
Devon	Jackfish	70,000
Encana	Borealis, Christina Lake, Foster Creek	433,800
Enerplus	Kirby	35,000
Husky	Sunrise	200,000
JACOS	Hangingstone	60,000
KNOC	Black Gold	10,000
MEG	Christina Lake	23,880
Opti-Nexen	Long Lake	356,000
Patch	Ells River	10,000
Petro Canada	MacKay River	73,000
Petrobank (Whitesands)	May River	10,000
StatoilHydro	Kai Kos Dehseh	220,000
Suncor	Firebag	367,000
Total E&P	Joslyn	42,000
Value Creation	Terre de Grace	10,000

Table 2.3. Upgrading (SCO) projects in the Fort McMurray area 2005-2020

Company	Site(s)	Cumulative capacity (bpd)
CNRL	Horizon	497,000
Opti-Nexen	Long Lake	292,500
Suncor	Base mine, Millenium, Voyageur	547,000
Syncrude	Mildred Lake, Aurora	510,000
Value Creation	Terre de Grace	8,400

Once the oil production forecast was completed, the CO_2 emissions of each of the processes/products were determined. These emissions are a function of the energy conversion processes involved in mining, SAGD, and upgrading. Accordingly, the CO_2 emissions are broken down into energy commodities, as shown in Figure 2.1. Different processes/products require different energy commodities, which ultimately determine the overall CO_2 intensity and emissions in any given year.

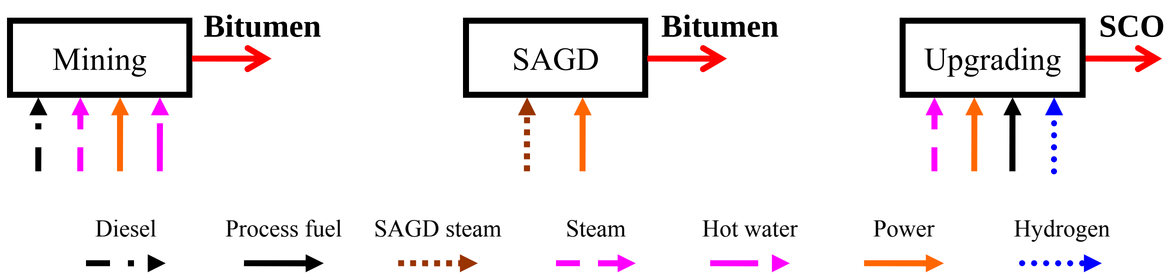

Figure 2.1. Energy demands of oil sands operations by commodity

The input parameters relating SCO and bitumen production to energy demands and CO_2 emissions were derived from the Oil Sands Optimization Model (OSOM) a stand-alone mathematical model designed to quantify energy demands and emissions of oil sands operations (Ordorica-Garcia et. al., 2007). The specifics concerning modelling of CO_2 emissions are discussed in (Ordorica-Garcia et. al., 2007) and in Section 2.2, of this chapter.

Of all the CO_2 emissions from oil sands operations, only a fraction can be feasibly recovered. In this study, a unique "capturable" fraction is assigned to individual CO_2 streams from different processes (e.g., power, steam, hydrogen production). The capturable CO_2 is a function of the carbon removal technology used, the flue gas compositions, and inherent process limitations. For capture technologies, capture efficiency is assumed to be 90%. Thus, the overall CO_2 emissions and the "capturable" CO_2 emissions are reported. The latter constitute the actual potential CO_2 supply in the region. In the analyses, the supply is sub-divided into CO_2 from mining, SAGD, and upgrading operations. All non-stationary CO_2 sources (for example, mobile vehicles) are assumed not capturable.

Finally, the CO_2 supply forecast is also provided as a function of the purity of the CO_2 streams generated from oil sands operations. The CO_2 concentrations of flue gases resulting from producing different energy commodities were determined by first-principles modelling and from the literature. The supply of CO_2 streams with various concentrations was thus determined. These concentrations range from less than 10% to roughly 50% (mole, dry basis). There are also high purity CO_2 streams (95+%) from three Benfield units in the Fort McMurray area.

2.2 ASSUMPTIONS

As the CO_2 production is a direct function of oil production, the consistency of the oil forecasts is very important. Although it is impossible to predict the actual production levels that will be observed in the future, every effort was made to incorporate the latest and most thorough data in the oil forecasts. The data used in this Study is current as of April, 2008. The projects included in the forecasts are listed in Tables 2.1 to 2.3. Their stated output and anticipated on-stream dates were tabulated and categorized by status to generate the forecasts shown later in this Chapter. The individual project forecasts are also provided (see Appendix 1).

In certain instances, some oil production was excluded from the forecasts. There are two main reasons for this: 1) the on-stream date is unknown and 2) the on-stream date specified fell outside the timeframe of the analysis. These conditions, though rare, warranted the exclusion of these projects/project phases from the forecast, for consistency's sake. Further, the fact that a project does not have a start-up date is a strong indication of its highly uncertain nature. The individual excluded projects are listed in Table 2.4. Excluded mining and upgrading projects are few, and in our view, would have a limited impact on the shape of the supply curves, if they are eventually brought on-stream. This is mainly because it is unlikely that all of them would begin operations at the same time. The uncertainty is highest on SAGD projects, where a more significant production capacity may or may not come on stream within the timeframe under study.

Table 2.4. Summary of projects excluded from the oil production forecast

Company	Site(s)	Category	On-stream date	Capacity (bpd)
AOSP	Pierre River	Mining	2021	100,000
Petro Canada	Fort Hills	Mining	TBD	25,000
Total E&P	Joslyn	Mining	2022	50,000
CNRL	Gregoire Lake	SAGD	2023	30,000
CNRL	Leismer	SAGD	2025	15,000
Encana	Borealis	SAGD	TBD	65,000
KNOC	Black Gold	SAGD	TBD	20,000
Opti-Nexen	Long Lake	SAGD	2022	72,000
Petro Canada	Lewis	SAGD	TBD	80,000
Petro Canada	Chard	SAGD	TBD	40,000
Petro Canada	Meadow Creek	SAGD	TBD	80,000
Petrobank/Whitesands	May River	SAGD	TBD	90,000
StatoilHydro	Kai Kos Dehseh	SAGD	2034	20,000
Value Creation	Terre de Grace	SAGD	TBD	80,000
Opti-Nexen	Long Lake	Upgrading	2022	58,500
Value Creation	Terre de Grace	Upgrading	TBD	67,200

The CO_2 production from mining bitumen extraction considers the emissions from diesel, hot water, steam, and power production. SAGD extraction includes emissions from steam and power only, whereas upgrading operations comprise the emissions from process fuel, steam, power, and hydrogen production.

The assumed energy demands in terms of the aforementioned commodities for individual oil sands operations are presented in Table 2.5. These parameters are obtained from the OSOM (Ordorica-Garcia et. al., 2007). Hence, mined bitumen operations cover mining oil sands, hydro-transport/conditioning of the oil sands slurry, and bitumen extraction via the hot water process. SAGD operations consider steam injection, fluid production and bitumen separation. Upgrading operations cover bitumen distillation (atmospheric and vacuum), coking (fluid and delayed), Hydrocracking via LC-Fining, and Hydrotreatment for Sulphur and Nitrogen removal.

In this Study, as well as in the OSOM, it is assumed that *natural gas is used* for power, steam, hot water, and hydrogen production. Hydrogen is alternatively produced from bitumen residues (asphaltene and petcoke) via gasification. Diesel is used as fuel in mining operations. Therefore, the CO_2 emissions and supply forecasts are built on the basis of utilization rates of each of the fossil fuels previously described.

Table 2.5. Main energy demand parameters used in the CO_2 supply forecasts

	Diesel l/bbl	Hot water tonne/bbl	Steam tonne/bbl	Power kWh/bbl	Process fuel MJ/bbl	Hydrogen SCF/bbl
Mining	1.71	1.08	0.01	16.4		
SAGD			0.39	3.1		
Upgrading			0.10	6.3	59	2,000

The impact of energy production in oil sands operations on CO_2 emissions intensity is summarized in Table 2.6. In general, bitumen upgrading has the highest CO_2 intensity of all processes reviewed in this study, followed by SAGD extraction and bitumen mining operations. In the case of hydrogen production and use, the CO_2 intensity figures are given as a range. This merely reflects the various feedstocks available for hydrogen production, which in this study are natural gas, petroleum coke (petcoke) and pitch.

Table 2.6. CO_2 emissions/production parameters according to oil production and commodity

	Diesel	Hot water	Steam	Power	Process fuel	Hydrogen	Total
				tonnes CO_2 /bbl			
Mining	0.005	0.006	0.002	0.006			0.018
SAGD			0.053	0.001			0.054
Upgrading			0.017	0.002	0.003	0.041-0.111	0.063-0.133

The CO_2 capture technologies applied in the analysis are a function of the CO_2 concentration in the flue gases from bitumen mining, upgrading, and SAGD extraction. Table 2.7 summarizes the technologies considered in this study, the typical CO_2 concentrations of all energy commodities under study, and assumed CO_2 capture rates.

Table 2.7. CO_2 capture technologies applied to individual energy commodities

	Diesel	Hot water	Steam	Power	Process fuel	Hydrogen
CO_2 content in flue gas (mole %)	10-15%	0-10%	0-10%	10-15%	0-10%	15-50%
CO_2 Capture technology	N/A	A,C	A,C	A,C	A,C	A,B
Capture rate[1]	N/A	90%	90%	90%	90%	85-95%

A: Post-combustion CO_2 capture via MEA scrubbing B: Pre-combustion CO_2 capture via Selexol scrubbing
C: Oxy-combustion with CO_2 recovery (not commercial yet)
[1] As a percentage of total CO_2 produced

Due to their low CO_2 partial pressure, combustion flue gases from boilers, heaters, and natural gas power plants require a chemical absorption process for CO_2 removal. The same applies for steam methane reforming (SMR) hydrogen plants. Alternatively, the combustion units above could be fired with oxygen, yielding a highly concentrated CO_2 stream, which can be recovered after dehydration. This technology, called oxyfuel combustion, though attractive, is not commercially available yet. Thus, for the purposes of this analysis, post-combustion CO_2 capture is the preferred method for flue gases in the 0-15% concentration range. On the other hand, gasification-based hydrogen plants are assumed to employ a physical solvent for CO_2 capture, due to their higher partial CO_2 pressures.

2.3 OIL PRODUCTION FORECASTS

The oil production is subdivided according to process. Table 2.8 shows mined bitumen production while Tables 2.9 and 2.10 correspond to thermal bitumen and upgrading, respectively. The reader must be aware that the upgrading production values presented in Table 2.10 represent a portion of the mined and SAGD bitumen production from Tables 2.8 and 2.9. The purpose of the forecasts is to provide a basis to estimate the demand for fossil energy for mining, SAGD, and upgrading, rather than to give a precise breakdown between bitumen and SCO production. An approximation to these values can be obtained by using equations (1) to (3) for a given year and scenario:

Bitumen production ≈ (mined bitumen + SAGD bitumen) – upgrading (1)
SCO production ≈ upgrading (2)
Total oil production ≈ mined bitumen + SAGD bitumen (3)

Among products, mined bitumen has the highest absolute production growth, followed by thermal bitumen and upgrading. In the low production scenario, both mined bitumen and upgrading roughly double between 2005 and 2020 whereas thermal bitumen increases roughly five-fold in the same period. By 2020, the production figures total 1.1 million barrels, 0.5 million barrels, and 0.9 million barrels per day for mined bitumen, thermal bitumen, and upgrading (SCO), respectively.

The low scenario is very conservative when compared to the medium case. In the latter scenario, thermal bitumen production increases by a factor of 20 between 2005 and 2020 while the increase for mined bitumen is four-fold. Upgrading production triples in the same period. In absolute terms, however, by 2020, mined bitumen accounts for the majority of the production at 2.4 million barrels, compared to 1.6 million barrels for thermal bitumen and 1.2 million barrels of upgrading (SCO) capacity.

The high production scenario is inherently more uncertain than the other two. However, the resulting production forecast grows almost uninterruptedly from year to year, unlike the low or medium cases, where periods of growth are often interspersed with years of stable production. Between 2005 and 2020, in the high production scenario, mined bitumen goes from 0.6 to 3.2 million barrels per day. Thermal bitumen grows from 0.08 to 2.3 million barrels per day while daily upgrading capacity expands from 0.4 to 1.8 million barrels of SCO.

Table 2.8. Mined bitumen production forecast 2005-2020 (kbbl/d)

Scenario	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	613	822	860	1,018	1,018	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118	1,118
Medium	613	822	860	1,018	1,018	1,390	1,810	2,068	2,118	2,218	2,218	2,268	2,268	2,468	2,468	2,468
High	613	822	860	1,018	1,018	1,390	1,857	2,114	2,164	2,314	2,699	2,749	2,971	3,171	3,221	3,221

Table 2.9. Thermal bitumen production forecast 2005-2020 (kbbl/d)

Scenario	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	85	200	275	395	473	473	473	473	473	473	473	473	473	473	473	473
Medium	85	200	275	450	583	756	1,009	1,167	1,207	1,392	1,427	1,567	1,587	1,657	1,657	1,657
High	85	200	275	450	593	801	1,079	1,292	1,392	1,637	1,802	2,002	2,077	2,219	2,219	2,321

Table 2.10. Upgrading production forecast 2005-2020 (kbbl/d)

Scenario	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	412	610	626	880	880	880	880	880	880	880	880	880	880	880	880	880
Medium	412	610	626	880	880	1,015	1,133	1,196	1,196	1,254	1,254	1,254	1,254	1,254	1,254	1,254
High	412	610	626	880	880	1,015	1,133	1,196	1,236	1,294	1,419	1,478	1,738	1,796	1,796	1,855

On an annual growth basis, thermal bitumen is poised to experience the largest expansions between 2005 and 2020. Its year-to-year average production rise is 37%, 130%, and 182%, for the low, medium, and high scenarios, respectively. Mined bitumen and upgrading production grows at much more moderated and remarkably similar rates. The annual growth figures for the former are 12%, 27%, and 35% and 14%, 20%, and 30% for the latter, for the low, medium, and high production scenarios, respectively.

From an energy demand perspective, the anticipated growth outlined above will result in a dramatic increase in steam, power, and hydrogen production in oil sands operations. To a lesser extent, hot water, and diesel fuel will also be affected by high mining operations growth. This situation will drive the demand for fossil fuels higher, in line with the oil forecasts previously presented. Although there are clear opportunities to use by-products of upgrading for energy production, their contribution to the overall energy demands of the oil sands industry will be insufficient. Thus, to sustain the growth of oil sands operations, significant amounts of externally-supplied fuels, namely natural gas and likely coal, will be required.

2.4 CO_2 SUPPLY FORECASTS

In this section, the CO_2 supply associated with the oil production forecasts covered earlier will be presented. First, the CO_2 supply according to product will be given, for the low, medium, and high production cases. The second half of this section will detail the total CO_2 supply and provide a breakdown of the supply by source and quality.

2.4.1 Mined bitumen

Figures 2.2 to 2.4 show the CO_2 production forecasts for mined bitumen for the three scenarios under study. In the low scenario, the maximum total CO_2 production is 20,000 tonnes/d. In the medium and high scenarios, the CO_2 production peaks at 45,000 and 58,000 tonnes CO_2/d, respectively, by 2020. However, only two thirds of the total CO_2 produced is deemed "capturable". This is due to the significant emissions resulting from diesel fuel use in mining operations and the maximum feasibly recoverable CO_2 level in boilers and power plants. Hence, the actual maximum supply (or "capturable" CO_2) is 13,000, 30,000, and 39,000 tonnes CO_2/d for the low, medium, and high cases.

The CO_2 supply profile of the low case differs drastically from those of the medium and high cases. In the former, the CO_2 production plateaus in 2010 and remains unchanged until 2020. In the medium and high scenarios, a moderate period of growth between 2005 and 2009 is followed by an explosive annual growth of 27% and 35% in CO_2 supply, respectively until 2020.

2.4.2 Thermal bitumen

In the case of thermal bitumen, maximum CO_2 production in the year 2020 ranges from 25,000 tonnes/d to 126,000 tonnes/d for the low and high scenarios, respectively.

