

Evaluating CO₂ Capture in the Oil Sands

Presented By

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Background

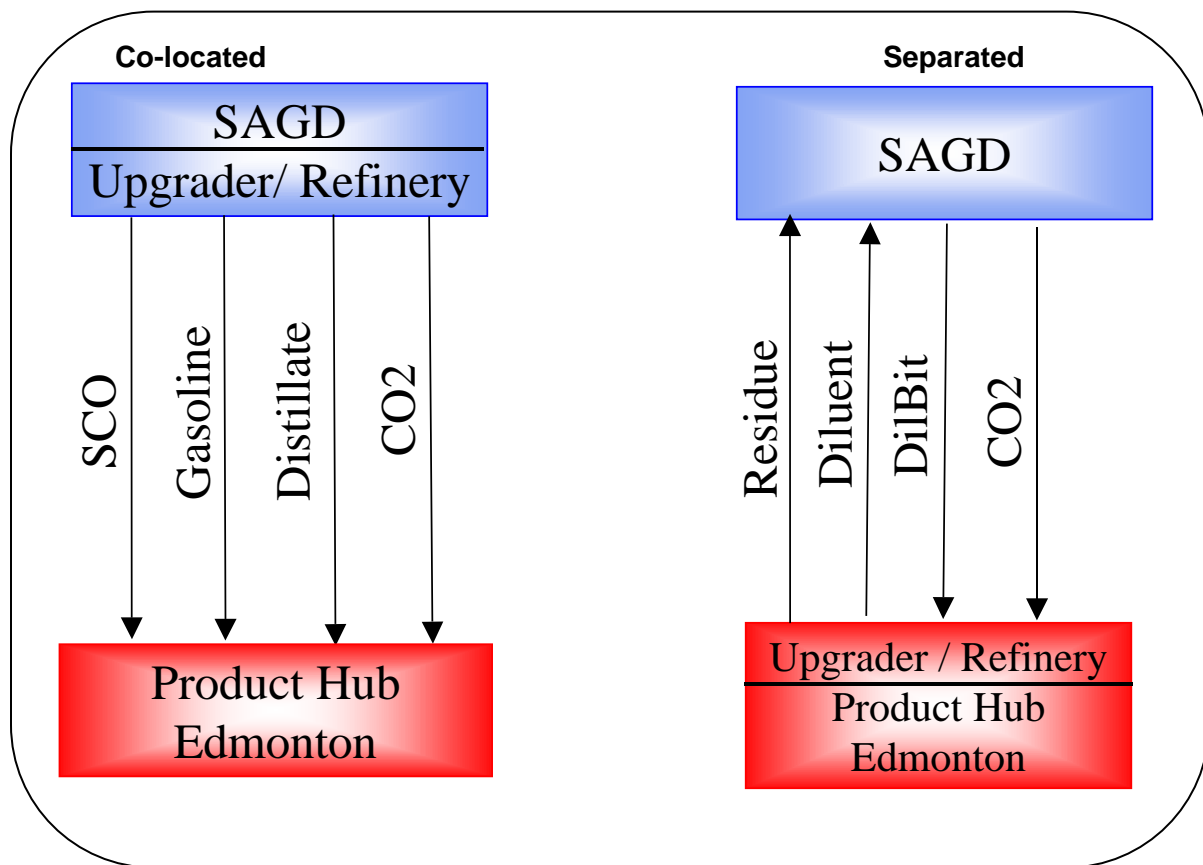
Given the concern over CO₂ emissions and the cost of capture in the Alberta Oil Sands, AERI and Jacobs Consultancy recently completed a technology-based study to quantify the answers to the following issues:

- Impact of upgrading location (near SAGD or Industrial Heartland) on CO₂ capture and profitability;
- Impact of primary upgrading technology on CO₂ capture and, alternatively, the impact of CO₂ capture on technology selection. For the purposes of the study, we evaluated CO₂ capture for all concentrated sources such as the Steam Methane Reformer (SMR) and gasifier, as well as amine based post combustion capture for large point sources of dilute CO₂.
- Impact of upgrading conversion levels as defined by the amount of bitumen converted to bottomless material instead of coke or pitch and hydrogen demand on CO₂ emissions.