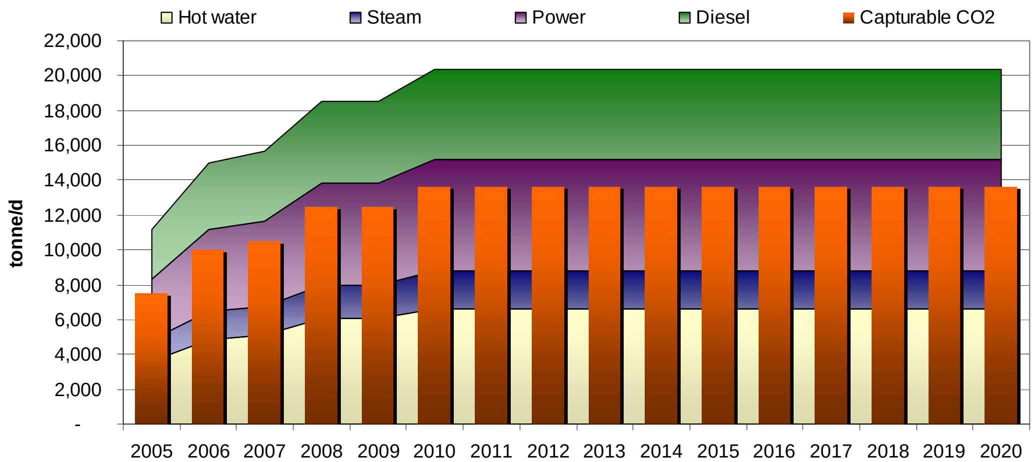

Figure 2.2. CO_2 supply from mined bitumen production 2005-2020 - Low

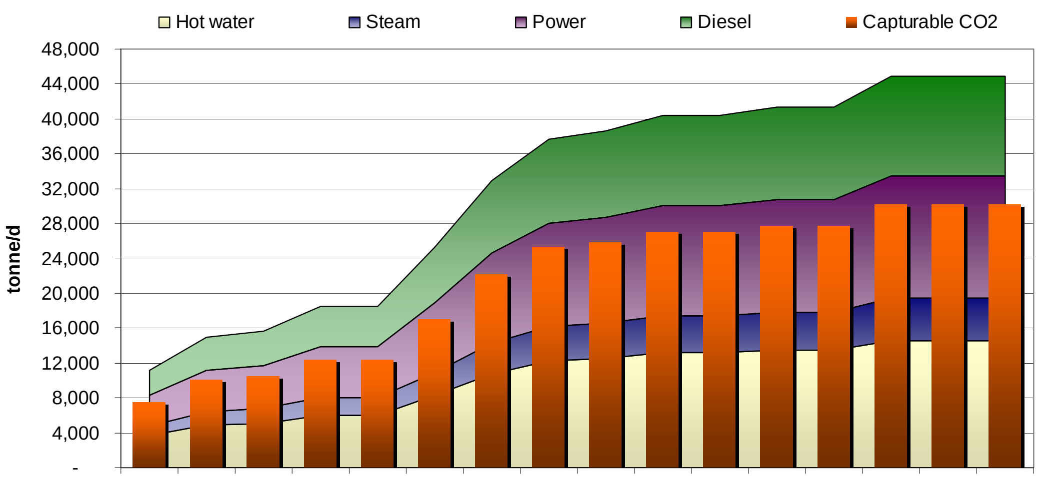

Figure 2.3. CO_2 supply from mined bitumen production 2005-2020 - Medium

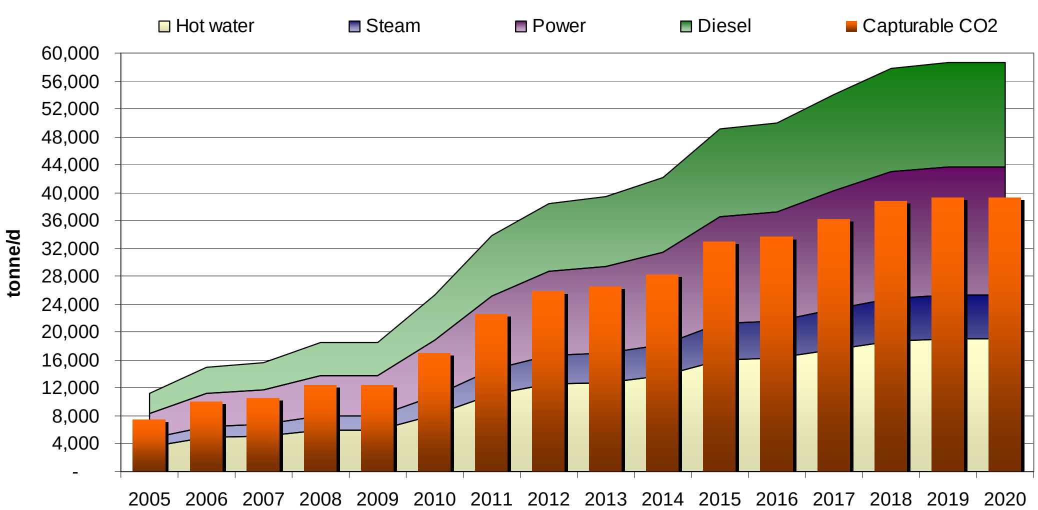

Figure 2.4. CO_2 supply from mined bitumen production 2005-2020 - High

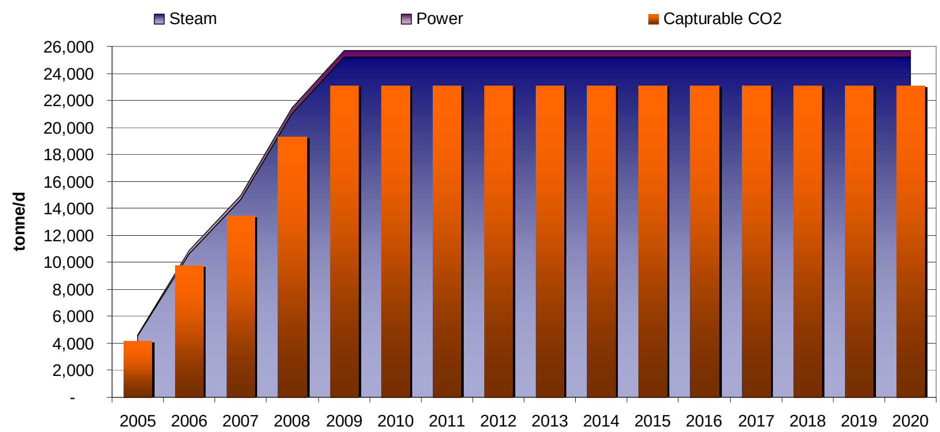

Figure 2.5. CO_2 supply from thermal bitumen production 2005-2020 - Low

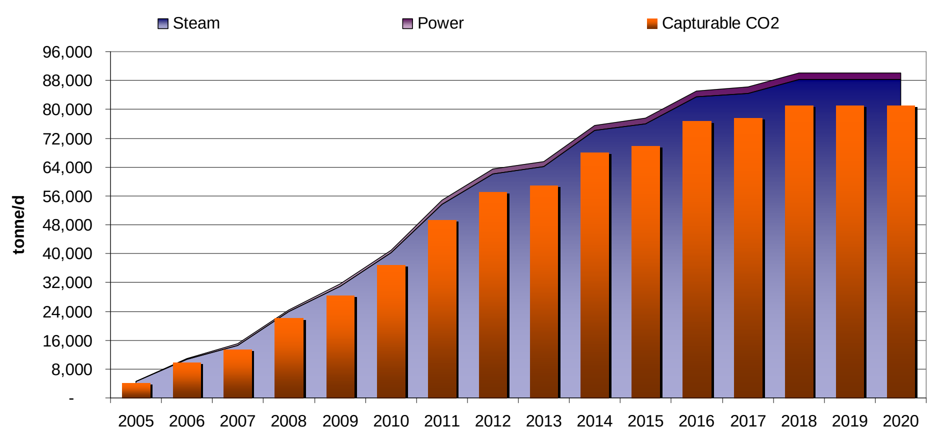

Figure 2.6. CO_2 supply from thermal bitumen production 2005-2020 - Medium

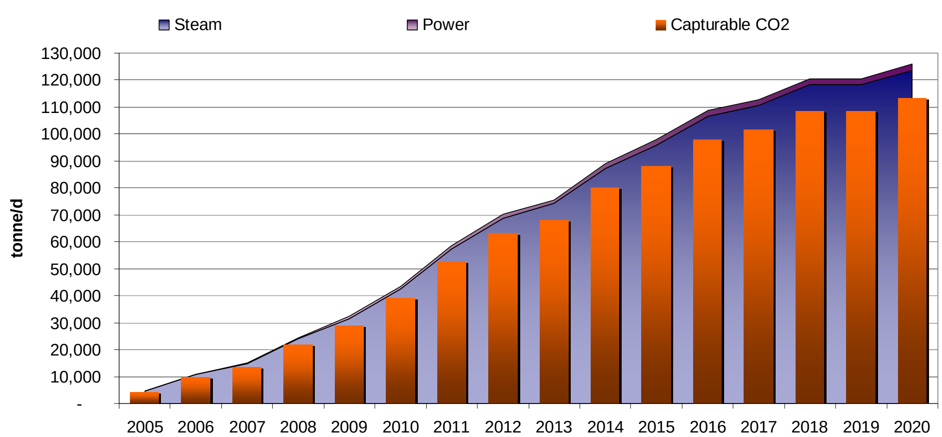

Figure 2.7. CO_2 supply from thermal bitumen production 2005-2020 - High

The capturable CO_2 figures are 23,000, 81,000, and 113,000 tonnes/d for the low, medium, and high thermal bitumen scenarios, which equals to a 90% CO_2 recovery level. The potential CO_2 supply from thermal bitumen operations is significantly higher than that from mined bitumen, as seen in Figures 2.5 to 2.7.

The shape of the CO_2 supply curves for thermal bitumen production is set by the emissions resulting from steam generation, whereas for mined operations, steam accounts for roughly 10% of the total CO_2 production. Although not addressed in this study, the flue gas produced from thermal operations is likely to be more dispersed than that of mined or upgrading operations, thus presenting a bigger challenge to CO_2 capture.

In the low scenario, CO_2 supply grows at an elevated yearly rate between 2005 and 2009 (139%), but remains unchanged thereafter. In the medium and high scenarios, the annual CO_2 supply grows steadily at an average rate of 130% and 182%, correspondingly, between 2005 and 2020.

2.4.3 Upgrading (SCO)

The CO_2 supply from bitumen upgrading is largely determined by the extent of hydrogen production and the technology used. In this analysis, the baseline CO_2 supply is calculated on the basis of SMR technology. If gasification is used instead of SMR, the additional potential CO_2 supply is presented separately. In the low production case, baseline CO_2 supply peaks at 51,000 tonnes/d ("Capturable CO_2" columns in Figure 2.8). However, if H_2 production via gasification is used, the potential supply could reach 102,000 tonnes CO_2/d by 2020, as indicated by the "variable H_2" columns in Figure 2.8.

In the medium production scenario, total baseline CO_2 supply increases from 24,000 to 73,000 tonnes/d between 2005 and 2020 (see Figure 2.9). The potential additional supply if gasification of pitch or petcoke is implemented is almost identical to the baseline figures for all the years. Thus, the maximum potential CO_2 supply from upgrading processes is 48,000 and 146,000 tonnes/d between 2005 and 2020, if gasification of upgrading residues is used for hydrogen production instead of natural gas-based SMR.

In the high scenario, the baseline CO_2 supply grows from 24,000 tonnes/d in 2005 to 109,000 tonnes/d in 2020. Similarly to the other scenarios, the potential CO_2 supply doubles if gasification technology is used for H_2 production, peaking at 216,000 tonnes of CO_2/d in 2020, as seen in Figure 2.10.

The total CO_2 supply experiences the highest annual growth (53%) between 2005 and 2008 in the low scenario, and stagnates afterward. In the medium and high production scenarios, the CO_2 supply grows at an average annual rate of 20% and 30%, respectively until 2020. The CO_2 curve is identical for the former two scenarios between 2005 and 2012. From that point onward, however, the CO_2 supply in the medium scenario plateaus in 2014 whereas the high scenario continues to grow until 2020.

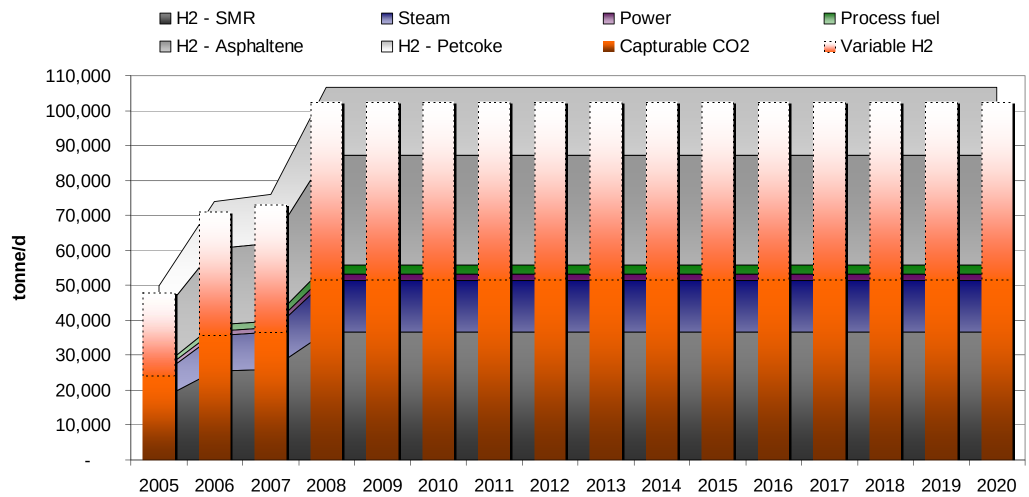

Figure 2.8. CO_2 supply from upgrading (SCO) production 2005-2020 - Low

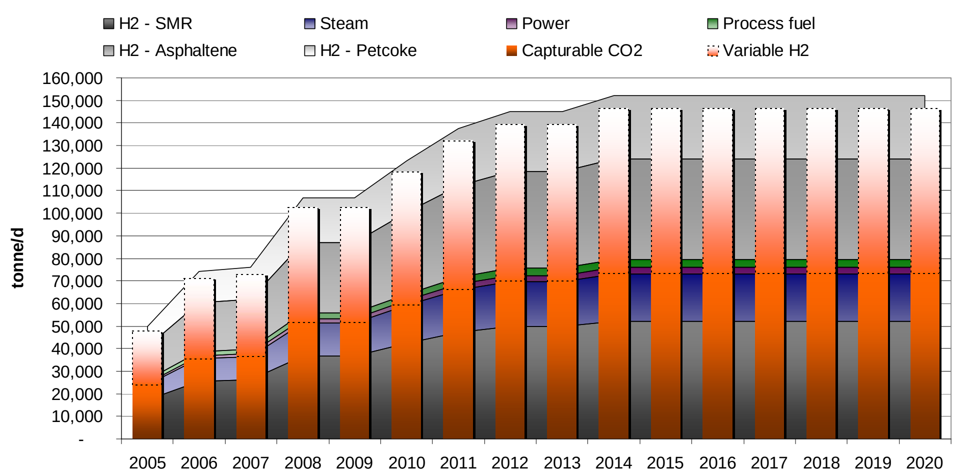

Figure 2.9. CO_2 supply from upgrading (SCO) production 2005-2020 – Medium

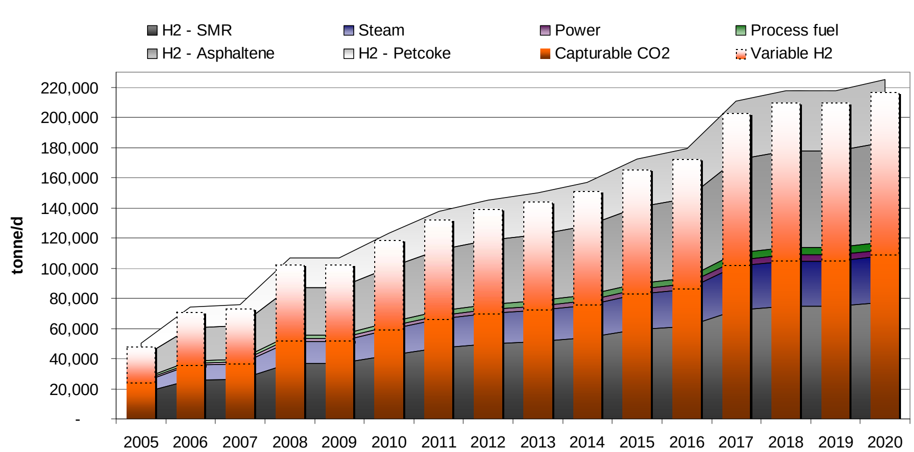

Figure 2.10. CO_2 supply from upgrading (SCO) production 2005-2020 – High

The recoverable CO_2 potential is the highest for upgrading, at 93-96% of total CO_2 production. SAGD production is second with 90% recovery potential while mining operations have the lowest CO_2 recovery potential at 67% of total CO_2 production.

2.4.4 Total CO_2 supply

Overall, upgrading operations contribute the most to CO_2 emissions growth, followed by thermal (SAGD) and mining production, for all cases, as shown in Figures 2.11, 2.12, and 2.13. In the low scenario, CO_2 supply increases from 35,000 tonnes/d to 88,000 tonnes/d between 2005 and 2010 and remains unchanged until 2020. If gasification technology is used for H_2 production, an additional 24,000 – 51,000 tonnes CO_2/d are available between 2005 and 2020. Hence, depending on the fuel choice, maximum CO_2 supply in the low scenario ranges from 88,000 to 139,000 tonnes/d between 2010 and 2020, as seen in Figure 2.11.

In the medium growth scenario, CO_2 supply assuming SMR for H_2 production grows at an average annual rate of 34%, reaching 184,000 tonnes/d by 2020. An additional 24,000 – 73,000 tonnes CO_2/d could be available due to the implementation of gasification of bitumen residues, setting the maximum CO_2 supply at 257,000 tonnes/d by 2020.

The CO_2 supply in the high production scenario is drastically higher than that of the other cases. CO_2 availability peaks in 2020 at 261,000 tonnes/d, up from 36,000 tonnes/d in 2005. The average annual increase in CO_2 supply in the above timeframe is 49%, excluding gasification. If gasification of bitumen residues is considered, CO_2 supply increases between 24,000 and 107,000 tonnes CO_2/d between 2005 and 2020. Thus, the maximum daily CO_2 supply reaches 369,000 tonnes CO_2 in 2020.

Overall CO_2 capture potential is 87%-91% for the low scenario and 86%-90% for the medium and high scenarios. The lower end of the above ranges corresponds to the recoverable CO_2 from all sources, excluding gasification, whereas the high end considers gasification.

2.4.5 CO_2 supply according to commodity

The total CO_2 supply for mining, SAGD, and upgrading operations is largely determined by two commodities: steam and H_2, regardless of scenario. Figures 2.14, 2.15, and 2.16 shows the breakdown of CO_2 emissions and supply for the low, medium, and high production scenarios, respectively. The total CO_2 production figures are identical to the values presented in the previous section, but are sub-divided by commodity in this section.

In the low scenario, the CO_2 production from steam generation accounts for 28% of the total, while CO_2 from H_2 production via SMR represents 24%. Power generation is third, at 6%, while hot water, process fuel, and diesel together contribute less than 10% of total CO_2 production. If gasification of asphaltene is used, CO_2 from hydrogen production increases to 45% of total CO_2 supply. Using petcoke instead of asphaltene as a feedstock increases the previous figure to 58% of total CO_2 production.

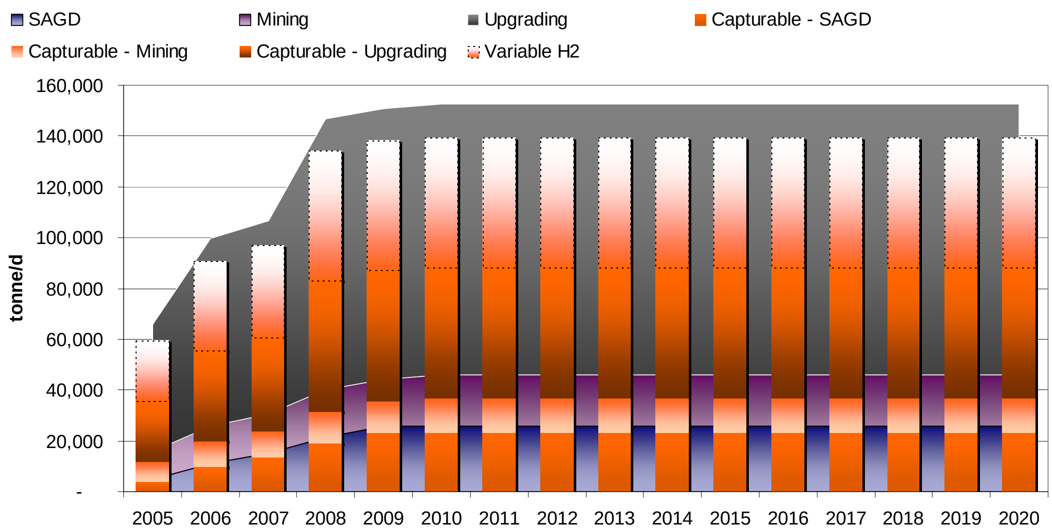

Figure 2.11. Total CO_2 supply in Ft. McMurray 2005-2020 – Low

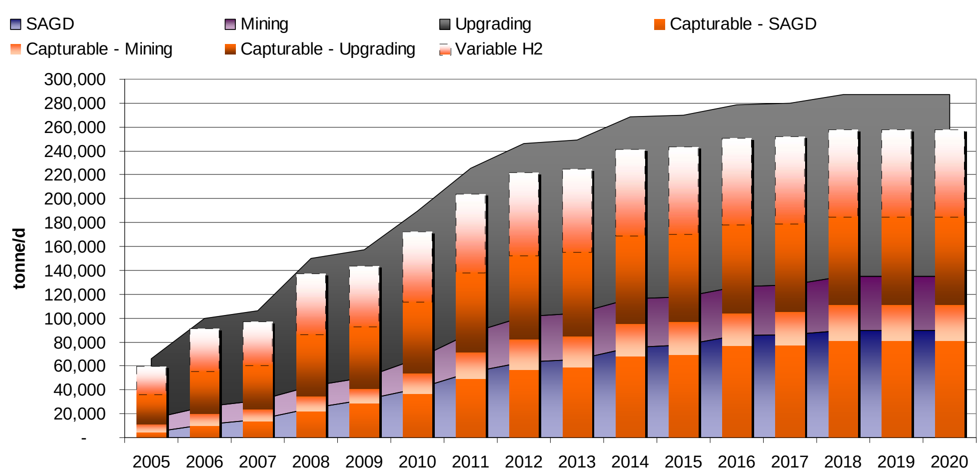

Figure 2.12. Total CO_2 supply in Ft. McMurray 2005-2020 – Medium

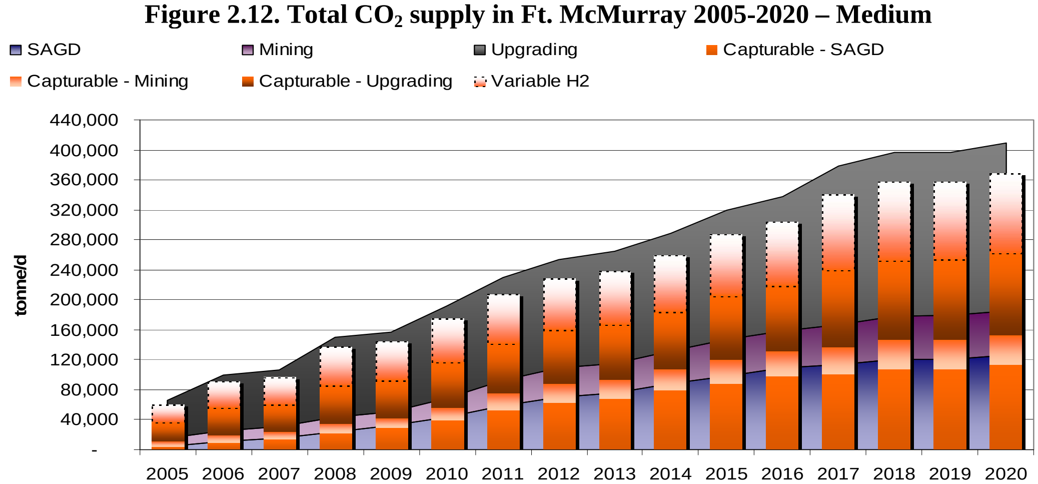

Figure 2.13. Total CO_2 supply in Ft. McMurray 2005-2020 – High

In the medium scenario, CO_2 from steam generation is roughly twice as much as that associated with H_2 production if natural gas is used as a feedstock (40% vs. 18% of total CO_2 production). But, if gasification of upgrading residues is used, H_2 manufacture becomes the main source of CO_2, reaching 45% of the total CO_2 production. Power, hot water, process, and diesel fuel combined account for roughly 16% of CO_2 production. Although the shapes of the curves for the high scenario are different than those of the medium scenario, its breakdown of CO_2 production is almost identical to that of the latter (see Figures 2.15 and 2.16).

The analysis revealed that the total CO_2 supply (excluding gasification) is roughly equivalent to the combined emissions from steam, hydrogen, and power production. The magnitude of the combined CO_2 emissions associated with hot water production, diesel, and process fuel use roughly correspond to the non-capturable CO_2 in oil sands operations. The total "capturable" CO_2 increases if gasification technology is considered, as indicated by the "variable H_2" bar in Figures 2.14 to 2.16.

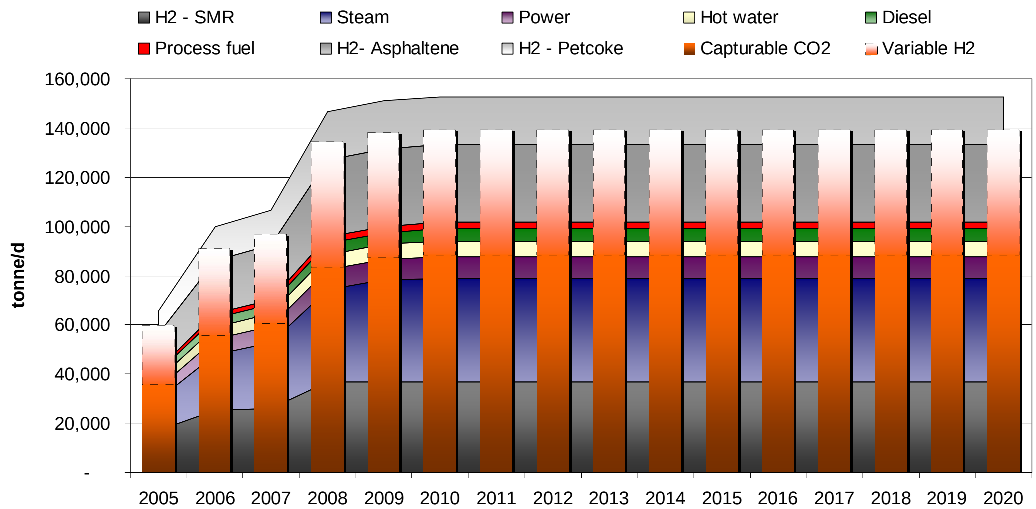

Figure 2.14. CO_2 supply by commodity in Ft. McMurray 2005-2020 – Low

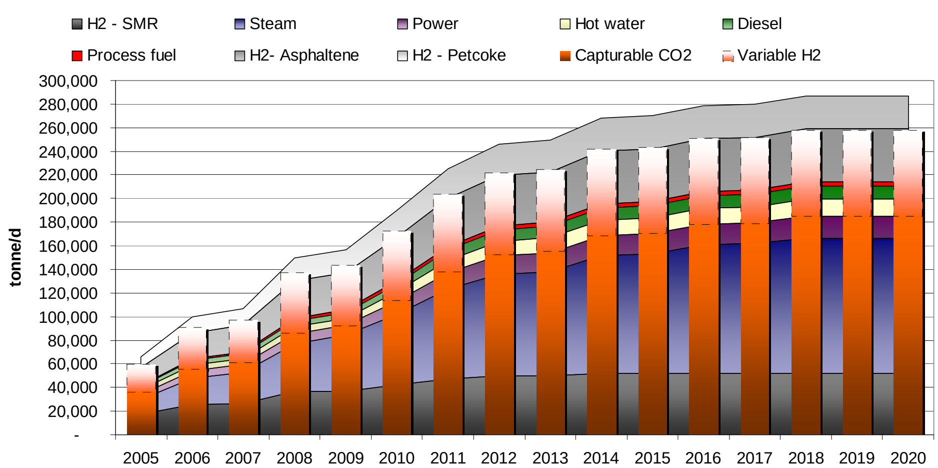

Figure 2.15. CO_2 supply by commodity in Ft. McMurray 2005-2020 – Medium

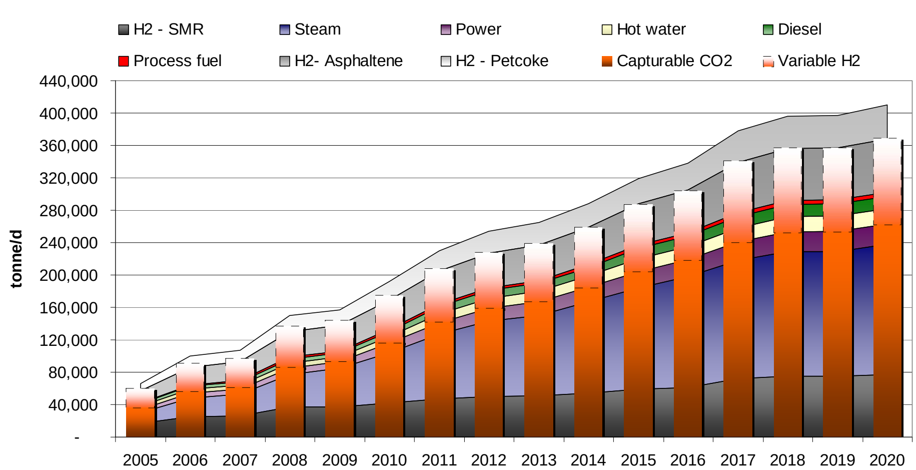

Figure 2.16. CO_2 supply by commodity in Ft. McMurray 2005-2020 – High

2.4.6 CO_2 supply according to purity

Figures 2.17, 2.18, and 2.19 summarize the CO_2 production forecasts for the low, medium, and high production scenarios, respectively. The CO_2 produced is divided according to the mole fraction (dry basis) of CO_2 in the source gas stream. Accordingly, the possible purity ranges are: 0%-10%, 10%-15%, 15%-20%, and 30%-50%. The CO_2 from diesel fuel use in mining operations is excluded from the curves, as it wholly unrecoverable.

In the low case, CO_2 streams with a purity of less than 10% are the most abundant, reaching 51,000 tonnes/d in 2020. Streams with a CO_2 content between 15%-20% are second, increasing from 17,000 to 36,000 tonnes/d between 2005 and 2020 while 10%-15% purity sources amount to 4,500-9,000 tonnes/d in the same period. Gasification processes have the potential to generate between 68,000 and 87,000 tonnes of CO_2 per day with a concentration of 30%-50% by 2020. All of the above CO_2 streams increase between 2005-2009 and stabilize thereafter, as seen in Figure 2.17.

In the medium scenario, process streams under 10% purity are the largest source of CO_2 between 2005 and 2020, followed by 15%-20% streams and 10%-15% sources. The former CO_2 supply grows from 17,000 tonnes/d to 132,000 tonnes/d between 2005 and 2020. The production figures for the latter two sources are 17,000 – 52,000 tonnes a day and 4,500 – 19,000 tonnes CO_2/d, respectively, for the period between 2005 and 2020. High purity CO_2 sources from gasification range from 32,000 tonnes/d to 97,000 tonnes/d for asphaltene gasification and from 41,000 to 125,000 tonnes/d for petcoke gasification.

In the high production scenario, low-purity sources (0%-10%) and petcoke gasification gas streams (30%-50%) are the top sources of CO_2, reaching 185,000 tonnes/d by 2020. Between 2005 and 2013, the latter dominates, whereas post-2013 both sources have almost identical magnitudes, as seen in Figure 2.19. Medium-purity sources (15%-20%) are second at 17,000 – 77,000 tonnes/d while 10%-15% sources are last with CO_2 production levels of 4,500 – 25,000 tonnes/d between 2005 and 2020.

Generally speaking, the growth in low-purity (0%-10%) is primarily driven by growth in thermal bitumen extraction, while increases in medium (15%-20%) and high-purity (30%-50%) sources are tied to growth in upgrading operations. Power generation is the main driver for the growth in CO_2 sources with a purity range of 10%-15%.

Table 2.11 shows a forecast of CO_2 emissions according to purity range for the medium case. The low purity sources (0%-10%) are the most abundant, followed by gasification high purity streams. SMR-derived CO_2 streams, with a medium purity (15%-20%) are fourth while streams in the 10%-15% range are the least abundant of all.

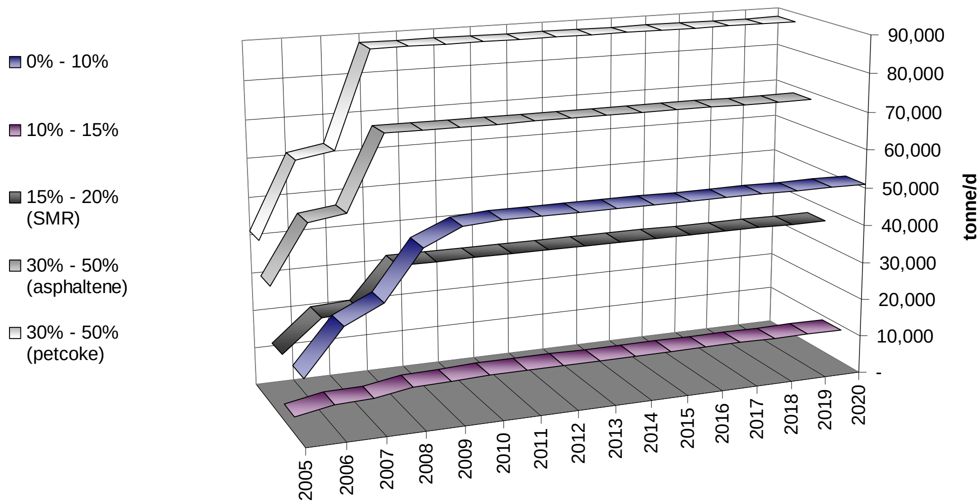

Figure 2.17. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – Low

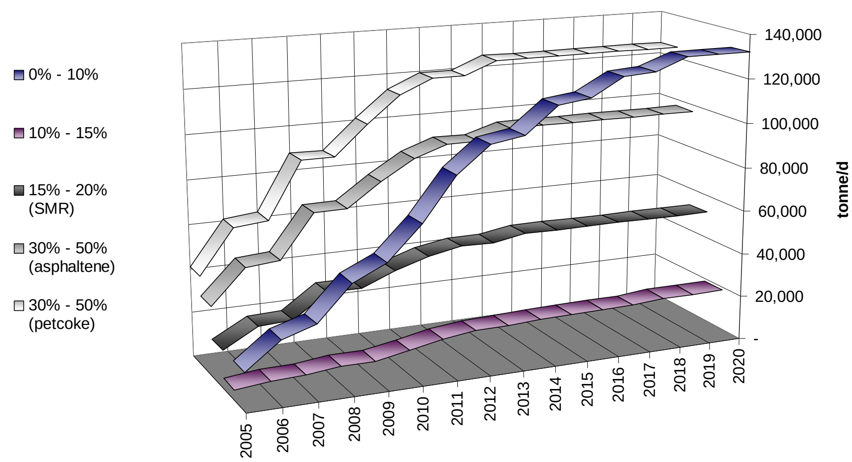

Figure 2.18. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – Medium

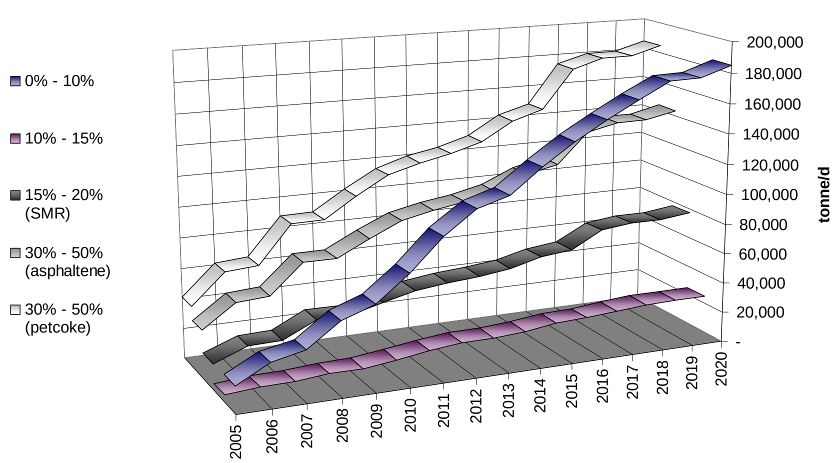

Figure 2.19. CO_2 supply according to source purity in Ft. McMurray 2005-2020 – High

Table 2.11. CO_2 supply forecast 2005-2020 (tonnes CO_2/d) – Medium case

Year	0% - 10%	10% - 15%	15% - 20% (SMR)	30% - 50% (asphaltene)	30% - 50% (petcoke)
2005	17,369	4,497	17,123	31,828	41,019
2010	70,940	10,984	42,226	78,488	101,152
2015	117,838	16,961	52,191	97,010	125,022
2020	132,049	18,638	52,191	97,010	125,022

Low purity sources are set to grow at an annual rate of 51%, increasing roughly by a factor of 8 between 2005 and 2020. Streams in the 10%-15% purity range grow 28% annually while the rest of the streams increase by 20% annually. The former CO_2 supply source rises by a factor of 4 and the latter by a factor of 3, between 2005 and 2020.

2.5 SUMMARY

When considering the potential CO_2 supply according to product, SCO has the highest recovery potential (93%-96% of total emissions) and the largest CO_2 production of all products (216,000 tonnes/d in 2020) *if gasification of bitumen residue is applied*. If gasification technology is not used, thermal (SAGD) bitumen yields the largest CO_2 supply (113,000 tonnes/d maximum) and a recovery potential of 90% of all CO_2 emissions. Although mined bitumen has higher production rates than the other products, its maximum potential CO_2 supply (39,000 tonnes/d by 2020) and recovery potential, at 67% of total CO_2 emissions, are low. Because the CO_2 emissions from diesel use in mining operations are associated with mobile sources, the overall CO_2 capture potential is lower than that of upgrading or thermal bitumen extraction, which are stationary sources.

In terms of the cumulative CO_2 supply between 2005 and 2020, upgrading operations have the largest contribution to CO_2 emissions growth, followed by SAGD and mining operations. The variability of CO_2 production in all scenarios is due to the feedstock choice for H_2 production. If asphaltene or petcoke are used instead of natural gas, the maximum CO_2 supply in the region escalates drastically. The maximum CO_2 supply is 88,000-139,000 tonnes/d in the low scenario, 184,000-257,000 tonnes/d in the medium case, and 261,000-369,000 tonnes/d in the high scenario. The overall CO_2 recovery potential ranges from 86% to 91% in all scenarios. The above figures correspond to peak production in 2020, where the high value corresponds to operations with gasification and vice versa.

The analysis reveals that the total CO_2 supply is largely determined by the production of steam and hydrogen, regardless of the scenario. Power generation has the third largest impact on CO_2 production, while the combined contribution of hot water, process fuel, and diesel use is roughly one-tenth of the total CO_2 supply. Across scenarios, steam generation contributes 24%-40% of total CO_2 production whereas H_2 production (if natural gas is used as fuel) accounts for 18%-24%. If gasification of asphaltene is used instead, the share of H_2 production rises to 35%-45% while gasification of petcoke yields 45%-58% of total CO_2 production.

Concerning the purity of the CO_2 sources, our findings indicate that low-purity sources (0%-10% CO_2) are the most abundant across scenarios. The maximum CO_2 production from the above sources varies between 51,000 – 185,000 tonnes/d by 2020. CO_2 stream with purity in the 15%-20% range are the next more abundant, when gasification is excluded, at 36,000 – 77,000 tonnes/d. CO_2 sources in the 10%-15% range are the smallest at 9,000 – 25,000 tonnes per day by 2020. High-purity sources (30%-50%) are only available if gasification of bitumen residues is considered. The maximum potential production by 2020 ranges from 68,000 to as much as 185,000 tonnes/d by 2020, depending on whether asphaltene or petcoke is used.

The growth in low-purity (0%-10%) CO_2 sources is primarily driven by growth in thermal bitumen extraction, while increases in medium (15%-20%) and high-purity (30%-50%) sources are tied to growth in upgrading operations. Power generation is the main driver for the growth in CO_2 sources with a purity range of 10%-15%.

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CHAPTER 3

CO_2 SUPPLY COST FOR THE LOW CONCENTRATION STREAMS

3.1 LOW CO_2 CONCENTRATION STREAMS

In this Chapter, we will deal with the waste gas streams of the category 0 - 10%, 10 – 15% and 15 – 20% CO_2.

There are a number of combustion flue gas streams in an oil sands extraction/upgrading setting:

- Exhaust from a gas turbine, typically with these compositions – 3.5% CO_2, 81.3% N_2, and 15.2% O_2 at 130°C and 120 kPa;
- Flue gas from a cracking or reformer furnace burning fuel gas, with these compositions – 9.2% CO_2, 87.1% N_2 and 3.7% O_2 at 200°C and atmospheric pressure;
- Flue gas from main stack with these compositions – 13% CO_2, 83.4% N_2, 3.6% O_2, 300 ppm S;
- Post-shift of a SMR with these compositions – 0.9% CH_4, 0.1% C_2H_6, 18.6% CO_2, 0.2% N_2, 78% H_2 and 2.1% CO.

3.2 CAPTURE PROCESSES

Since the waste gas stream is low in CO_2 concentration and under low pressure, the capture options are limited. Chemical absorption is the preferred option.

Alkanolamines have long been accepted in North America as the solvent of choice for the removal of hydrogen sulfide and carbon dioxide from process gas streams. Aqueous solutions of monoethanolamine (MEA) and diethanolamine (DEA) have been used extensively due to their reactivity, availability and low cost.

A typical amine absorption unit is shown in Figure 3.1. The gas stream and liquid amine solution are contacted by counter-current flow in an absorption tower. Conventionally, the gas to be scrubbed enters the absorber at the bottom, flows up, and leaves at the top, whereas the solvent enters the top of the absorber, flows down (contacting the gas), and emerges at the bottom. The absorber typically operates at 40 – 60°C. The liquid amine solution containing the absorbed gas then flows to a regeneration unit where it is heated and the acid gases liberated. The temperature at the regenerator typically ranges from 100 – 120°C. The solvent regeneration can be carried out at low pressures to enhance desorption of CO_2 from the liquid. Some amine solution is typically carried over in the acid gas stream from the regeneration step and the amine solution is recovered using a condenser. The hot lean amine solution then flows through a heat exchanger where it is contacted with the rich amine solution from the contact tower and from there the lean amine solution is returned to the gas contact tower.