The work builds from two recent AERI studies on emerging technologies for upgrading under AERI's Hydrocarbon Upgrading Demonstration Program (HUDP) initiative, and a study completed in conjunction with Alberta Environmental on Alternative Fuels for Steam Assisted Gravity Drainage (SAGD) steam generation. The focus was to understand the economic benefits and CO₂ emission reductions of co-locating various technology platforms with SAGD oil production in an effort to share infrastructure and utilities, avoid diluted bitumen transport, diluent purchase and recycle, and finally, provide an energy off take for residue produced from upgrading.

A total of 15 configurations were evaluated both with and without carbon capture. For the purposes of the study, "co-located" meant that the upgrader was positioned adjacent or relatively close to the SAGD production facility to allow for easy transport of steam, power, bitumen, residue or gasification products between the two sites. "Separate facilities" assumed the upgrading facility was located in the Alberta Industrial Heartland close to transportation hubs. Diluted bitumen and diluent were the primary oil products transported between the SAGD production site and the upgrader. Figure 1 below is a high level example block flow diagram of co-located and separate production and upgrading facilities:

Figure 1. High Level Block Flow Diagrams



The upgrading technologies and configurations we considered consisted of the following main types:

- High Conversion—Slurry phase hydrocracking (SP HCK)
- Ebullating bed hydrocracking (EB HCK)
- Delayed coking
- Gasification of residue
- Combustion of residue

The scope of the study did not include a Life Cycle Analysis (LCA) of CO₂ for each case; rather, it focused on the CO₂ generated and released from the production sites at a granular level. Overall the relative results are applicable as input to a LCA study and, among similar cases, accurately determines the effect of co-locating facilities. However, dissimilar cases should be evaluated via LCA to accurately understand the GHG emissions, especially with regard to:

- SCO versus fuels products—There are inherent inefficiencies in upgrading to SCO and then refining SCO to fuels products. Without exception, fuels produced from a combined upgrader/refinery will have a lower GHG burden than a similar technology case with the SCO intermediary.
- Coke handling or residue disposition—Land filling coke in Alberta effectively stores a significant portion of the carbon in the bitumen. However, LCA is required to accurately reflect the impact of the coke disposition if it is used for fuel elsewhere as opposed to being stored indefinitely.
- SAGD power generation—Bitumen producers that incorporate cogeneration of power in the steam cycle have a lower overall efficiency but may, in fact, reduce the GHG calculated by LCA by offsetting power produced via a coal-based power plant.

From our initial hypothesis, we concluded the following:

- Upgrading Location
 - Generally, location has minor impact on CO₂ footprint
 - Regional construction cost differences have a dominant influence on economics
- Upgrading Technology
 - Impacts CO₂ emissions
 - CO₂ capture has a minor impact on selection of upgrading technology
- Hydrogen Generation
 - Gasification is better suited for CO₂ capture than Steam Methane Reforming

Cases Evaluated

The cases evaluated are summarized in Table 1 on the following page.

Table 1. Cases Evaluated

Case (Phase 1 Basis)	Co-located	Upgrader			SAGD			Objective
		Primary Upgrading Step	Product	Residue	Fuel for Steam	Boiler Tech	Water Treat Tech	
1 (BC1)	N	DC	SCO	Landfill	NG	OTSG	WLS	Base Case
2 (BC1)	N	DC	SCO	Landfill	VB-emulsion	Drum Boiler	Evap	Alternate Fuel - clear definition needed for consistency with Alternate Fuels study
3 (BC1g)	N	DC	SCO	Gasifier	NG	OTSG	WLS	Gasifier impact
4 (BC2g)	N	DC	Fuels	Gasifier	NG	OTSG	WLS	Fuels versus SCO
5 (4B)	N	Slurry Phase HC	Fuels	Gasifier	NG	OTSG	WLS	H2 addition case
6 (4B sans gasifier)	N	Slurry Phase HC	Fuels	Emulsion	Emulsion/NG	Drum Boiler	Evap	H2 addition case
7a (BC1)	Y	DC	SCO	CFBB	Petcoke	CFBB	Evap	Alternate Fuel - clear definition needed for consistency with Alternate Fuels study
7b (BC1)	Y	DC	SCO	CFBB	Petcoke Oxyfuels	CFBB	Evap	With Oxy Fuels
8 (BC1g)	Y	DC	SCO	Gasifier	Gasifier/NG	OTSG	WLS	Gasifier impact in field
9	Y	DC	Fuels	Gasifier	NG	OTSG	WLS	Fuels versus SCO in field
10 (4B sans gasifier)	Y	Slurry Phase HC	Fuels	Emulsion	Emulsion	Drum Boiler	Evap	H2 addition - field location; capital cost delta vs. case 6
11 (2g2)	Y	C4 SDA	SCO	Gasifier	Gasifier	OTSG	WLS	Similar to Opti- Nexen (publicly available information) with CO2 capture
12 (New)	N	EB HCK	SCO	Emulsion	Emulsion/NG	Drum Boiler/OTSG	Evap	H2 addition case - most common technology
12a (New)	N	EB HCK	SCO	SCO	NG	CFBB	Evap	H2 addition case - most common technology
13 (New)	Y	EB HCK	SCO	Gasifier	Gasifier/NG	OTSG	WLS	H2 addition- most common in field
13a (New)	N	EB HCK	SCO	Gasifier	NG	OTSG	WLS	H2 addition- most common in field

The various cases were compared based on NPV and CO₂ generation with and without carbon capture and storage (CCS). For the purposes of the study, CCS costs only included the capital and operating costs for the ISBL facilities including separation, concentration, and compression to roughly 2000 psig. Pipeline costs, drilling, and other costs for the CO₂ are not included. It was assumed that for a comparative basis, all cases would incur the sequestration costs in

proportion to the CO₂ generated, and the relative results would be accurate without including them. In this level of analysis, we factor OSBL costs of ISBL costs for estimating overall facility capital costs.

Basis

To establish a basis for the study, we selected a SAGD facility and upgrading complex with the ability to process about 200,000 BPD of bitumen. The SAGD size was set to match and would obviously include multiple trains of boilers and well pairs. We assumed that the large SAGD complex could be constructed with the same efficiency and effectiveness of the smaller complexes we currently see being constructed. For the study, we selected three price sets, but settled on an average of \$95/bbl WTI (2008 US dollars) for a long-range average. The natural gas price was selected for the various WTI prices based on historical data. The price sets were as follows:

WTI (\$/Bbl)	Natural Gas (\$/MMBTU)
\$60	\$7.24
\$95	\$9.65
\$120	\$11.51

US\$, 2008

For the most part, capturable CO₂ was assumed for any high concentration streams, such as the gasifier and the feed side of the Steam Methane Reformer (SMR). In addition, we included two large single point sources of dilute CO₂: the SAGD boilers and the Fluidized Catalytic Cracking unit (FCC), which burns coke deposited on the catalyst during the continuous regeneration process. Other dilute sources such as the miscellaneous process heaters and steam generators in the upgrader/refiner were not included as capturable CO₂. Furthermore, imported power carried an indirect CO₂ burden that was not considered capturable.

From a cost standpoint, any emitted (non-captured) CO₂ was assumed to have a penalty of \$25/MT in all cases with or without CO₂ capture.

The following capture methods were selected:

- For all low pressure CO₂ sources such as the SAGD boiler flue gas, the FCC regenerator and the feed side of the SMR, amine capture technology was selected. The rich amine is regenerated using steam to drive out the CO₂.