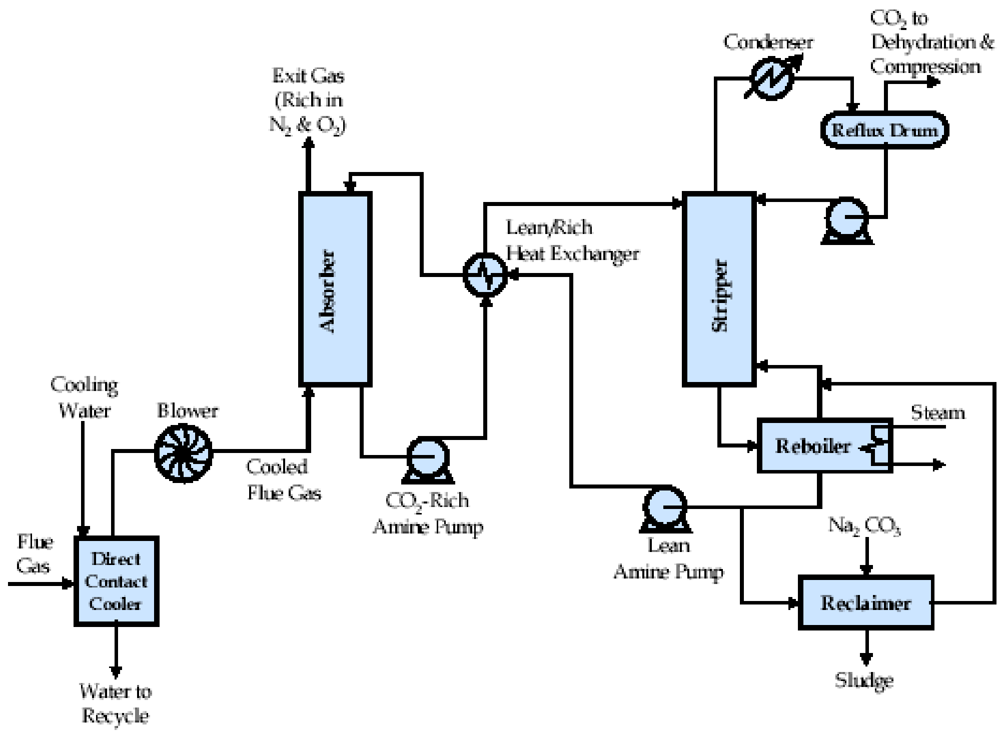

Figure 3.1: Typical amine absorption unit for CO_2 recovery from flue gas

The major issues in chemical absorption include:

- Solvent life
  - Requires very low SO_x (<10 ppm) and NO_2 (<20 ppm)
  - Reduces solvent losses as solvent can be expensive
- Corrosion
  - Stainless steel versus carbon steel
  - Inhibitors can contain heavy metals
- Energy consumption
  - Regeneration of the solvent consumes large amount of energy
- Environmental impacts
  - Some degradation products are known and regulated; others are not

Currently there are a range of technology suppliers with offerings to capture CO_2 from combustion flue gases. They are:

(a) Conventional Amine Processes

- Mitsubishi Heavy Industries (MHI) KS-1
- Fluor Econamine FG+^{SM}
- ABB Lummus Crest
- HTC PureEnergy
- Cansolv

(b) Ammonia Based Processes

- PowerSpan
- Alstom

3.2.1 Mitsubishi Heavy Industries

Mitsubishi Heavy Industries (MHI) has been involved in R&D related to CO_2 capture from flue gas since 1990. It has developed a proprietary, advanced solvent called KS-1 which believes to be a sterically hindered amine. The KS-1 solvent has many good properties – high rate of CO_2 absorption, lower solvent degradation, low corrosion and no requirement for a corrosion inhibitor. The first commercial plant using KS-1 is the Kedah urea plant at Kedah, Malaysia. It started operation in 1999. The feed gas is a natural gas reformer flue gas with a CO_2 concentration of 8%. The capacity is 200 tonnes per day. Plant performance so far has been good. The low pressure steam consumption is 1.5 tons/ton CO_2 recovered; solvent degradation is low.

As significant energy is consumed in the low pressure steam, MHI has made progress in reducing this steam consumption by recovering waste energy more efficiently. MHI shows that with the improved process, energy consumption is reduced by 15%. It means steam consumption reduces to 1.3 tons/ton of CO_2 (Ronald Mitchell and Masaki Iijima, 2008). One area that shows great potential is recovering energy from the condenser of the low pressure turbine (see Figure 3.2) and using it in the regenerator by incorporating additional plate heat exchangers.

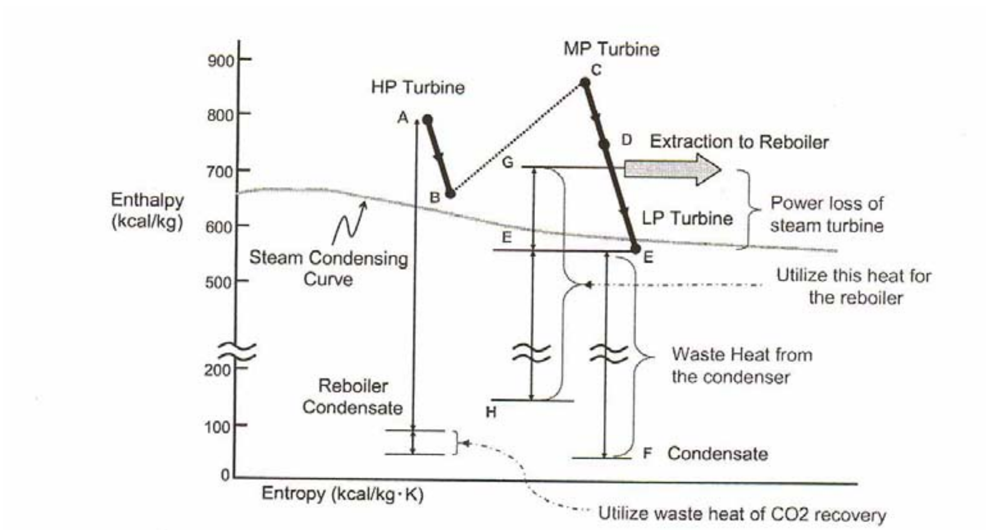

Figure 3.2: Options for heat integration based on the power plant steam cycle

MHI has been active in the commercial development of KS-1 plants. Other than the Malaysia Kedah, they have at least three more plant operating and three under licensing agreements:

- Japan, chemical company 330 tonnes/day started up 2005
- India fertilizer company 450 tonnes/day x 2 operating
- Adu Dhabi, fertilizer company 400 tonnes/day under construction
- Bahrain, 450 tonnes/day under construction
- Pakistan, fertilizer company, 340 tonnes/day just completed licensing agreement

These plants are all between 300 to 500 tonnes/day of CO_2, and all are capturing CO_2 from natural gas reformer flue gases. MHI has not built any plant capturing CO_2 from power plant flue gas. The concern is the SO_x and NO_x in the flue gas which could impact on the life of the KS-1 solvent. The further R&D seems to have resolved this issue and they are confident to move forward. They have completed a 3000 tonnes/day engineering feasibility study which means that this could be the next plant size. The limiting component for the single train, we believe, is probably the absorber.

3.2.2 Fluor Econamine FG+

Dow Chemical and Union Carbide initially developed the GAS/SPEC FT-1 process in the 1970s to capture CO_2 primarily for the EOR market. In 1989, Fluor Daniel purchased the technology and renamed it the Econamine FG^{SM} process. The process is based on an inhibited 30 wt% MEA solution. The inhibitor not only tolerates oxygen and NO_x containing flue gas but also required oxygen to maintain its activity.

The steam consumption is the most important component of the operating cost and is strongly influenced by the process design. It is reported that a well designed Econamine FG plant would use less than 4.2 GJ/t CO_2 (3.6 x10^6 BTU/ton). Electrical consumption is 2.45 kW/(t/d) or 60 kWh per tonne of CO_2 for a flue gas containing 8 vol% CO_2 (Chapel et al., 1999).

Fluor is continuously improving the Econamine process to lower energy consumption and solvent losses (Satish Reddy and John Gilmartin, 2008). A number of advanced features are available to customize each project:

- Enhanced solvent formulation – Econamine FG+ has improved solvent designed with MEA concentration > 35 wt% (versus 30 wt% for Econamine FG and 18-20 wt% for generic MEA). Higher MEA concentration increases reaction rates (less absorber packing required) and solvent carrying capacity (lower solvent circulation rates and steam requirements).
- Flue gas pre-treatment – removal of SO_x, NO_2 and particulates from flue gas is essential for minimizing solvent losses. Integration with the power plant desulphurization unit can potentially reduce capital cost.
- Absorber intercooling – heat is released in absorber due to heat of reaction. Intercooling produces a lower temperature at the bottom of the absorber which increases the solvent carrying capacity and CO_2 absorption rate.
- Lean vapor compression at the regeneration column – lower steam consumption and lower cooling water requirement.
- Advanced reclaiming technology – new processes for low temperature reclaiming have dramatically reduced solvent losses.
- Heat integration with the power plant – three potential strategies for power plant integration, flue gas reboiler, vacuum condensate heating and supplemental duct firing in natural gas combined cycle power plants.

To date Fluor has 24 plant/licenses for Econamine FG worldwide and another 10 on order. These plants process flue gases with CO_2 concentrations range from 3% to 20% v/v and O_2 concentrations from 1 to 15% v/v. Econamine FG is the only process that has commercially demonstrated CO_2 recovery from a gas turbine exhaust. The plant is located in Bellingham, MA, with a capacity of 330 t/d of CO_2. The plant produces food grade CO_2 from a flue gas stream with 3.5% CO_2 and 13-14% O_2, v/v.

3.2.3 ABB Lummus Crest

The ABB solvent process was developed by Kerr-McGee Chemical Corp. and ABB Lummus Crest Inc. for CO_2 recovery from coal-derived flue gas. The process uses an aqueous solvent containing 15-20 wt% MEA and a proprietary inhibitor that allows for oxygen in the feed gas. The process was used in a 200 tonne/day food-grade liquid CO_2 plant in Oklahoma (Barchas, 1992). The system contains a caustic-based desulfurization unit to reduce SO_2 levels from over 100 ppmv to less than 10 ppmv. Approximately 90% of the inlet CO_2 is recovered. Although this process has been in use commercially, we are not aware of any other installations being built after the earlier plant in Oklahoma.

3.2.4 HTC Purenergy

HTC Purenergy (HTC) is a Canadian company, backed by extensive R&D work by the University of Regina and the International Test Center. The IP includes unique customized solvents, proprietary modelling/simulation and process engineering.

HTC offers the world's first pre-engineered modularly constructed CO_2 capture unit that can be retrofitted to existing or new-build coal and gas fired power plants. The system is said to be capable of capturing up to 3000 tonnes per day of CO_2. Presently it has no commercial or demonstration installations. However, jointly with Doosan Babcock, they have submitted a proposal on a UK Government sponsored initiative to install and demonstrate a 300 MW Carbon and Capture and Storage project integrated into a coal-fired power plant.

In a September 4, 2008 news release, HTC Purenergy and Doosan Babcock of the UK signed a Global Technology Licensing Agreement which includes the right to utilize products and technologies developed by HTC and the University of Regina/International Test Center. In conjunction with the Licensing Agreement, Doosan Babcock and its parent Doosan Heavy Industries will subscribe to a Private Placement for an approximate 15% equity share ownership in HTC with an investment of CDN $10 million.

3.2.5 Cansolv

Cansolv is a Canadian company founded in 1997 (spin-off of the Union Carbide Canada SO_2 program). The company's main business is its commercially proven SO_x removal technology. It has commissioned 7 - SO_2 plants between 2002 and 2007; 2 - SO_2 scrubbers are now under construction and another 4 in design phrase.

Using its SO_2 Scrubbing platform, for the period from 2002 to 2007, it focused its R&D effort on developing high performance solvents for NO_x, Hg and CO_2 absorption (Rick Birnbaum, 2007). The idea is to combine SO_2 and CO_2 removal in one integrated process (integrate SO_2 and CO_2 absorbers into one vessel and SO_2 and CO_2 regeneration into the process configuration). Cansolv has a multi-pollutants pilot plant which was commissioned in November 2004. It is a useful tool to prove technology prior to large scale application. We are not aware of any pilot results in the literature. Currently there is no commercial or demonstration installation. However, one large scale demonstration plant in coal-fired service is being planned.

3.2.6 <u>PowerSpan</u>

PowerSpan Corp. is a clean energy technology company based in Portsmouth, New Hampshire, USA and is engaged in the development and commercialization of proprietary multi-pollutant control technology for the electric power industry. It has patented the Electro-Catalytic Oxidation or ECO technology, which provides high removal of four major pollutants - SO_x, NO_x, mercury and fine particulate matter, from coal-based power plants. The process produces as a by product ammonium sulfate fertilizer, which is sold in the open market. It has no liquid discharge and no flue gas desulfurization landfill waste.

PowerSpan is now developing an ECO_2 technology as an add-on feature to ECO (Chris McLarnon, 2008). ECO_2 uses aqueous ammonia as the absorbent for the removal of CO_2. Ammonia has a lower heat of reaction and consequently results in reduced energy requirements.

The overall reaction is as follows:

$$CO_2\,(g) + (NH_4)_2CO_3\,(aq) + H_2O\,(l) \leftrightarrow 2\,NH_4HCO_3\,(aq)$$

The ammonia bicarbonate is converted back to ammonia carbonate releasing the CO_2 in the regenerator. The ECO_2 technology was developed and patented by the US Department of Energy, from which PowerSpan has an exclusive license. The ECO_2 process has undergone extensive laboratory testing. Managing the CO_2 carrying capacity in ammonia and ammonia slip (both at the absorber and regenerator) are keys to process success. It also has a large scale pilot (~ 20 tonne/day CO_2 or 1 MW equivalent of a slip stream from a 50 MW commercial unit) at First Energy's R.E. Burger Plant in Shadyside, Ohio, which integrates with an ECO process. The objectives of the pilot are:

- Evaluate process performance and economics for scale–up
- Demonstrate ammonia vapor control
- Verify process performance and control under varying conditions

Pilot results are due out later this year. Under the ECO_2 commercial demonstration plan, the next stage is a 120-MW CO_2 capture demonstration at Basin Electric's Antelope Valley Station near Beulah, North Dakota, USA. It is currently performing feasibility study. The plant is designed to capture 90% of the incoming CO_2 (~ 1 million tons/year) and is expected to be operational in 2011.

3.2.7 Alstom Chilled Ammonia Process

The Chilled Ammonia Process (CAP) is drawing a lot of attention lately, because it uses a solvent other than amine and also it is supported by Alstom and EPRI with a well funded R&D program. The CAP has been tested through small and large bench scale testing at SRI International (worked co-funded by Alstom, EPRI and Statoil). Field scale pilot testing is now being carried out at a 5 MW_t unit at We Energies (work co-funded by Alstom and EPRI). The next stage would be a commercial demonstration at AEP Mountaineer plant, WV. In April 2008, TransAlta announced the signing of an agreement with Alstom to test the chilled ammonia technology at one of TransAlta's coal-fired power generation stations west of Edmonton and reduce current CO_2 emissions by one million tonnes a year.

Aqueous ammonia reacts with CO_2 in three competing reactions;

At 77^{o}F and 1 atm,

NH_3 (aq) + H_2O (l) + CO_2 (g) <-> NH_4HCO_3 (aq) ΔH = -622 BTU/lb CO_2 {1}

2 NH_3 (aq) + H_2O (l) + CO_2 (g) <-> $(NH_4)_2CO_3$ (aq) ΔH = -986 BTU/lb CO_2 {2}

$(NH_4)_2CO_3$ (aq) + H_2O (l) + CO_2 (g) <-> 2 NH_4HCO_3 (aq) ΔH = -262 BTU/lb CO_2 {3}

All these reactions are exothermic in the direction of CO_2 absorption. Of these three reactions, reaction {3} requires the least amount of energy for regeneration, 262 BTU/lb CO_2 (this is much lower than the 703 BTU/lb CO_2 for MEA). So if the reaction is limited to reaction {3}, the cycling between ammonium carbonate (AC) and aqueous ammonium bicarbonate (ABC), this could result in significant energy savings in absorption and desorption. This can be accomplished by operating at temperatures below 60^{o}F; above 60^{o}F, ABC and AC degrade in aqueous ammonia.

Low temperature operation is challenging because the solubility of ABC is low at low temperature, leading to solids precipitation. Alstom chose to utilize a high concentration AC solution to take advantage of increased CO_2 capacities and lower solution circulation rates. To address ABC precipitation in the absorber, Alstom selected an absorber design that is not affected by solids formation and instead circulates a slurry of aqueous AC, aqueous ABC and solid ABC. Ammonia slip may still be a problem due to the high AC concentration utilized, but the low temperature operation and circulation of solids may help to mitigate this issue.

The system uses a CO_2 absorber similar to SO_2 absorbers and is designed to operate with slurry. The cooled flue gas flows upwards in counter current to the slurry containing a mix of dissolved and suspended ammonium carbonate and ammonium bicarbonate. More than 90% of the CO_2 from the flue gas is captured in the absorber. The remaining low concentration of ammonia in the clean flue gas is captured by cold-water wash and returned to the absorber. The clean flue gas which now contains mainly nitrogen, excess oxygen and low concentration of CO_2, flows to the stack.

A process flow diagram for CAP is shown in Figure 3.3.

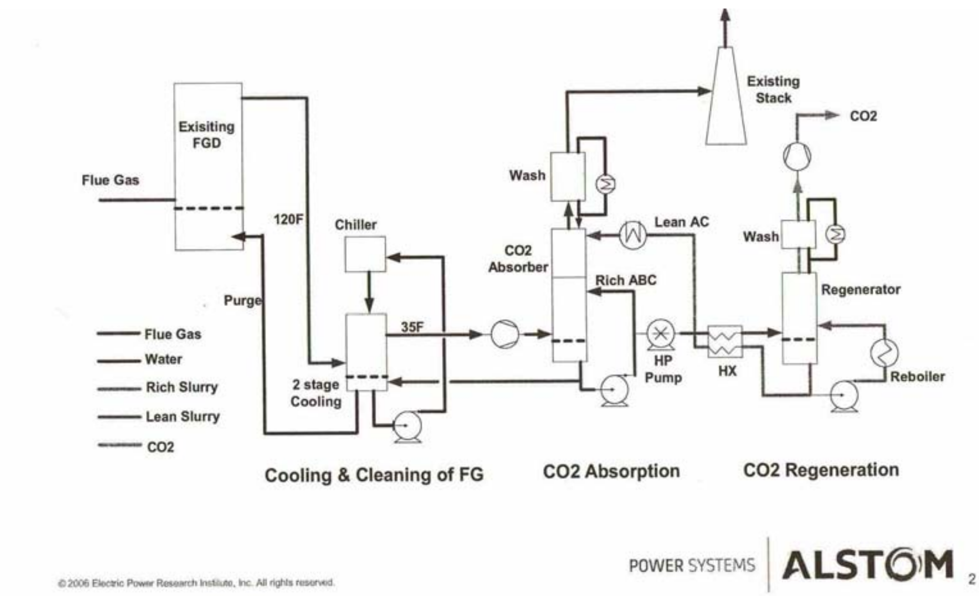

Figure 3.3: Schematic of the Chilled Ammonia Process (CAP)

The advantages of CAP are;

- Energy efficient capture of CO_2
- High capacity for CO_2 per unit of solution
- High pressure regeneration
- Low heat of reaction
- Low cost reagent
- No degradation during absorption-regeneration
- Tolerance to oxygen and contaminants in gas

The following Table 3.1 is a comparison of CAP and MEA:

Table 3.1. Comparison between CAP and MEA.

Factors	MEA	CAP	Comments
Makeup absorbent	MEA	NH_3	
Makeup cost $/tonne	800-1200	100-200	
CO_2 loading kg/kg solution	0.04 – 0.06	0.1 – 0.2	A slurry of 25 to 67 wt% solids
CO_2 capture efficiency %	90%	90%	
Absorption temperature C	40 – 60°C	1.5 -15°C	Requires significant refrigeration load which may not offset the reduced steam load
Heat of reaction kJ/mole CO_2	84.4	25.6	
Regeneration temperature C	100 – 120°C	95 – 125°C	
Regeneration pressure atm.	1 -2	20	High pressure pumping
Makeup kg/tonne CO_2	1.6	0.2	

Major Components

Induced draft fan		Same	
Pumping for CO_2 system		More energy	Slurry pumps
Chiller		more energy	Required for CAP
Absorber	Packed	FGD type	FGD type absorber has not been proven for CAP application
Regeneration		Less energy	Reduced steam requirement
CO_2 compressor		Less energy	Reduced compression as the CO_2 product stream can reach 20 atm
Equivalent parasitic load %	30	10	Depends on refrigeration and regeneration loads

There is significant trade-off between CO_2 carrying capacity and ammonia slip. Recovering ammonia from waste stream is difficult and expensive. CAP has its critics also. Paul Mathias et al. (2008) argue that based on fundamental thermodynamic analysis:

- Heat of solution for CAP is similar to MEA – and much higher than claimed. Therefore the heat of regeneration is similar to MEA.
- Ammonia slip in the absorber is high, about 1000 to 3000 ppm. Ammonia slip can only be mitigated by lower CO_2 removal efficiency.

3.3 STATUS OF CURRENT STATE OF CO_2 CAPTURE FROM COMBUSTION FLUE GASES

The front runners are Fluor Econamine FG+ and MHI KS-1 process. Their experience and performance are similar. If a plant to capture CO_2 from combustion flue gases is to be constructed in the next 5 years, the process options are probably limited to one of these two processes. However, it should be noted that Fluor is the only company with experience on capturing CO_2 from the low CO_2, high O_2 concentration flue gas from gas turbine. The other processes mentioned above are either at small scale commercial demonstration or pilot stage. Therefore, in our opinion, these technologies would not be deployed with plant construction until ten years from now.