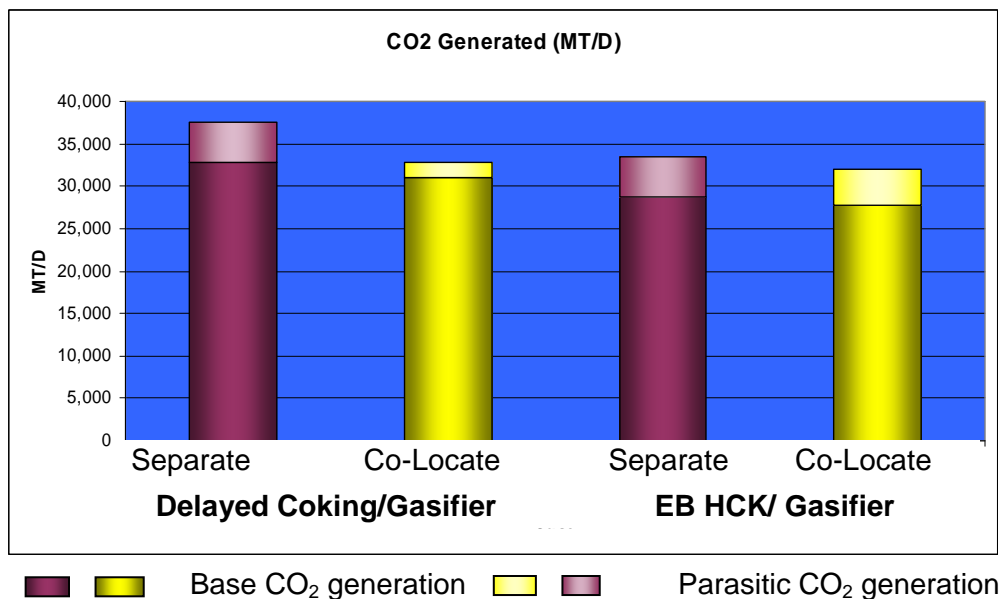
- For the gasifier, a physical solvent such as RECTISOL® or SELEXOL® was used downstream of a sour shift at relatively high syn gas pressure. The high absorption pressure allows release of the CO₂ gas via flashing of the rich solvent without consuming large quantities of steam.

Results

Co-location Benefits

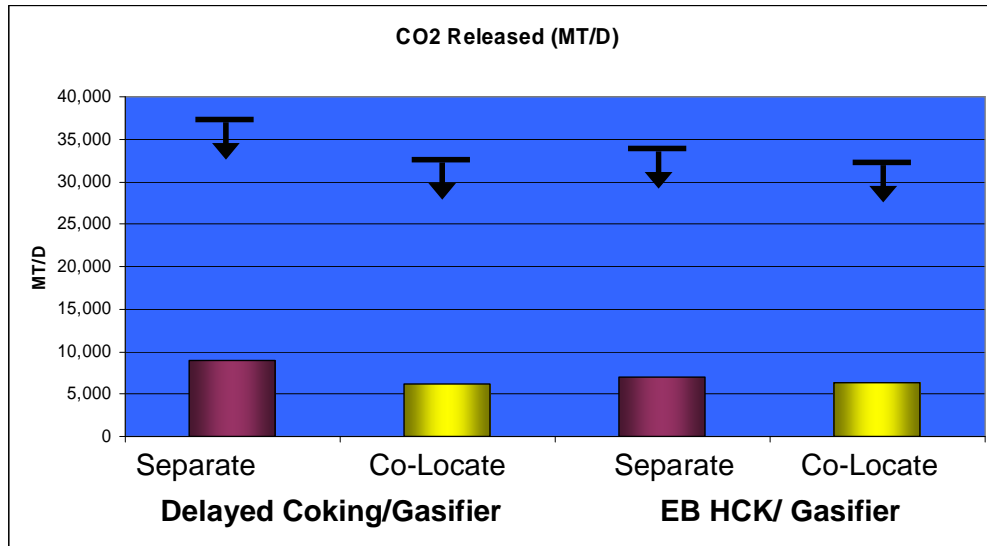
To understand the CO₂ and NPV impact of co-locating the upgrading facility with the SAGD facility, we selected two commercially available technologies with gasification as shown in Figures 2 and 3. In the figures, the two bars on the left reflect a delayed coker-based upgrader with a gasifier consuming the coke to produce hydrogen, power, and fuel for SAGD. The two bars on the right reflect an EB HCK-based upgrader with a gasifier consuming the unconverted oil (UCO) to produce hydrogen, power, and fuel for SAGD. The yellow bars represent the situation where the upgrader is located near the SAGD facility, while the dark red bars represent the situation with the upgrader located in the Industrial Heartland near Edmonton. Figure 2 shows the combined CO₂ capture emissions of the SAGD and upgrading complex without CO₂ capture.

Figure 2. CO₂ Emissions without CO₂ Capture



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Figure 3. CO₂ Emissions with CO₂ Capture



From figures 2 and 3, we see a minor change in overall CO₂ emissions by locating the upgrading complex near the SAGD complex (co-location). In general, among all 15 cases, we found that the synergies that result from co-location are small and result in very little change in the overall CO₂ emissions. This is due primarily because the anticipated synergies gained in the utility systems and heat integration are small for the following reasons:

- SAGD and upgrading complexes use completely different steam systems. The SAGD operation uses a large quantity of high-pressure steam from poor-quality recycled water in direct contact with the oil. The upgrading complex uses several lower pressure steam levels from high-quality water in indirect contact with the process streams.
- The produced bitumen/water from the SAGD operation must be cooled for water removal, so hot direct feed is not an option.
- If using the upgrading residue (coke or pitch) as a fuel for SAGD, CO₂ emissions increase dramatically due to the higher carbon content of the fuel, so gasification is a better option. Once gasification is installed, it would be much simpler to produce hydrogen for the upgrader, leaving almost nothing for the SAGD operation.

The relative NPV of the four cases are shown in figures 4 and 5. The NPV's are relative to a selected base case of delayed coking based upgrader in the industrial heartland and natural gas fired SAGD. Figure 4 is the combined NPV of the facilities without CO₂ capture, while Figure 5 is with CO₂ capture (including capital and operating costs associated with CO₂ capture. The NPV for the co-located facilities is dramatically lower—primarily driven by regional differences in capital costs between the Ft. McMurray area and the Industrial Heartland. This difference has been exacerbated by the recent three- to five-year cost escalation. With Figure 5, we see almost no change in the relative NPV's because the operating costs associated with the co-located facilities are not dramatically reduced and the transportation cost savings are small. This, again, is due to relatively low operational synergy between SAGD and upgrading.

Figure 4. NPV without CO₂ Capture

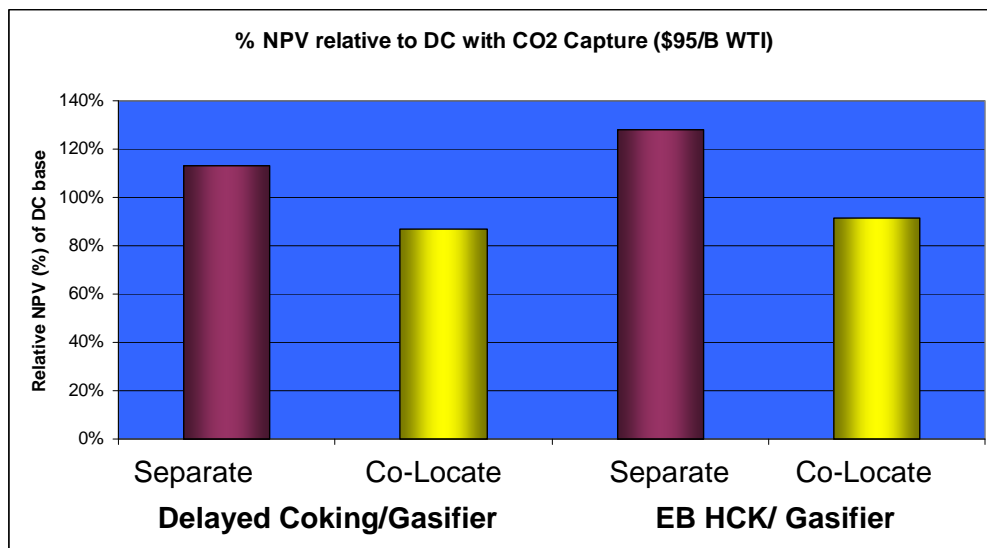
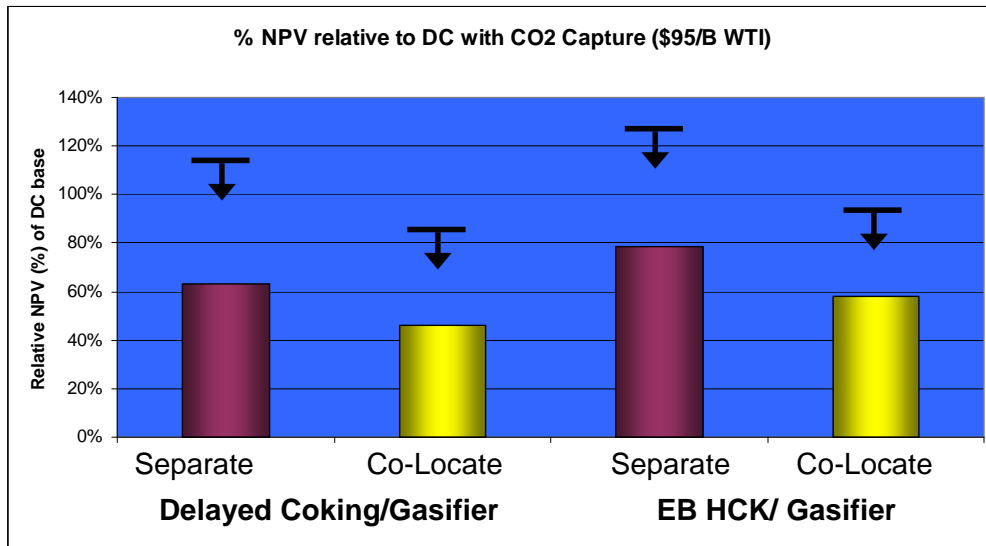