In terms of plant scale, most of the CO_2 plants constructed in the last few years are in the 300 to 500 tonnes per day CO_2 range. This is probably due to application requirement – urea production. In our opinion, a single train is probably 3000 tonnes per day (1 million tonnes CO_2 per year) with a single absorber and can easily be extended to 6000 tonnes per day (2 million tonnes per year) with two absorbers and one regenerator.

3.4 ECONOMICS OF CO_2 CAPTURE

The basis of the cost evaluation is a stand-alone CO_2 capture plant producing 2 million tonnes per year of CO_2 (5,500 tonne/d) with the CO_2 compressed to a pressure of 14.4 MPa (excluding pipeline cost). CO_2 recovery efficiency is assumed at 90%. The capture plant would generate all its steam requirements on site; hence there is no heat integration with other plants. Electricity is available to the site from the power grid.

For operating costs, natural gas and electricity are priced at $7.00/MMBTU and $80/MWh respectively; and cooling water is assumed available at reasonable price to the site. To calculate capital charges, a real rate of return of 10% and plant life of 30 years are used. A three year construction period is assumed, with the following capital expenditure profile, 25%, 35% and 40%.

The ARC Integrated Economic Model (IEM) is used to develop cost estimates for CO_2 capture using the MHI KS-1 solvent. A steam consumption of 1.3 t/t of CO_2 is assumed. The first case is recovering CO_2 from a 13% CO_2 flue gas from the main stack.

The capital cost estimate for this capture plant is Canadian $479.8 million. CO_2 production cost is $89.8/tonne (see Tables 3.2 and 3.3). All costs are in 2nd quarter 2008 Canadian dollars.

It should be noted that until recently we were in an escalating cost environment. The Chemical Engineering Plant Cost Index has increased 48.6 % from 2003 to 2008 (ChE Plant Cost Index grew from 401.8 to 597.1), a rate increase of 8.2% per year for this period. This is in part due to escalating commodity prices like energy and iron and steel. In addition, Alberta is particularly hard hit by a shortage of skilled labor. Therefore, the cost estimate is prepared in a cost environment that is escalating and a tight labor market and should be treated accordingly.

Table 3.2. Capital cost estimate of a MHI KS-1 CO_2 capture plant from a 13% CO_2 waste gas stream.

Flue Gas Desulfurization	\$48.5 MM
CO_2 Recovery	\$237.9 MM
Compression	\$54.8 MM
Utilities - Cooling water system \$36.3 MM - Other utilities \$58.6 MM	\$94.9 MM
Contingency	\$43.6 MM
Total	\$479.8 MM

Table 3.3. Estimate of CO_2 cost using the MHI KS-1 solvent process.

2008 Canadian dollars		**Cost \$/tonne CO_2**
Capital Charges		28.8
Fixed Costs		16.4
Variable Costs		44.6
- electricity	8.45	
- natural gas	30.2	
- others	6.0	
Total		89.8

The cash cost of CO_2 production is \$61.0/tonne. Energy costs (electricity and natural gas) takes up over 63% of the cash cost. A 20% reduction in energy prices (natural gas price from \$7/MMBTU to \$5.6/MMBTU and electricity price from \$80/MWh to \$64/MWh) reduces the CO_2 cost by \$7.7/tonne (about 8.6% of the CO_2 production cost). So the CO_2 capture process is highly energy intensive.

Reducing capital costs by 20% decreases the capital charges by \$5.7/tonne (about 6.3% of the CO_2 production). Therefore the CO_2 capture process is also capital intensive. Reducing the discount rate from 10% to 8% reduces the cost by about \$4.7/tonne. Perhaps for this type of project, utility type of financing may be more appropriate.

We also ran the IEM model for three other waste gas compositions, 3.5% CO_2, 9.2% CO_2 and 18.6% CO_2. The results are tabulated in Table 3.4.

Table 3.4. Estimate of CO_2 cost for three CO_2 concentrations of 3.5%, 9.2% and 18.6%

2008 Canadian dollars $/tonne CO_2	3.5% CO_2*	9.2% CO_2	18.6% CO_2
Capital Costs $ MM	1234	629	396.8
Capital Charges	71.2	36.3	22.9
Fixed Costs	43.8	20.5	13.1
Variable Costs			
- electricity	23.2	10.5	6.6
- natural gas	26.5	28.4	28.8
- others	6.9	5.9	4.6
Total	171.6	101.6	76.0

* the waste gas stream does not contain sulphur, therefore desulphurization is not required

Figure 3.4 shows the cost of capturing CO_2 for a range of CO_2 concentrations using a chemical absorption process. The cost of capturing CO_2 decreases as the CO_2 concentration in the flue gas increases.

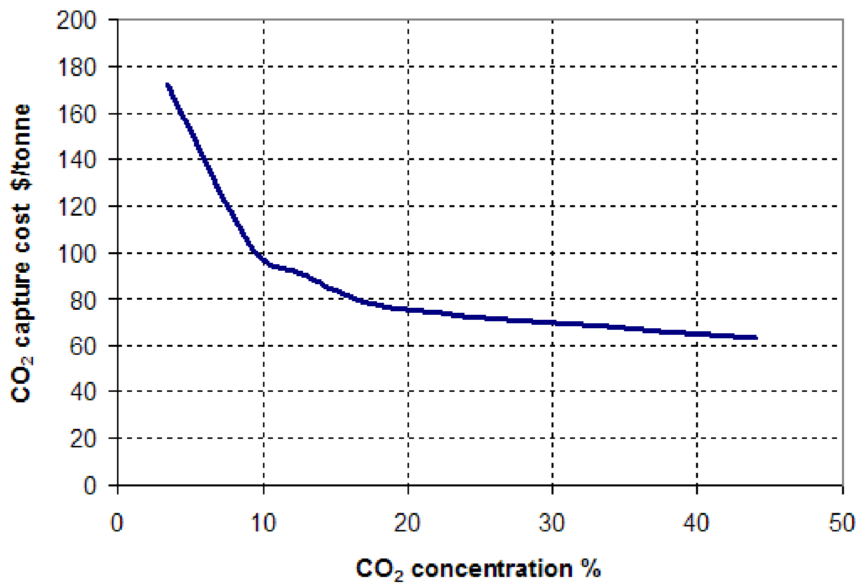

Figure 3.4. CO_2 capture cost versus CO_2 concentration in the flue gas.

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CHAPTER 4

CO_2 CAPTURE FROM GASIFICATION PROCESS

4.1 OPTI-NEXEN GASIFICATION OF ASPHALTENE AT LONG LAKE

As part of this Study, we have studied the operations of Opti-Nexen at Long Lake, Alberta, as it is the only project currently producing hydrogen and steam from the gasification of asphaltene in the Fort McMurray area. We have built a base model of the main processes involved in the aforementioned operations, namely: upgrading, gasification, and co-generation. This first principles model is based on our current understanding of the above processes. We have reviewed several published sources that provide insights into the operations and design of the Long Lake Project. These sources include, but are not limited to:

- Opti-Nexen's application to the AEUB, sections A to C and appendixes.
- Papers and presentations by Opti-Nexen at technical/other conferences between 2000 and 2007.
- U.S. and Canadian patents of the Orcrude™ upgrading process and other supporting upgrading processes (e.g., solvent deasphalting)

This Chapter summarizes the results of the modelling and discusses the options of capturing CO_2 from the gasification operation.

4.1.1 <u>Bitumen upgrading</u>

Opti's Orcrude™ process is described in detail in U.S. patent 6,702,936 B2 (2004). It consists of 5 process units, as shown in the simplified flowsheet in Figure 4.1. The diluted bitumen extracted via SAGD is fed to an atmospheric distillation tower, producing an overhead gas stream, distillate fractions, and atmospheric bitumen residue. The gas stream containing propane, butane, and moderate amounts of sulphur is fed to a gas processing unit (not shown). The distillate stream is sent to a hydrocracking unit for further processing while the column bottoms are fed to a vacuum distillation unit. Further recovery of lighter fractions is accomplished in the vacuum-operated tower, with additional production of overhead gas. The lighter fractions are sent to the hydrocracker and the overhead gas to a gas processing plant.

The residue from the vacuum tower is routed to a solvent deasphalting unit, where it is separated into deasphalted oil (DAO) and asphaltene by-product. The asphaltene stream contains high-carbon content materials and a high concentration of metals. The DAO is essentially metal-free and is thermally cracked in a cracker downstream of the deasphalter. Thus, heavy, high boiling point range, long-chain hydrocarbons are broken into lighter fractions. The thermally cracked DAO is then recycled to the distillation unit where recovery of the produced light fractions is accomplished and the process is repeated. The asphaltene stream is used as fuel for the gasification process.

The recovered light sour fractions from the distillation columns are treated with hydrogen in the hydrocracker, producing sweet synthetic crude oil and acid gas. The former is the final product of the process while the latter is processed in a downstream gas separation plant.

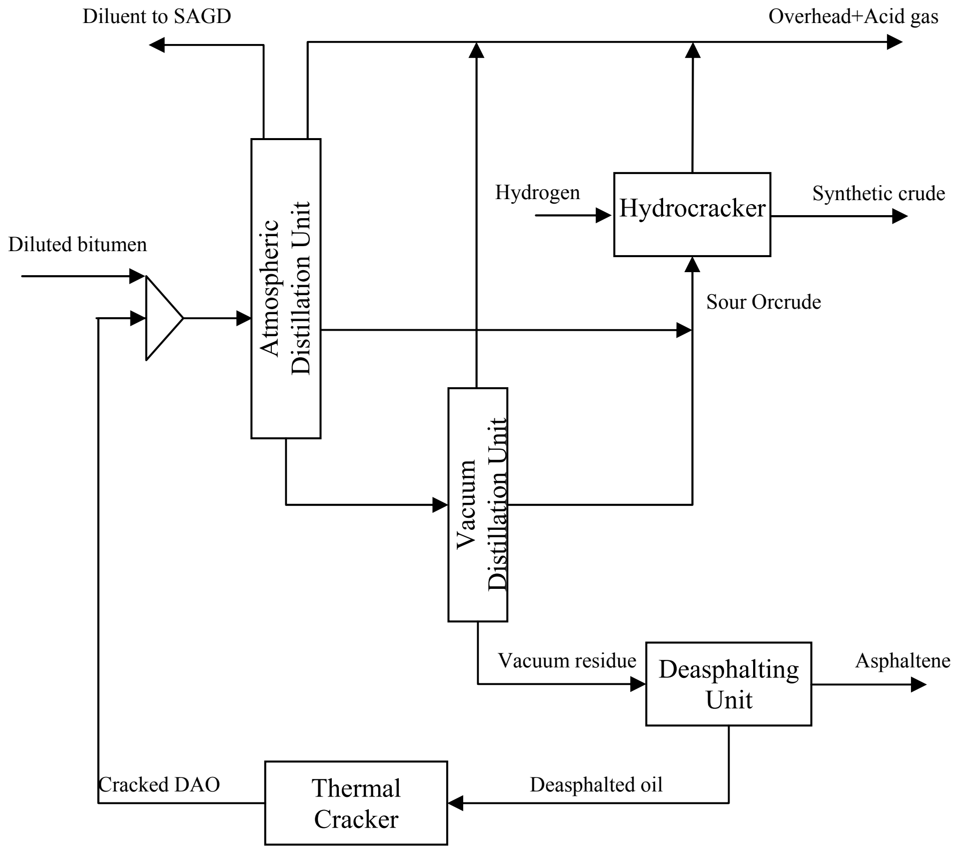

Figure 4.1. OrCrude™ upgrading process

The mass and energy balances of the above process were developed on the basis of the data provided by Opti-Nexen for the 11,200 m^3/d SAGD/ 22,400 m^3/d Upgrader + Co-generation case detailed on OPTI Canada (2002). The resulting energy demands of the upgrading process are shown in Table 4.1, along with their equivalents for the three available fuels reported by Opti-Nexen.

The total calculated energy demands amount to 46.2 TJ/d. The energy demands according to Opti-Nexen are 50.2 TJ/d. The difference is likely due to energy-consuming auxiliary operations not reported in the application.

It is clear from Table 4.1 that refinery gas produced internally is insufficient to supply the energy demands of the upgrading process. Hence, in our current analysis, the balance of these demands is assumed to be met by syngas, which is an abundant fuel. In all instances, however, we have considered a case in which the energy demands are met by natural gas alone, for comparison purposes.

Table 4.2 shows the estimated CO_2 emissions from the upgrading process, using natural gas (reference) or refinery gas+syngas (actual). The expected CO_2 concentration from different sources is also shown, as a function of excess air. By default, this excess air is assumed to be 100%.

The total CO_2 emissions for the upgrading process are 3,761 tonne/d or 0.035 tonne/bbl SCO. Of these, 1,110 tonne/d are from refinery gas combustion and the balance from syngas. The CO_2 concentration (mole) of the former stream is estimated at 5.88% while the latter is 14.28%, for 100% excess air. The theoretical values for stoichiometric combustion (i.e., no excess air) are 10.05% and 22.90%, respectively, with identical net CO_2 volumes.

Table 4.1. OrCrude™ upgrading process – Energy demands

	Energy demands	Unitary demands	Natural gas	Refinery gas	Syngas
Proc. Unit	GJ/d	GJ/bbl SCO	Nm^3/d	Nm^3/d	Nm^3/d
ATM Distillation	25,438	0.24	683,818	655,619	2,312,548
VAC Distillation	2,681	0.02	72,063	69,092	243,705
Hydrocracking	14,766	0.14	396,924	380,556	1,342,326
Deasphalting	3,282	0.03	88,232	84,593	298,384
Thermal Cracking	55	0.001	1,479	1,418	5,001
Total Upgrading	46,222	0.43	1,250,693	1,199,589	4,210,648
Available fuel	-	-	unlimited	560,934	18,420,376

In comparison, meeting upgrading demands with natural gas yields CO_2 emissions in the order of 2,226 tonne/d or 0.021 tonne/bbl SCO with a mole fraction of 5.56% to 9.53% for 100% and stoichiometric air, respectively.

Table 4.2. OrCrude™ upgrading process – CO_2 emissions (tonne/d)

Process Unit	Natural gas	Refinery gas	Syngas	Refinery gas+syngas
ATM Distillation	1,225	1,110	398	1,508
VAC Distillation	129	-	291	291
Hydrocracking	711	-	1,601	1,601
Deasphalting	158	-	356	356
Thermal Cracking	3	-	6	6
Total Upgrading	2,226	1,110	2,651	3,761
CO_2 in flue gas (mole %)	5.56%	5.88%	14.28%	100% excess air
	9.53%	10.05%	22.90%	0% excess air

4.1.2 <u>Gasification</u>

The gasification process of the Long Lake project is shown in schematic form in Figure 4.2. The asphaltene from the upgrading section is gasified with oxygen and steam in a Shell gasifier. Steam (sent to the SAGD section) is generated in the gas cooling section of the gasification plant. The raw syngas is treated in a sulphur removal plant, yielding sweet syngas and an acid gas stream consisting of H_2S and some CO_2. The sweet syngas contains enough hydrogen to meet the demands of the upgrading process, so a steam shift section is unnecessary. Instead, the syngas is processed in a PSA (Pressure Swing Adsorption) unit where some of the hydrogen in the syngas is recovered as a high-purity gas. The PSA offgas is available as fuel for steam and electricity production in a co-generation plant.

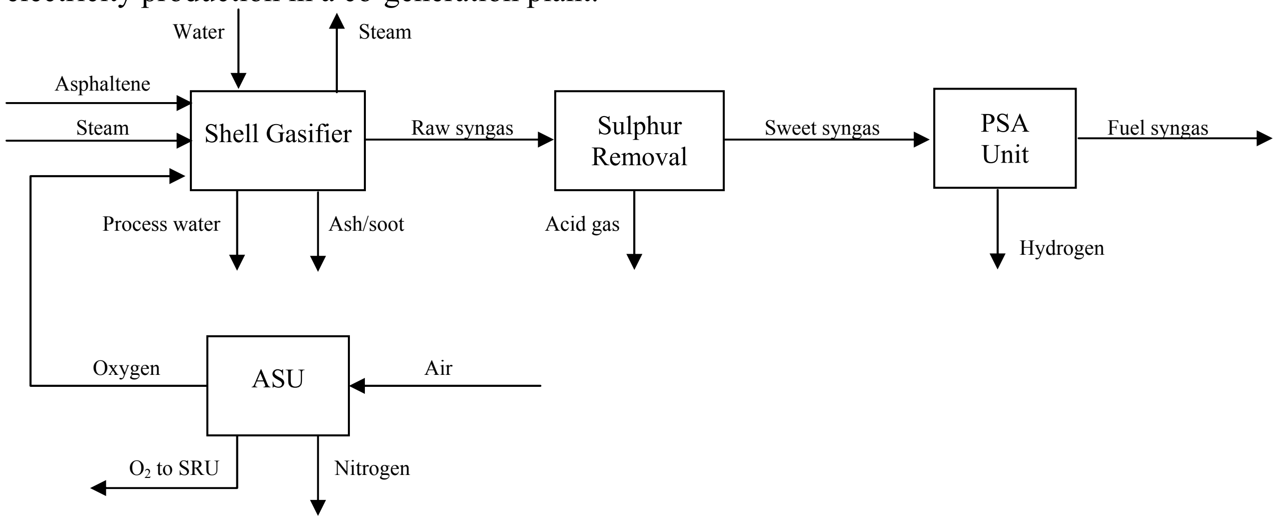

Figure 4.2. Opti-Nexen Gasification process

A complete mass balance of the gasification process has been developed. The outcome of this exercise is the characterization of the above streams, including their composition. The stream in the process that we are mostly interested in is the fuel syngas (or PSA offgas), which affects the composition of the flue gas generated in the co-generation plant. Table 4.3 is a summary of the syngas compositions derived from our mass balances.

Table 4.3. Syngas compositions for the gasification process (dry, mole %)

Stream	Raw syngas	Sweet syngas	Fuel syngas
H_2	38.6	39.8	13.8
CO	51.4	52.9	75.7
CO_2	7.1	5.7	8.1
H_2S	1.6	0.5	0.7
Ar	1.0	1.0	1.5
CH_4	0.2	0.2	0.3

The above fuel syngas has a calculated heating value of 10.73 MJ/m^3 (HHV) and 9.67 MJ/m^3 (LHV). This gas is used as fuel in the co-generation plant for steam and power production.

4.1.3 Co-generation

As mentioned earlier, the PSA offgas from the gasification section is used as fuel in a cogeneration plant, shown in schematic form in Figure 4.3. The available fuel gas is split into 3 streams that are used for different purpose. The first stream is used as fuel for the upgrading process, as described earlier. The second stream is fed to gas turbines for power generation. The remaining syngas is available for steam generation in a HRSG (Heat Recovery Steam Generator), downstream of the turbines.

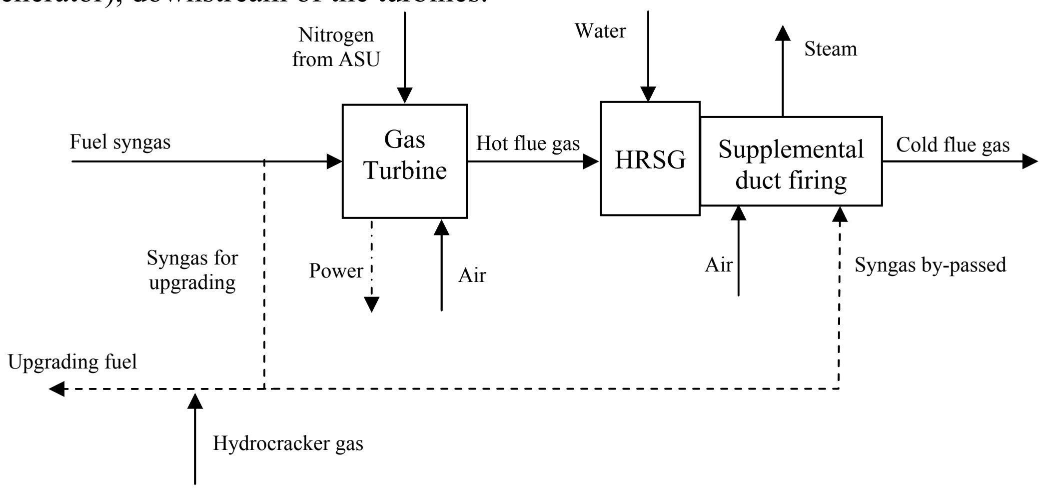

Figure 4.3. Opti-Nexen Co-generation plant

The amount of fuel syngas for upgrading is assumed to be fixed, whereas the syngas consumption in the turbine is a function of the desired power output and the turbine heat rate. In this Study, the above values are taken from OPTI Canada (2002) and the material and energy balances are developed on the basis of 370 MW and a heat rate of 9,330 kJ/kWh, as specified by Opti-Nexen. Additionally, we have assumed that all of the nitrogen from the air separation unit is injected in the turbine for NO_x control and flow augmentation, which is a common practice with syngas-fired turbines.