Figure 5. NPV with CO₂ Capture



Technology Selection

To evaluate the impact of CO₂ capture on technology selection, we selected three primary upgrading technologies—delayed coking, EB HCK, and SP HCK. Delayed coking is the most widely used technology and represents the most common carbon rejection technology, while EB HCK is the only commercialized hydrogen addition technology offering in the upgrading of oil sand bitumen. SP HCK, although not commercialized, has been demonstrated and represents a high conversion technology using hydrogen addition. We evaluated all three within the context the following coke or pitch dispositions:

- Delayed coking – storage of coke in Alberta or gasifying the coke for upgrader hydrogen, power and steam
- EB HCK – blending of pitch with the SCO or gasifying the pitch upgrader hydrogen, power and steam
- SP HCK – combusting the pitch for SAGD steam or gasifying the pitch upgrader hydrogen, power and steam

The NPV results are summarized in Figures 6 and 7:

Figure 6. NPV Results without CO₂ Capture

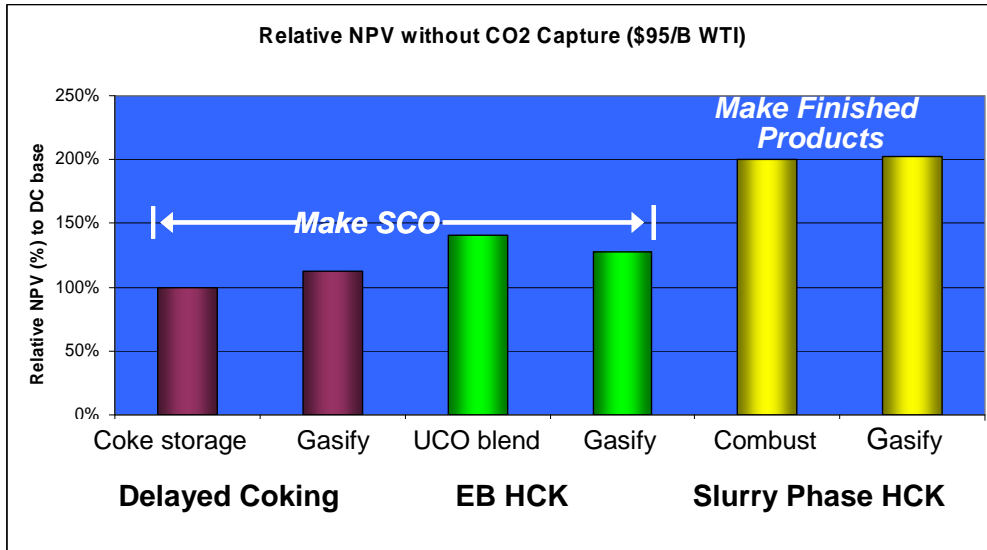
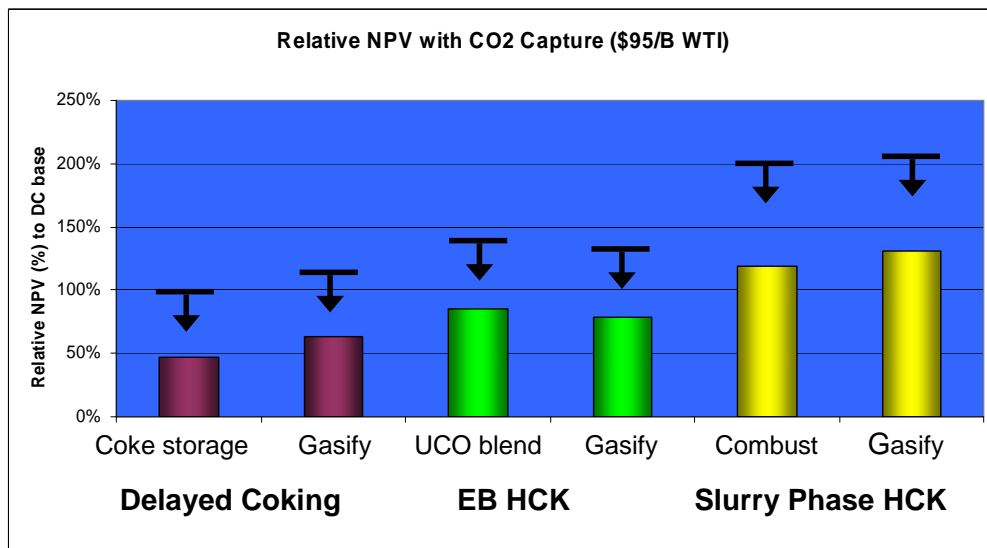