Table 4.4. Stream compositions for the co-generation plant (dry, mole %)

Stream	Upgrading fuel	Fuel syngas	Hot flue gas	Cold flue gas
H_2	32.4	13.8	0.0	0.0
CO	57.0	75.7	0.0	0.0
CO_2	7.9	8.1	11.9	13.0
H_2S	0.5	0.7	0.0	0.0
Ar	1.1	1.5	0.2	0.2
CH_4	0.4	0.3	0.0	0.0
SO_2	0.0	0.0	0.1	0.1
N_2	0.7	0.0	81.2	79.4
O_2	0.0	0.0	6.6	7.2

The hot flue gas exiting the gas turbine is used to produce steam in the HRSG. The additional syngas is fired in the HRSG for increased steam production. We assumed the steam conditions to be 8,000 kPa and 80% dryness, as specified by Opti-Nexen. The boiler efficiency is assumed to be 80% when using syngas as a fuel, while the excess air is 100% by default.

The flue gas composition is determined on the basis of the mass and energy balances developed for the co-generation plant. Table 4.4 shows the calculated compositions of the main process streams.

Our analysis revealed that the produced syngas is sufficient to satisfy the steam and power demands of the project. Our model determines the amount of syngas fuel needed to produce power and adjusts the amount of syngas sent to the HRSG accordingly. The breakdown of syngas fuel in the co-generation plant is shown graphically in Figure 4.4.

According to Opti-Nexen, the steam demands for the 11,200 m^3/d SAGD/22,400 m^3/d Upgrader + Cogeneration case (OPTI Canada, 2002) are 26,880 tonne/d at a SOR (steam-to-oil ratio) of 2.5. Their specified steam production from the co-generation plant and OSTG (Once-Through Steam Generator) boilers is 19,897 tonne/d. The balance steam is produced in the gasification section (syngas cooling). On the basis of our mass and energy balances, the co-generation plant can produce a maximum of 22,560 tonnes of steam per day. Thus, up to 2,663 tonne/d of excess steam can be produced using the available syngas in the co-generation plant, along with 370 MW of electricity.

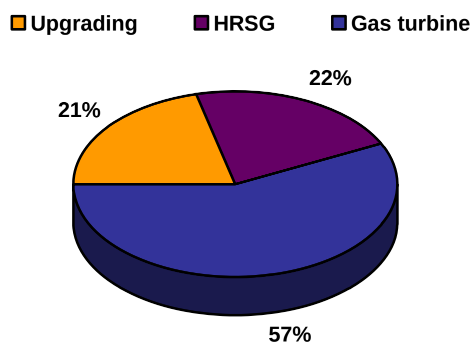

Figure 4.4. Syngas disposition in Co-generation plant

Finally, the calculated CO_2 emissions of the co-generation process are estimated at 17,813 tonne/d, with a mole fraction of 13% (100% excess air). If no nitrogen is injected in the turbine, the mole fraction rises to 17.5% (100% excess air). Assuming stoichiometric (0% excess) air, the CO_2 concentration in the flue gas is 27.4% (no nitrogen injection) and 17.9% (nitrogen injection). In all instances, the minimum steam demands (19,897 tonne/d) are met.

4.2 CO_2 CAPTURE OPTIONS

Mitigating emissions from an integrated upgrading-gasification process such as Opti-Nexen's Long Lake project via CCS involves modifications to the process. This is commonly referred to as a CO_2 retrofit. Retrofitting plants that were not designed with provisions for future implementation of CCS generally involve the following:

- Addition of a CO shift section
- Addition of a CO_2 removal unit
- Addition of CO_2 drying and compression facilities
- Modification of gas turbine to operate on hydrogen instead of syngas fuel
- Addition of air compression capacity for ASU (if necessary)
- Capacity increases of plant utilities

To effect the above additions and modifications, physical space, capital, and additional energy production are required. Thus, the technoeconomics of a retrofitted process will differ from those of the original and are a function of the extent of CO_2 captured and the specific technologies chosen by the designers.

In this section, we describe a proposed CO_2 retrofit of the gasification section of the Long Lake project and outline its anticipated consequences on operations.

4.2.1 Addition of CO shift

An indispensable part of a CO_2 capture system in gasification applications is the CO shift section. The syngas reacts reversibly with steam over a catalyst to convert the CO in the syngas to CO_2. This step increases the CO_2 concentration and generates additional hydrogen according to the reaction:

$$CO + H_2O \leftrightarrow H_2 + CO_2$$

The CO shift can take place at various points downstream of the gasifier. The current configuration at Long Lake consists of an amine-based sulphur removal unit followed by a PSA unit, as shown in Figure 4.2. In principle, the CO shift unit could be placed upstream or downstream of the sulphur unit, or even downstream of the PSA unit. The former configuration is known as a "sour CO shift" whereas the latter is commonly referred to as a "sweet CO shift", due to the presence and absence of H_2S in the syngas feed to the shift unit, respectively.

In the case of Opti-Nexen, our belief is that a sweet CO shift is preferred as its implementation may be less complicated than a sour shift. Our analysis indicates that the CO shift reaction increases the total gas input to the sulphur removal plant by 50%. Unless the original sulphur removal plant was designed to accommodate an increased flow of this magnitude, additional absorption and solvent regeneration trains will be required. Further, the acid gas removed must have an H_2S concentration that is acceptable for the sulphur recovery (i.e., Claus) unit. Thus, additional equipment will likely be required to increase the H_2S concentration of the acid gas feed, which would further increase the costs and complexity of the retrofit.

The above issues are associated with selective H_2S removal. In a CO_2 retrofit, an additional unit would be required for CO_2 capture post-sulphur removal. Although in certain circumstances it may be possible to integrate the existing sulphur removal equipment with the new H_2S and CO_2 removal units, this is not likely the case with Long Lake. Removing large volumes of concentrated CO_2 and H_2S into separate streams in a single plant favours the use of a physical solvent (e.g., Selexol, Rectisol, etc.) whereas the original sulphur removal plant is a chemical solvent (amine-based) plant.

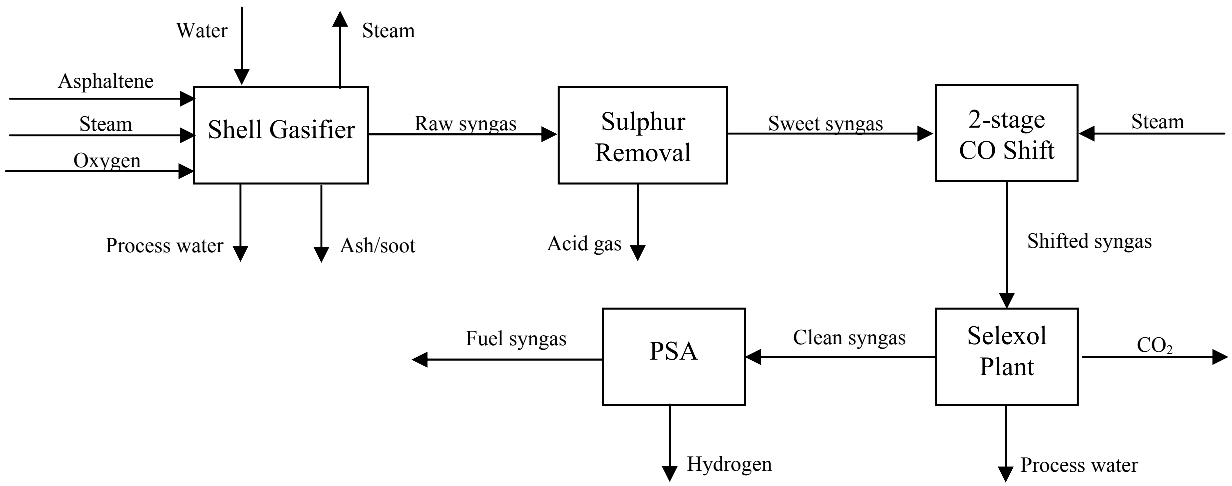

Figure 4.5. Opti-Nexen gasification process with sweet CO shift

In contrast, a sweet CO shift retrofit does not interfere with the design and operation of the existing sulphur removal plant as the syngas amounts and composition upstream of it remain unchanged. The flowsheet modifications required, namely the addition of a CO shift and a Selexol unit, are shown in Figure 4.5.

The main disadvantage of a sweet shift retrofit is the lost potential for economic steam saturation of syngas present in a sour shift scenario. When designing a greenfield plant with integrated CO_2 capture, a configuration involving a water quench gasifier and a sour shift is generally acknowledged as ideal. The water quench saturates the syngas, effectively providing most or all the required water necessary for the CO shift reaction. Since typical steam requirements for the shift reaction are in the order of 2.5 - 3 times the quantity of CO in the syngas, a water quench followed by a sour CO shift eliminates the need for injecting substantial amounts of expensive steam.

According to Higman (2007), sweet CO shift designs featuring a saturator-desaturator system can be used to reduce the steam demands to values as low as the stoichiometric amount. Although the saturator-desaturator equipment require an additional investment, the steam savings seem to offset the initial investment and thus, is our choice for the proposed CO_2 retrofit of the operations at Long Lake. A schematic of the concept is shown in Figure 4.6.

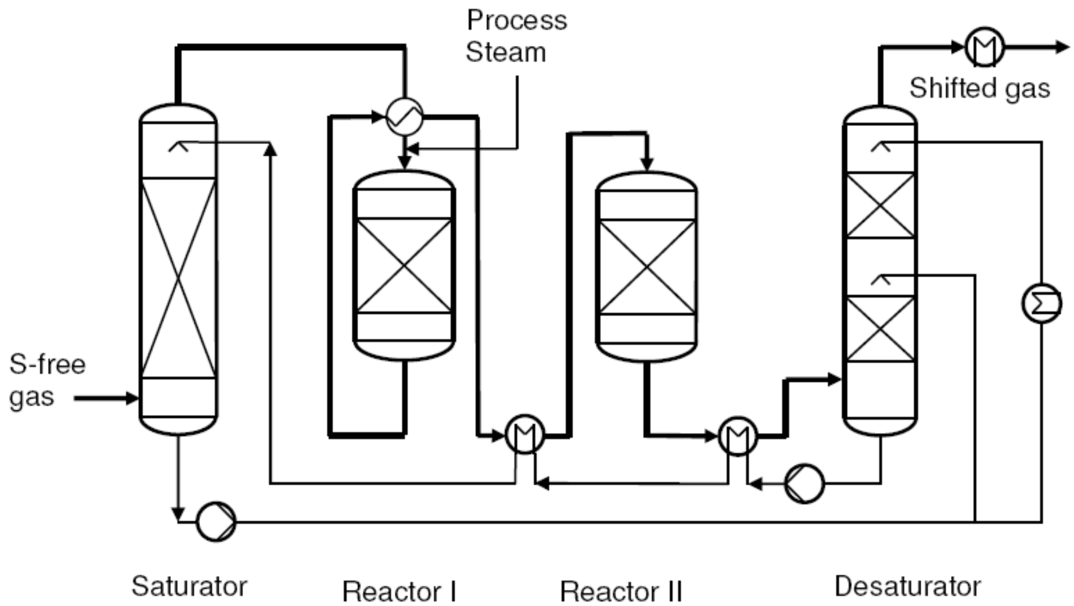

Figure 4.6. CO sweet shift with saturator-desaturator (Higman, 2007)

We propose that the shifted syngas be treated in a Selexol plant for bulk CO_2 removal. In this study, we have assumed a CO_2 capture efficiency of 90%, a common value in the literature, and desirable if the goal of the retrofit is to minimize CO_2 emissions.

The syngas exiting the Selexol plant contains mostly H_2 and minimal amounts of contaminants. Hence, the CO_2 retrofit has an impact on the performance of the hydrogen purification unit, in this case, a PSA (Pressure Swing Adsorption). The net inflow to the PSA after CO_2 capture is smaller than the original design flow. Our calculations suggest that the mass of syngas entering the PSA is 3.1 times smaller than the unshifted syngas. The actual effect on the process is that the PSA unit would be oversized for the required purification level. Thus, the PSA after the retrofit has excess syngas capacity. Also, due to the increased H_2 concentration of the syngas, the H_2 recovery required to meet the H_2 demands of the upgrading process drops by roughly half. This may potentially reduce the energy requirements of the PSA unit.

Table 4.5 shows the estimated compositions for all syngas streams shown in Figure 4.5. The original (no CO shift) PSA offgas stream is also provided for comparison purposes.

Table 4.5. Syngas compositions for the gasification process with sweet CO shift (dry, mole %)

Stream	Raw syngas	Sweet syngas	Shifted syngas	Clean Syngas	Fuel syngas	Fuel syngas*
H_2	38.6	39.8	59.2	87.8	82.2	13.8
CO	51.4	52.9	3.6	4.8	7.0	75.7
CO_2	7.1	5.7	36.1	5.6	8.1	8.1
H_2S	1.6	0.5	0.3	0.5	0.7	0.7
Ar	1.0	1.0	0.7	1.1	1.6	1.5
CH_4	0.2	0.2	0.1	0.2	0.3	0.3

* No CO shift, current Long Lake process estimated stream

4.2.2 Integration issues

The CO_2 retrofit of the Opti-Nexen gasification process impacts the operations of the co-generation plant and poses certain issues related to fuel supply in the upgrading plant. Firstly, the mass and composition of the fuel gas supplied to the gas turbine in the co-generation plant changes drastically once the CO_2 retrofit is accomplished. Our analysis reveals that the available fuel syngas after CO_2 retrofit is roughly 40% of the available syngas in the original design. This is a direct result of the loss of CO in the fuel due to its removal as CO_2. The consequence is that the turbine will be underloaded, which will affect its output.

In the present application, however, the nitrogen from the oxygen separation plant can be used for flow augmentation. Additionally, the literature suggests that another strategy to partially alleviate the turbine underloading, is to reduce the extraction air from the turbine compressor (Higman, 2007). This air is often used as feed to the oxygen plant, to reduce compression load in the air separation unit (ASU). It is unknown at this point if the gas turbine compressor is integrated with the ASU at the Long Lake plant. If so, an eventual retrofit may demand additional compression equipment to make up for the lost extraction air in the ASU, which would drive costs up.

The second implication of the CO_2 retrofit in the gas turbine is related to burning a hydrogen-rich fuel instead of syngas. This would potentially require modifications to the turbine burners, which though feasible, incur an additional expense. Additionally, the hydrogen-rich fuel causes a rise in the design metal temperatures of the turbine blades. This, combined with the expected increase of water content in the flue gas, imposes compensatory measures such as lowering the firing temperature, which reduces the efficiency of the turbine. The tradeoff here is between decreased efficiency and increased turbine blade erosion/corrosion, both of which increase operational costs.

Additional impacts related to the changes in syngas composition and quantity is found in two areas: syngas supply for upgrading operations and for supplemental duct-firing in the co-gen plant boiler. In both cases, it is uncertain if the current equipment is capable of burning the new fuel syngas, which is over 80% hydrogen. Moreover, the reduced amount of syngas available after CO_2 capture and H_2 extraction is insufficient to fully sustain operations in the co-gen plant *and* the upgrading section. Consequently, after CO_2 retrofit, a certain quantity of replacement fuel, likely natural gas, will be required to supply the energy requirements of the upgrading process.

4.2.3 Performance after CO_2 retrofit

We have estimated the anticipated impact of implementing CO_2 capture on the operations of the Opti-Nexen process. As mentioned earlier, the addition of a sweet CO shift and a CO_2 capture unit results in a reduced mass of syngas fuel. Also, as Table 4.5 shows, the syngas composition changes from a predominantly CO fuel to a predominantly H_2 gas. Due to the above two facts, we propose that all the syngas be used as fuel in the co-generation plant and that the energy needs of the upgrading process be supplied by natural gas. The advantage of this approach is that no retrofit of boilers, burners, or furnaces is required for the upgrading section. This keeps the modifications required to a minimum, thus saving down time and money. Although this is likely the most straightforward approach in terms of expensive and time-consuming modifications to the process, a future detailed techno-economic study involving integrating the CO_2-free shifted syngas fuel to upgrading operations is recommended.

The performance of the co-generation plant is directly affected by the CO_2 retrofit. Figure 4.7 summarize the changes in stream flowrates before and after the CO_2 retrofit. Generally speaking, the bulk of the penalty for CO_2 capture is reflected in a reduction in power output due to the increased steam and power demands of the CO shift and Selexol units, respectively.

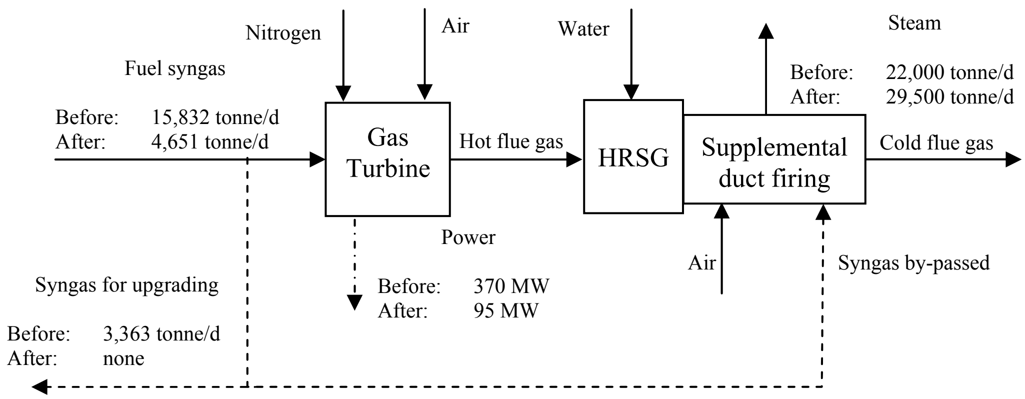

Figure 4.7. Changes in co-generation plant flowrates due to CO_2 retrofit

The net power output of the co-generation plant decreases to 95.3 MW from the original 370 MW after CO_2 retrofit, because the gas turbine is underloaded. The additional power demands of the CO_2 capture process and compression are estimated to be 188 MW. This figure is based on a CO_2 capture efficiency of 90%, with compression to 110 bar. The assumed energy requirements of the Selexol process are 245 kWh/tonne CO_2 captured (Ordorica-Garcia, 2006). This figure is on the high end of the spectrum and it is very likely that an optimal design for this study's application can further reduce the power requirements.

The power output is further affected by an increase in steam demands for the CO shift process. Our estimated demands after CO_2 retrofit amount to 29,500 tonne/d, versus 22,000 tonne/d originally. In this analysis, we use a steam to CO ratio of 1, assuming that the CO shift is a 2-stage saturator-desaturator system, as described by Higman (2007). If the steam: CO ratio increases, the plant's power output will further decrease, as the energy in the fuel will be used for steam, as opposed to power production. In an extreme case, additional boilers may be required, if the existing HRSG capacity is exceeded.

A CO_2 retrofit such as the one outlined in this study is limited by the ability of the co-gen plant to supply steam and power for SAGD operations, the CO shift, the Selexol plant, and the ancillary power demands. In practical terms, this means that to sustain existing operations without requiring make-up fuel, the sweet CO shift and Selexol units can only remove as much CO_2 as the available steam and power from the co-gen plant permits. Our analysis has identified that a 90% CO shift and CO_2 removal system is the recommended level that allows the co-gen plant to supply all the required steam and power. Increasing the CO shift above 90% would require additional steam and power generation, thus causing a deficiency in the power balance of the plant. Natural gas could be used for supplementary steam generation, subject to the capacity of the HRSG, or in separate boilers. This however, would increase costs and erode the advantage of using a co-generation plant.

The above recommendation is based on our first-principles modelling work. More accurate modelling and optimization of the co-gen plant under variable CO shift and CO_2 capture levels is required to determine the ultimate power and steam production potential of the co-gen plant integrated with the retrofitted gasification process. Of special concern is the assessment of the gas turbine performance with hydrogen-rich fuel, which only the manufacturer can provide and guarantee. Also, the required modifications to the heat recovery steam generator must be investigated and their techno-economics determined.

In terms of CO_2, the amount of carbon captured in the Selexol plant is 18,681 tonne/d. The purity of the CO_2 is estimated to be at least 92%. The purity varies depending on the extent to which H_2 and CO slip into the CO_2 stream. In this study, we chose relatively high values of 4% and 13%, based on previous modelling work (Ordorica-Garcia, 2003). An optimized Selexol plant may be able to yield CO_2 with purities in excess of 95%, but the energy penalty would likely rise.

The net CO_2 emissions of the co-generation plant are estimated to be 3,901 tonne/d. The CO_2 concentration in the flue gas is 3% on a dry basis, assuming 80% excess air. In contrast, the co-gen plant prior to the retrofit emitted 17,813 tonne/d, with a mole fraction of 13% (100% excess air). The excess air was varied in our analysis to regulate the firing temperature of the turbine, which is a function of the syngas composition.

In addition to the co-gen plant emissions, the emissions from natural gas use in upgrading amount to 2,226 tonne/d. The estimated CO_2 concentration in the upgrading gases is 7% at 50% excess air. Hence, the total emissions of the Long Lake plant after CO_2 retrofit are 6,127 tonne CO_2/d.

4.3 RETROFIT WITH FULL H_2 EXTRACTION AND NATURAL GAS SUPPLEMENTATION

An alternative configuration for the CO_2 retrofit involves maximizing the value of the syngas product by recovering all of the H_2 produced in the CO shift. If the hydrogen is sold, the revenues can be used to offset the added operati
onal costs of the CO_2 capture. Nevertheless, full hydrogen extraction results in a reduction in the turbine fuel gas flow as well as a sharp decrease in the fuel's calorific value. To compensate for the above, natural gas can be used as a supplemental fuel in the co-gen plant. Figure 4.8 depicts this concept and shows the calculated values of the main process streams.

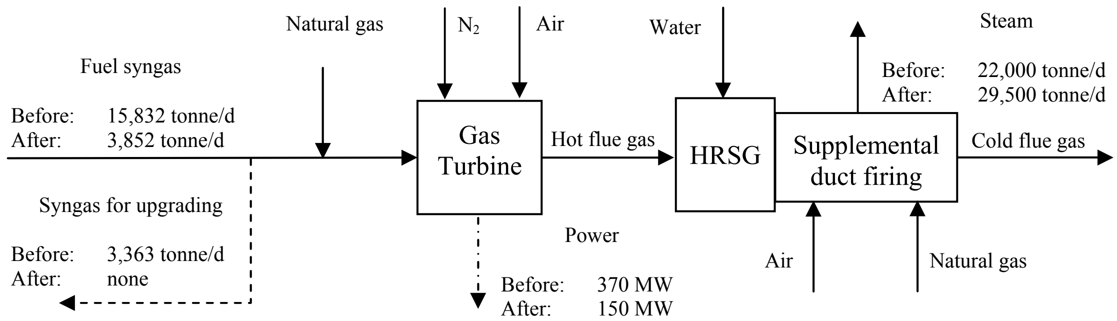

Figure 4.8. CO_2 retrofit with supplemental natural gas firing

Operations upstream of the co-gen plant are identical to the original CO_2 retrofit described earlier, with the exception of the H_2 recovery in the PSA. In the original design, the estimated recovery was 76%, whereas after CO_2 retrofit it dropped to 36%, due to the decreased syngas flow. Under full hydrogen extraction, 90% of the hydrogen in the syngas is removed. This operation yields 1,331 tonne/d of high-purity hydrogen. The H_2 demands of the upgrading process, as stated by Opti-Nexen, amount to 531 tonne/d, which yields 800 tonnes/d for sale.

The PSA offgas flowrate and composition change as a result of the full hydrogen extraction. Table 4.6 compares the syngas compositions and flowrates of the original process to the CO_2 retrofit with and without natural gas supplementation.

The estimated amount of supplemental natural gas required to fully load the gas turbine is 1.51 million m^3/d, or 56.2 TJ/d. This fuel is combined with the syngas from the PSA and fed to the turbine(s) in the co-generation plant, yielding a fuel gas with a composition shown in Table 4.6. The resulting net power output is thus 150 MW, assuming full nitrogen injection. In this scheme, additional natural gas is required for steam generation in the HRSG, which is supplied as fuel for duct firing. The gas requirement is 1.77 million m^3/d (65.9 TJ/d). The natural gas demands of the co-gen plant are estimated at 3.28 million m^3/d (122 TJ/d). When combined with the natural gas demands of upgrading, the total energy requirements of the Long Lake process after CO_2 retrofit with full H_2 extraction and fuel supplementation amount to 168 TJ/d, or 4.53 million m^3/d.

Table 4.6. Fuel syngas composition and flowrate comparison (dry, mole %)

Stream	No shift	CO shift	CO shift + H_2 extraction	CO shift+H_2 extraction + NG
H_2	13.8	82.2	41.2	31.0
CO	75.7	7.0	23.0	17.0
CO_2	8.1	8.1	26.6	19.8
H_2S	0.7	0.7	2.2	1.7
Ar	1.5	1.6	5.1	3.8
CH_4	0.3	0.3	1.0	26.6
tonne/d	15,832	4,651	3,852	4,858

In terms of CO_2 emissions, our estimate is 9,468 tonne/d in the co-gen flue gas with a concentration of 7% (mole, dry basis). Of these, roughly 30% correspond to steam generation via duct firing; the balance is produced in the gas turbine. These emissions are 2.4 times higher than those of the CO_2 retrofit without natural gas supplementation, but roughly half those of the original process without CO_2 capture. When the emissions from natural gas use in upgrading are considered, the total CO_2 emissions of the Long Lake plant are 11,694 tonne/d.

4.4 POST-COMBUSTION CO_2 CAPTURE OPTION

An additional possibility to capture CO_2 in Long Lake is to implement a post-combustion capture system downstream of the co-generation plant. The advantage of this scheme is that no modifications to the existing facilities are required, as this approach is a "tail-end" solution. Conversely, the main disadvantage is that the CO_2 concentration in the flue gas is lower than that of the previously described solutions, which necessitates a chemical solvent and larger equipment. Figure 4.9 shows the proposed flowsheet for this option.

As mentioned earlier, the conditions of the CO_2-bearing gas are such that a chemical solvent is required for efficient capture. In this study we have assumed a traditional MEA-based plant, currently the most commercial process available. The stripper in the MEA plant requires large quantities of energy to remove the CO_2 from the amine solvent. This energy is customarily supplied as low-pressure steam. In the current application, the amount of steam required is estimated at 1.24 tonne steam/tonne CO_2 captured. This figure is consistent with the literature (Simbeck, 2001, Rubin, 2002).

Our analysis indicates that the amount of steam required in the MEA plant is 27,758 tonne/d. The existing HRSG of the co-gen plant is unlikely to be able to supply this steam. Therefore, we propose that a dedicated natural gas-fired boiler be used to supply the steam demands of the CO_2 capture process. Additional opportunities for heat integration elsewhere in the plant, or the addition of a natural gas boiler with low-pressure extraction steam turbine generator (Simbeck, 2001, Singh, 2003) have been proposed and must be evaluated in further detail in a separate study. In this work, the required power for CO_2 capture and compression is supplied by the existing turbine, as sufficient spare power is available.

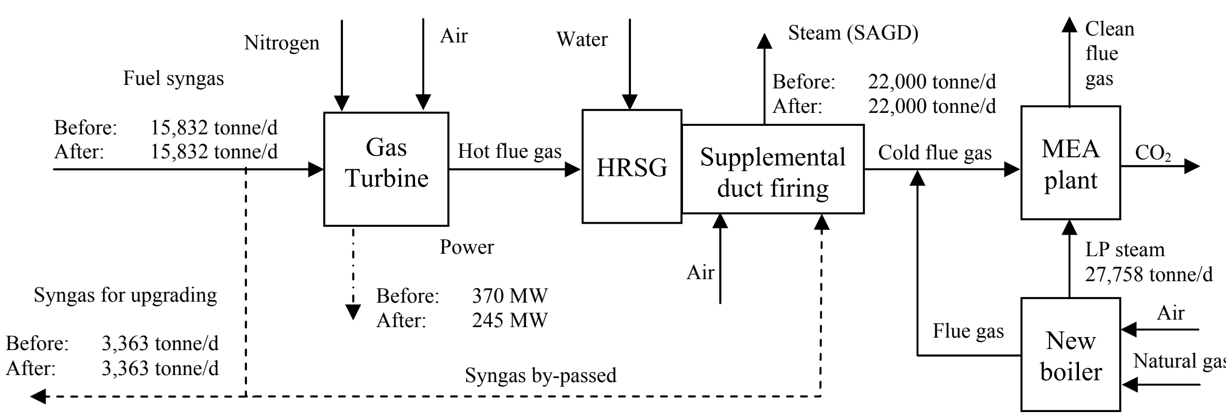

Figure 4.9. CO_2 retrofit with post-combustion capture

The total energy requirements of the CO_2 capture plant are 27,758 tonne/d of steam and 125 MW of power, for a capture efficiency of 90%. The power requirements for CO_2 capture and compression are assumed to be 145 kW/tonne CO_2 (Simbeck, 2001). The net outputs of the co-gen plant after CO_2 retrofit are 245 MWe and 22,000 tonne steam/d. The internal power requirements of the Long Lake plant are estimated at 50 MW, thus, 195 MW are available for sale to the grid.

The net natural gas requirements after CO_2 retrofit amount to 2.9 million m^3/d (107.9 TJ/d). This is 36% less natural gas than that required in the full H_2 extraction case. Also, in the post-combustion capture case, the fuel requirements of the upgrading process are 100% supplied by the syngas, so no additional natural gas is required.

The CO_2 emissions of the co-gen plant after the retrofit are 2,300 tonne/d. In contrast, the emissions of the CO_2 retrofit case without natural gas supplementation using Selexol are 3,901 tonne/d. The CO_2 emissions of the full H_2 extraction case with gas supplementation are 9,468 tonne/d, while the emissions of the original plant are 17,813 tonne/d. However, since syngas is used for energy generation in upgrading, the total CO_2 emissions of the Long Lake plant rise to 6,061 tonne/d. These emissions are practically identical to those of the CO_2 retrofit without natural gas supplementation (6,127 tonne CO_2/d).

The CO_2 captured in the MEA plant is estimated to be 20,698 tonne/day. This figure is roughly 11% higher than the CO_2 captured in the Selexol-based cases. The main reason for the observed increase is the additional CO_2 generated in the new boiler, which is captured in the MEA plant. The CO_2 is delivered at purity in excess of 99.8% and a pressure of 120 bar.

4.5 CASE COMPARISON

Table 4.7 summarizes the options for CO_2 retrofit discussed in this section and compares them to the process pre-CO_2 retrofit. All of the options feature a CO_2 capture efficiency of 90%. In the Selexol plant cases, the assumed CO shift is 90%. In all cases, the steam, hydrogen, and power demands of the Long Lake plant are met.

In terms of steam demands, the post-combustion capture option requires the most steam of all options. This has two direct implications: 1) dedicated steam boilers must be added to the process, and 2) natural gas supplementation is a must, as the syngas is insufficient to satisfy the power and steam needs of the process. The Selexol-based cases have a modest steam requirements increase due to the CO shift, which could potentially be supplied by the existing HRSG.

Table 4.7. Comparison of CO_2 retrofit cases

Feature	Original process	Sweet CO shift	CO shift + full H_2 extraction	Post-combustion CO_2 capture
Solvent for CO_2 capture	N/A	Selexol	Selexol	MEA
H_2 production (tonne/d)	531	531	1,331	531
Steam demands (tonne/d)				
SAGD	22,000	22,000	22,000	22,000
CO shift*	0	7,500	7,500	0
CO_2 plant	0	0	0	27,758
Total	22,000	29,500	29,500	49,758
Power balance (MW)				
CO_2 capture & compression	0	188	188	125
Net available	370	95	150	245
Natural gas supplementation (TJ/d)				
Upgrading	0	46	46	0
Co-gen plant	0	0	122	108
Total	0	46	168	108
CO_2 emissions (tonne/d)				
Co-gen plant	17,813	3,901	9,468	2,300
Upgrading plant	3,761	2,226	2,226	3,761
Total	21,574	6,127	11,694	6,061
CO_2 captured (tonne/d)				
Gasification plant	0	18,681	18,681	0
Co-gen plant	0	0	0	20,698
Purity (mole %)	N/A	92%+	92%+	99+

*Assumed steam:CO ratio = 1

The Selexol-based plants feature the highest power requirements for CO_2 capture and compression. The former is responsible for the largest share of these requirements, due to the need to recycle large volumes of recovered CO_2 in the initial stages of the solvent regeneration. This is done to minimize H_2 losses in the CO_2 stream, and requires additional compression work. In the absence of natural gas supplementation, this results in the largest reduction in power output of the co-gen plant, as the turbine operates at partial capacity. When natural gas is used to fully load the turbine, the net output increases by 50%, with respect to the syngas-only case.

Of the cases that use natural gas for fuel supplementation, the full H_2 extraction design features the largest gas requirements, followed by the post-combustion capture option. This is due to the fact that in the former, purchased gas is required for upgrading operations and for fuel supplementation in the co-gen plant, whereas in the latter natural gas is used exclusively for steam production for CO_2 capture. The CO shift case has the lowest natural gas demands of all.

The net CO_2 reductions achieved by all the options range from 45% to 72% with respect to the original process, prior CO_2 retrofit. The full H_2 extraction case has the highest CO_2 emissions of all cases, due to its extensive use of natural gas as supplemental fuel. On the other hand, the net CO_2 emissions of the post-combustion capture case and the sweet CO shift case are essentially the same.

The emissions reduction of the MEA case is achieved by capturing more CO_2 than its Selexol counterparts. The net CO_2 captured of the former is 11% more than the latter, yet the net emissions reduction of the two is practically identical. In practical terms, this means that CO_2 transport and storage costs of the MEA-based solution would be higher than those of the Selexol solution. This in turn, may translate into higher CO_2 mitigation costs on a per tonne CO_2 captured basis.

It is clear from the results on Table 4.7 that no option has a definite advantage over the others. Multiple tradeoffs between natural gas requirements, value of co-produced energy products, and emissions reductions exist when retrofitting an Opti-Nexen type plant for CO_2 capture. An economic analysis of the above options is imperative to add clarity to the decision-making process.

4.6 ECONOMIC OF CO_2 CAPTURE WITH AMINE

We have estimated the CO_2 capture cost using a chemical absorption process with a CO_2 concentration of 44% in the waste gas stream. Again, the ARC Integrated Economic Model is used to develop the cost estimate. The Capital and Operating Cost Estimates are shown in Table 4.8 and 4.9, respectively.

Table 4.8 Capital cost estimate of a MHI KS-1 CO_2 capture plant from a 44% CO_2 waste gas stream

Flue Gas Desulfurization	\$21.8 MM
CO_2 Recovery	\$80.4 MM
Compression	\$54.5 MM
Utilities - Cooling water system \$33.2 MM - Other utilities \$49.4 MM	\$82.6 MM
Contingency	\$23.9 MM
Total	\$263.3 MM

Table 4.9 Estimate of CO_2 cost using the MHI KS-1 solvent process

2008 Canadian dollars		Cost $/tonne CO_2
Capital Charges		15.2
Fixed Costs		8.6
Variable Costs		39.4
- electricity	4.5	
- natural gas	30.5	
- others	4.4	
Total		63.2

4.7 REFERENCES

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CHAPTER 5

COST CURVES SUMMARY

5.1 CO_2 PRODUCTION FROM HIGH PURITY CO_2 STREAMS

There are three Benfield units operating in the Fort McMurray area – two from Syncrude and one from Suncor. They are used for hydrogen/CO_2 separation in the older hydrogen plants. CO_2 supplies from these units are 1730 ky/year and 280 kt/year, respectively. These streams are essentially pure, 99+% CO_2. To produce CO_2 from these streams does not require any capture operation, just gathering, dehydration and compression.

For an operation of 2 million tonnes per year of CO_2 output, consistent with the scale of operation in the earlier Chapter, the capital cost estimate is $117 million in 2008 Canadian dollars. The operating cost estimate is $25.2 million. The cost of the CO_2 produced would be about $18.8/tonne, as shown in Table 5.1.

Table 5.1. Operating Cost Estimate.

2008 Canadian dollars	Cost $ MM	CO_2 Cost/tonne $/tonne
Capital Costs	$ 117	
- dehydration $5.4 MM		
- Compression $81.3 MM		
- gathering and plant $30.3 MM		
Capital Charges	12.4	6.2
Fixed Costs	3.5	1.75
Variable Costs		
- electricity	19.0	8.5
- TEG	0.4	0.2
- labour	2.3	1.15
Total	37.6	18.8

The compression estimate is based on electric drive, with a power consumption of 119 KWh/tonne of CO_2 and electricity is priced at $80/MWh.
Capital is charged out at an annual rate of 10%, at a 30 years project life.
Fixed operating cost is 3% of capital costs; and labour cost is estimated at 10% of cash costs

5.2 COST CURVES

Table 5.2 summarizes he cost of capturing CO_2 from a 3.5%, 9.2%, 13%, 18.6% and 44% CO_2 waste gas stream. The cost estimate is based on a capture process such as the MHI- KS-1 type solvent. It shows the trend that the cost of CO_2 capture decreases as the CO_2 concentration in the flue gas increases.

Based on the analysis in this Study, CO_2 supply cost curves from the Fort McMurray area in 2020 for the low, medium and high oil production cases are constructed (see Figure 5.1).

Figure 5.2 shows the CO_2 Supply Cost Curves from the Fort McMurray Area in 2020 for Medium Oil Production Case, for SMR, SMR + Gasification and Gasification with Petcoke. With the introduction of gasification, the total CO_2 supplies increase, more so with gasification of bitumen residues than petcoke. It also reveals the emergence of significant quantities of the ~ 50% CO_2 concentration streams.

Table 5.2. Estimate of CO_2 cost for five CO_2 concentrations of 3.5%, 9.2% 13%, 18.6% and 44% CO_2 streams

2008 Canadian dollars $/tonne CO_2	3.5% CO_2*	9.2% CO_2	13% CO_2	18.6% CO_2	44% CO_2
Capital Costs $ MM	1234	629	479.8	396.8	263.3
Capital Charges	71.2	36.3	28.8	22.9	15.2
Fixed Costs	43.8	20.5	16.4	13.1	8.6
Variable Costs					
- electricity	23.2	10.5	8.5	6.6	4.5
- natural gas	26.5	28.4	30.2	28.8	30.5
- others	6.9	5.9	6.0	4.6	4.4
Total	171.6	101.6	89.8	76.0	63.2

* the waste gas stream does not contain sulphur, therefore desulphurization is not required

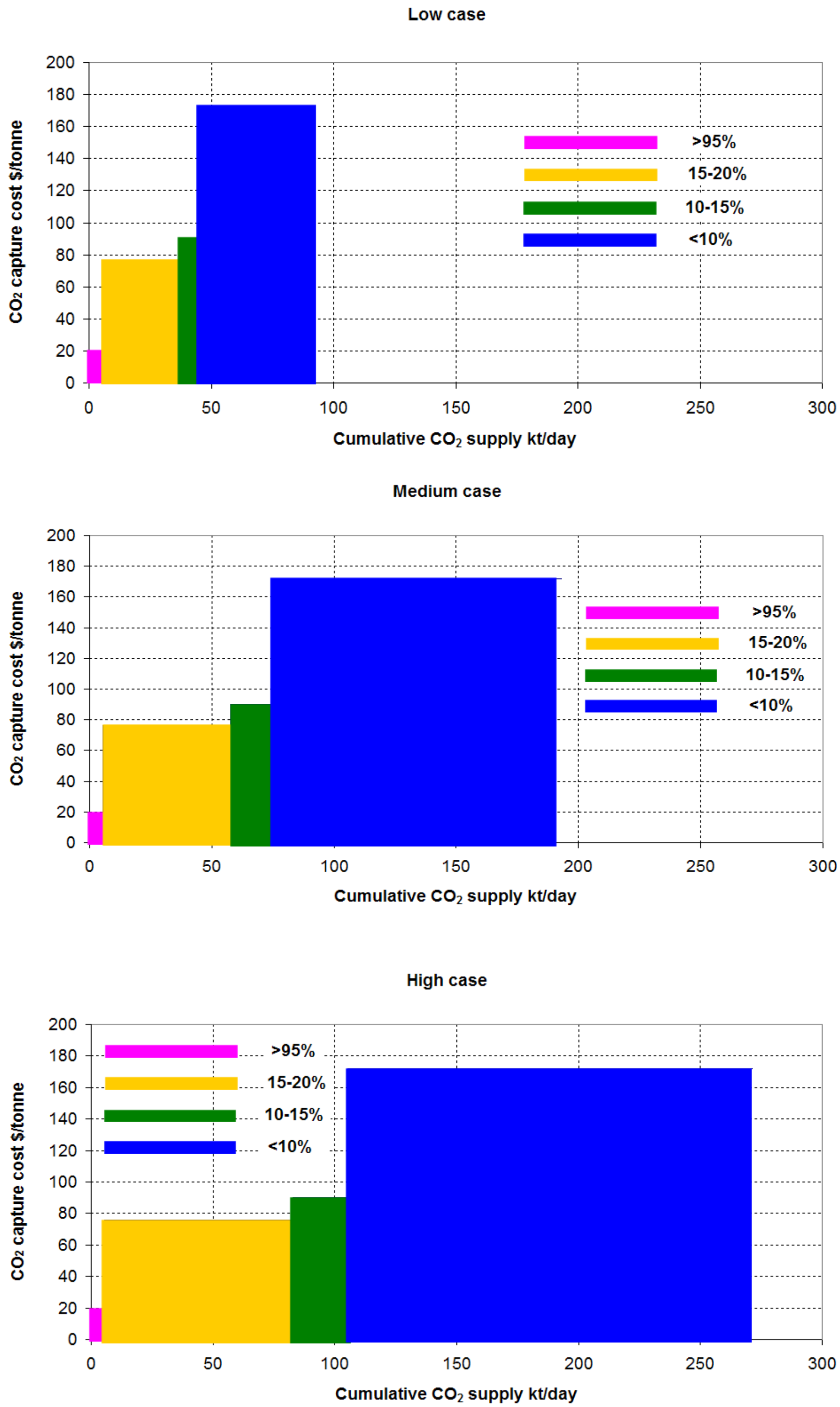

Figure 5.1. CO_2 supply cost curves from the Fort McMurray area in 2020.