Figure 6 shows an increase in NPV in moving from delayed coking to EB HCK and finally to high conversion SP HCK producing finished products. This was expected and is consistent with earlier studies. However, the point was to understand how CO₂ capture impacted technology selection. Figure 7 shows the NPV after CO₂ capture. Capital and operating costs are included.

Figure 7. NPV Results with CO₂ Capture



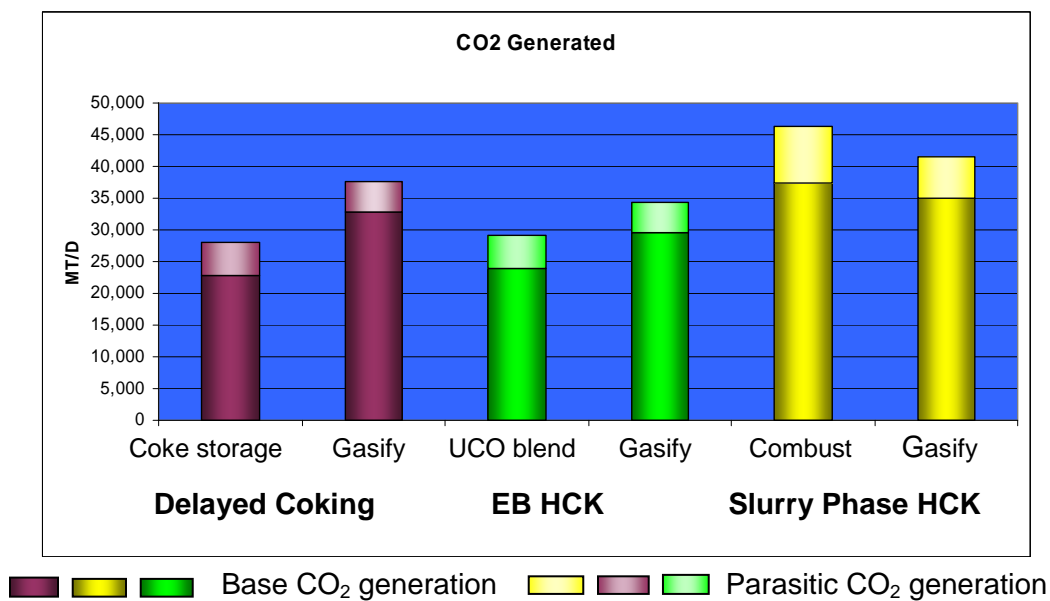
CO₂ capture reduces the NPV of all the cases, but does not change the relative ranking of the different technologies. EB HCK shows superior economics to delayed coking and SP HCK has

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the best economics, though the advantage is not as large as without CO₂ capture. This is largely due to the amount of CO₂ that has to be captured associated with the higher hydrogen demand. At the end of the day, however, technology selection is a choice made on market conditions, risk, and capital costs—not by the requirement to capture CO₂.