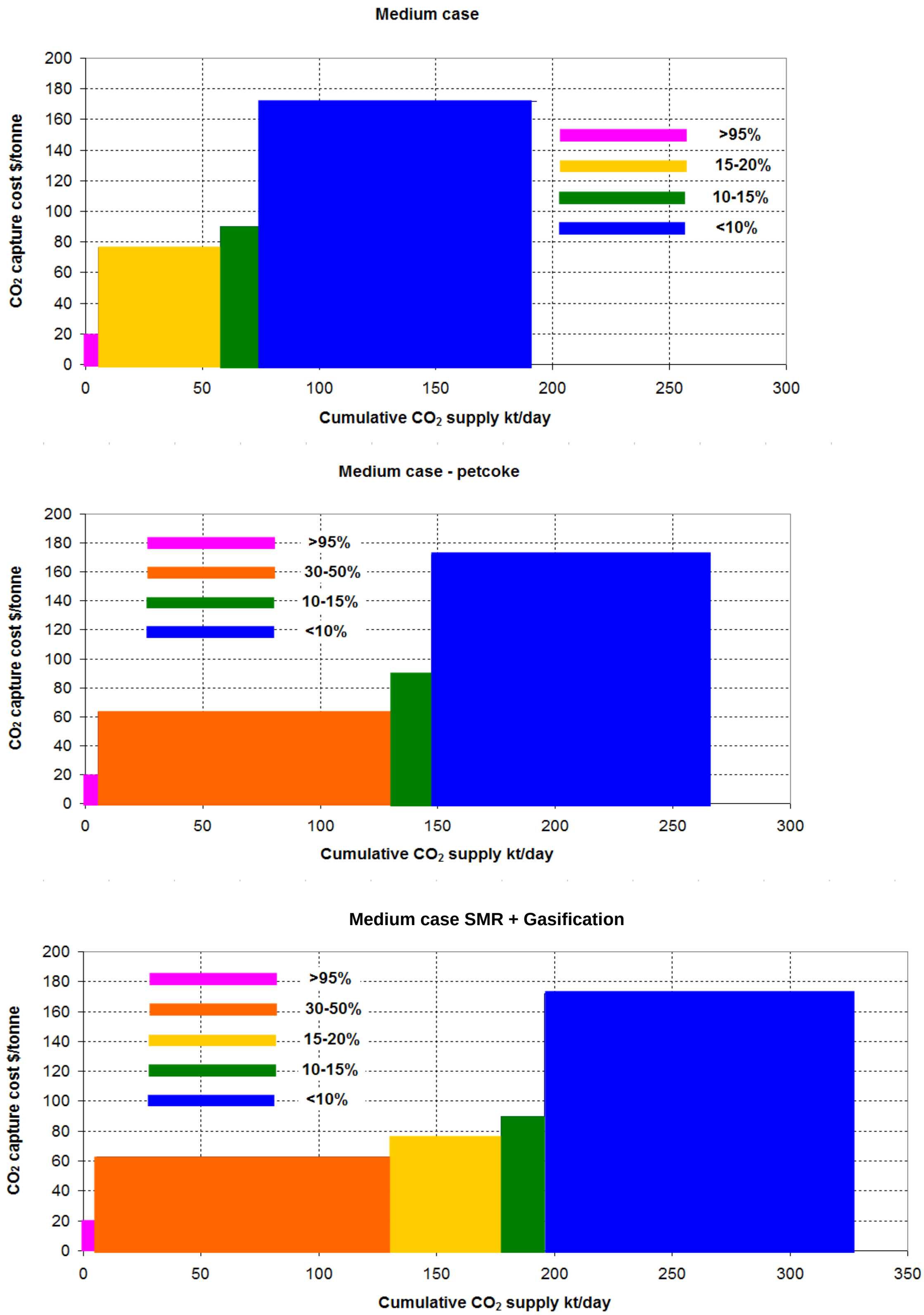

Figure 5.2. CO_2 supply cost curves from the Fort McMurray Area in 2020 for medium oil production case, for SMR, SMR + Gasification and Gasification with Petcoke

5.3 SUGGESTIONS FOR FURTHER RESEARCH

We have built a CO_2 supply model based on first principles and followed the previous work of Dr. Ordorica-Garcia at the University of Waterloo. The CO_2 supply would be a function of the type of fuels, type of energy commodities and type of processes used in the oil sands operations. The model will benefit from further segregation of the quality and quantities of fuel gas generated internally within the plant.

We have also investigated retrofit options for CO_2 capture for the Opti-Nexen operation in Long Lake. We highlighted the complexity of the engineering issues. To go further than what we have done would require the support and a large degree of co-operation from the operator. This would be an interesting project and would put the operator in a much better position in selecting the optimal capture technology and determining the cost of capturing the CO_2 from the operation.

One aspect we have not investigated in this Study is the retrofit options for the steam generation in the SAGD operations. We noted some patents related to using oxy-fuel combustion in steam generation as a mean of generating higher CO_2 concentration in the flue gas. Given the large volumes of low concentration CO_2 in the CO_2 supply, application of oxy-fuel combustion to SAGD for CO_2 mitigation is a worthwhile R&D project.

APPENDIX 1

Plant	Status (Apr '08)	Production (bbl/d)															
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CNRL	**Operating**																
Horizon	**Construction**				114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
(Upgrading)	**Approved**							118,000	118,000	118,000	118,000	118,000	118,000	118,000	118,000	118,000	118,000
	Application																
	Disclosure																
	Announced											125,000	125,000	265,000	265,000	265,000	265,000
	Total (max)	-	-	-	114,000	114,000	114,000	232,000	232,000	232,000	232,000	357,000	357,000	497,000	497,000	497,000	497,000
Opti-Nexen	**Operating**																
Long Lake	**Construction**			16,000	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500	58,500
(Upgrading)	**Approved**										58,500	58,500	58,500	58,500	58,500	58,500	58,500
	Application																
	Disclosure																
	Announced												58,500	58,500	117,000	117,000	175,500
	Total (max)	-	-	16,000	58,500	58,500	58,500	58,500	58,500	58,500	117,000	117,000	175,500	175,500	234,000	234,000	292,500
Suncor	**Operating**	161,560	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000
Base & Millenium &	**Construction**				97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000	97,000
Voyageur	**Approved**						127,000	127,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
(Upgrading)	**Application**																
	Disclosure																
	Announced																
	Total (max)	161,560	260,000	260,000	357,000	357,000	484,000	484,000	547,000	547,000	547,000	547,000	547,000	547,000	547,000	547,000	547,000
Syncrude	**Operating**	250,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
Mildred Lake & Aurora	**Construction**																
(Upgrading)	**Approved**																
	Application																
	Disclosure																
	Announced									40,000	40,000	40,000	40,000	160,000	160,000	160,000	160,000
	Total (max)	250,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	390,000	390,000	390,000	390,000	510,000	510,000	510,000	510,000
Value Creation	**Operating**																
Terre de Grace	**Construction**																
(Upgrading)	**Approved**																
	Application						8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400
CNRL	**Operating**																
Horizon	**Construction**				135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000
(mining)	**Approved**							135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000	135,000
	Application																
	Disclosure																
	Announced											145,000	145,000	307,000	307,000	307,000	307,000
	Total (max)	-	-	-	135,000	135,000	135,000	270,000	270,000	270,000	270,000	415,000	415,000	577,000	577,000	577,000	577,000
Imperial/ExxonMobil	**Operating**																
Kearl Lake	**Construction**																
(mining)	**Approved**						100,000	100,000	200,000	200,000	200,000	200,000	200,000	200,000	300,000	300,000	300,000
	Application																
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	100,000	100,000	200,000	200,000	200,000	200,000	200,000	200,000	300,000	300,000	300,000
Petro-Canada	**Operating**																
Fort-Hills	**Construction**																
(mining)	**Approved**							165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
	Application																
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	-	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
Shell-AOSP	**Operating**	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000	155,000
Muskeg River & Jackpine & Pierre River	**Construction**						100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
(mining)	**Approved**						115,000	115,000	215,000	215,000	215,000	215,000	215,000	215,000	215,000	215,000	215,000
	Application										100,000	100,000	100,000	100,000	200,000	200,000	200,000
	Disclosure																
	Announced																
	Total (max)	155,000	155,000	155,000	155,000	155,000	370,000	370,000	470,000	470,000	570,000	570,000	570,000	570,000	670,000	670,000	670,000
Suncor	**Operating**	195,450	260,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000	294,000
Millenium & Steepbank &	**Construction**			4,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000	27,000
Voyageur	**Approved**																
(mining)	**Application**							120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000
	Disclosure																
	Announced																
	Total (max)	195,450	260,000	298,000	321,000	321,000	321,000	441,000	441,000	441,000	441,000	441,000	441,000	441,000	441,000	441,000	441,000

Plant	Status (Apr '08)	Production (bbl/d)															
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Syncrude	Operating	262,401	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000	407,000
Mildred Lake & Aurora	Construction																
(mining)	Approved																
	Application																
	Disclosure																
	Announced							46,500	46,500	46,500	46,500	186,000	186,000	186,000	186,000	186,000	186,000
	Total (max)	262,401	407,000	407,000	407,000	407,000	407,000	453,500	453,500	453,500	453,500	593,000	593,000	593,000	593,000	593,000	593,000
Total E&P	Operating																
Joslyn	Construction																
(mining)	Approved																
	Application									50,000	50,000	50,000	100,000	100,000	100,000	100,000	100,000
	Disclosure																
	Announced															50,000	50,000
	Total (max)	-	-	-	-	-	-	-	-	50,000	50,000	50,000	100,000	100,000	100,000	150,000	150,000
Synenco	Operating																
Northern Lights	Construction																
(mining)	Approved																
	Application						57,250	57,250	114,500	114,500	114,500	114,500	114,500	114,500	114,500	114,500	114,500
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	57,250	57,250	114,500	114,500	114,500	114,500	114,500	114,500	114,500	114,500	114,500
UTS/Teck Cominco	Operating																
Equinox & Frontier	Construction																
(mining)	Approved																
	Application																
	Disclosure										50,000	150,000	150,000	210,000	210,000	210,000	210,000
	Announced																
	Total (max)	-	-	-	-	-	-	-	-	-	50,000	150,000	150,000	210,000	210,000	210,000	210,000
Chevron Canada	Operating																
Ells River	Construction																
(SAGD)	Approved																
	Application																
	Disclosure																
	Announced											100,000	100,000	100,000	100,000	100,000	100,000
	Total (max)	-	-	-	-	-	-	-	-	-	-	100,000	100,000	100,000	100,000	100,000	100,000
CNRL	Operating																
Birch & Kirby &	Construction																
Gregoire Lake	Approved																
(SAGD)	Application							30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
	Disclosure																
	Announced									30,000	60,000	60,000	90,000	120,000	120,000	120,000	150,000
	Total (max)	-	-	-	-	-	-	30,000	30,000	60,000	90,000	90,000	120,000	150,000	150,000	150,000	180,000
Connacher	Operating			10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Great Divide	Construction																
(SAGD)	Approved																
	Application					10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	Disclosure																
	Announced																
	Total (max)	-	-	10,000	10,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
ConocoPhillips	Operating		25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Surmont	Construction																
(SAGD)	Approved				25,000	25,000	25,000	50,000	50,000	50,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000
	Application																
	Disclosure																
	Announced																
	Total (max)	-	25,000	25,000	50,000	50,000	50,000	75,000	75,000	75,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Devon	Operating																
Jackfish	Construction				35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
(SAGD)	Approved																
	Application						35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
	Disclosure																
	Announced																
	Total (max)	-	-	-	35,000	35,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Encana	Operating	34,922	50,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Borealis, Christina & Foster	Construction				8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800	8,800
(SAGD)	Approved				30,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
	Application						40,000	110,000	110,000	110,000	110,000	145,000	145,000	145,000	145,000	145,000	145,000
	Disclosure																
	Announced								30,000	60,000	90,000	120,000	150,000	150,000	150,000	150,000	150,000
	Total (max)	34,922	50,000	70,000	108,800	138,800	178,800	248,800	278,800	308,800	338,800	403,800	433,800	433,800	433,800	433,800	433,800
Husky	Operating																
Sunrise	Construction																
(SAGD)	Approved								50,000	50,000	100,000	100,000	150,000	150,000	200,000	200,000	200,000
	Application																
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	-	-	50,000	50,000	100,000	100,000	150,000	150,000	200,000	200,000	200,000

Plant	Status (Apr '08)	Production (bbl/d)															
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
JACOS	Operating	7,754	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Hangingstone	Construction																
(SAGD)	Approved																
	Application																
	Disclosure						25,000	25,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
	Announced																
	Total (max)	7,754	10,000	10,000	10,000	10,000	35,000	35,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
KNOC	Operating																
Black Gold	Construction																
(SAGD)	Approved																
	Application						10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
MEG	Operating																
Christina Lake	Construction				23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880
(SAGD)	Approved																
	Application																
	Disclosure																
	Announced																
	Total (max)	-	-	-	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880	23,880
NAOSC/StatoilHydro	Operating																
Kai Kos Dehseh	Construction					10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
(SAGD)	Approved																
	Application						10,000	30,000	70,000	110,000	150,000	150,000	170,000	190,000	210,000	210,000	210,000
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	10,000	20,000	40,000	80,000	120,000	160,000	160,000	180,000	200,000	220,000	220,000	220,000
Opti-Nexen	Operating			20,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000	72,000
Long Lake	Construction																
(SAGD)	Approved																
	Application										70,000	70,000	140,000	140,000	140,000	140,000	140,000
	Disclosure																
	Announced														72,000	72,000	144,000
	Total (max)	-	-	20,000	72,000	72,000	72,000	72,000	72,000	72,000	142,000	142,000	212,000	212,000	284,000	284,000	356,000
Petro-Canada	Operating	21,300	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000
MacKay river	Construction																
(SAGD)	Approved							40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
	Application																
	Disclosure																
	Announced																
	Total (max)	21,300	33,000	33,000	33,000	33,000	33,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000
Suncor	Operating	19,194	70,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000
Firebag	Construction					68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000	68,000
(SAGD)	Approved																
	Application						68,000	136,000	204,000	204,000	204,000	204,000	204,000	204,000	204,000	204,000	204,000
	Disclosure																
	Announced																
	Total (max)	19,194	70,000	95,000	95,000	163,000	231,000	299,000	367,000	367,000	367,000	367,000	367,000	367,000	367,000	367,000	367,000
Total	Operating	2,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Joslyn	Construction																
(SAGD)	Approved																
	Application					15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
	Disclosure							15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
	Announced																
	Total (max)	2,000	12,000	12,000	12,000	27,000	27,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000
Value Creation	Operating																
Terre de Grace	Construction																
(SAGD)	Approved																
	Application						10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	Disclosure																
	Announced																
	Total (max)	-	-	-	-	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Enerplus	Operating																
Kirby	Construction																
(SAGD)	Approved																
	Application																
	Disclosure																
	Announced							10,000	10,000	10,000	10,000	10,000	10,000	35,000	35,000	35,000	35,000
	Total (max)	-	-	-	-	-	-	10,000	10,000	10,000	10,000	10,000	10,000	35,000	35,000	35,000	35,000

Plant	Status (Apr '08)	Production (bbl/d)															
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Patch	**Operating**																
Ells River	**Construction**																
(SAGD)	**Approved**																
	Application																
	Disclosure																
	Announced						10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	Total (max)	-	-	-	-	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Petrobank (Whitesands)	**Operating**																
May River	**Construction**																
(SAGD)	**Approved**																
	Application																
	Disclosure					10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	Announced																
	Total (max)	-	-	-	-	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Total Mining	**Operating**	612,851	822,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000	856,000
bitumen	**Construction**	-	-	4,000	162,000	162,000	262,000	262,000	262,000	262,000	262,000	262,000	262,000	262,000	262,000	262,000	262,000
bbl/d	**Approved**	-	-	-	-	-	215,000	515,000	715,000	715,000	715,000	715,000	715,000	715,000	815,000	815,000	815,000
	Application	-	-	-	-	-	57,250	177,250	234,500	284,500	384,500	384,500	434,500	434,500	534,500	534,500	534,500
	Disclosure	-	-	-	-	-	-	-	-	-	50,000	150,000	150,000	210,000	210,000	210,000	210,000
	Announced	-	-	-	-	-	-	46,500	46,500	46,500	46,500	331,000	331,000	493,000	493,000	543,000	543,000
	Total (max)	612,851	822,000	860,000	1,018,000	1,018,000	1,390,250	1,856,750	2,114,000	2,164,000	2,314,000	2,698,500	2,748,500	2,970,500	3,170,500	3,220,500	3,220,500
Total Upgrading	**Operating**	411,560	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000	610,000
SCO	**Construction**	-	-	16,000	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500	269,500
bbl/d	**Approved**	-	-	-	-	-	127,000	245,000	308,000	308,000	366,500	366,500	366,500	366,500	366,500	366,500	366,500
	Application	-	-	-	-	-	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400	8,400
	Disclosure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Announced	-	-	-	-	-	-	-	-	40,000	40,000	165,000	223,500	483,500	542,000	542,000	600,500
	Total (max)	411,560	610,000	626,000	879,500	879,500	1,014,900	1,132,900	1,195,900	1,235,900	1,294,400	1,419,400	1,477,900	1,737,900	1,796,400	1,796,400	1,854,900
Total SAGD	**Operating**	85,170	200,000	275,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000	327,000
bitumen	**Construction**	-	-	-	67,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680	145,680
bbl/d	**Approved**	-	-	-	55,000	85,000	85,000	150,000	200,000	200,000	275,000	275,000	325,000	325,000	375,000	375,000	375,000
	Application	-	-	-	-	25,000	198,000	386,000	494,000	534,000	644,000	679,000	769,000	789,000	809,000	809,000	809,000
	Disclosure	-	-	-	-	10,000	35,000	50,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000
	Announced	-	-	-	-	-	10,000	20,000	50,000	110,000	170,000	300,000	360,000	415,000	487,000	487,000	589,000
	Total (max)	85,170	200,000	275,000	449,680	592,680	800,680	1,078,680	1,291,680	1,391,680	1,636,680	1,801,680	2,001,680	2,076,680	2,218,680	2,218,680	2,320,680