We also wanted to evaluate how technology selection impacts CO₂ capture and footprint. Figure 8 summarizes the CO₂ emissions for the same cases:

Figure 8. CO₂ Emissions by Technology



In Figure 8, the darker bars on the bottom show the total CO₂ emissions for each case without CO₂ capture. The lighter bars on top reflect the parasitic CO₂ generation, when CO₂ capture is installed. As expected, 2e found that CO₂ generation generally increases with the amount of conversion. Delayed coking has a conversion of around 81% of bitumen; EB HCK has a conversion of around 85% of bitumen and SP HCK, about 95%. The hydrogen generation necessary to gain the higher conversion results in more CO₂ generation. However, with gasification, the hydrogen generation for EB HCK is actually lower than with Delayed coking, because the gasification of all the EB HCK pitch is about in balance with the hydrogen and power needs of the complex. For SP HCK with a gasifier, supplemental hydrogen is supplied via natural gas imports through an SMR.

The key, then, to minimizing CO₂ generation is maximizing the product make while minimizing natural gas imports for hydrogen production. Also note that gasification has lower parasitic CO₂ generation.

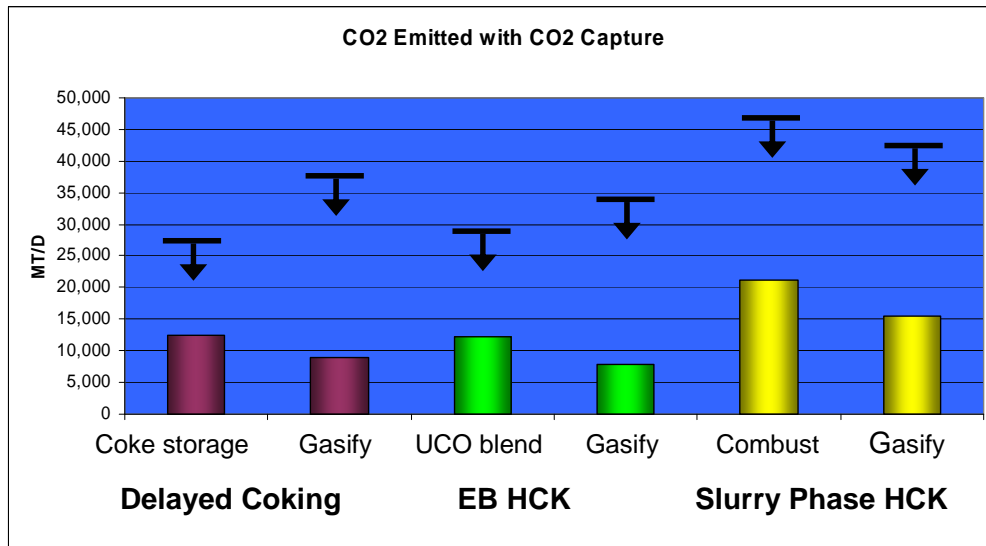
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As shown in Figure 9, for the cases of CO₂ capture, the impact is even more pronounced. As mentioned above, the CO₂ emissions decrease from delayed coking to EB HCK but increase substantially for SP HCK. Similarly, we see a larger reduction in CO₂ emissions for gasification, representing the effectiveness of CO₂ removal with gasification. With gasification, the total CO₂ emitted after capture is lower for all three technologies. While this is not surprising for the SP HCK case because the alternative is combustion, but is surprising for the EB HCK and delayed coking cases. In both cases, a large amount of carbon is eliminated from the carbon balance as explained below:

- Delayed coking – in the storage case, carbon is sequestered in the long term storage of the coke
- EB HCK – in the UCO blend case, carbon is shifted downstream to US refineries

This is largely due to the fact that hydrogen generation with an SMR releases more CO₂ than gasification because the feed side is the only high concentration production. Nearly 38% of the natural gas or fuel gas carbon to an SMR is on the fuel side. While the fuel side could be captured via the flue gas, the source is small enough by itself to be prohibitively expensive for capture, but still large enough to impact overall emissions when compared to a gasifier with integrated CO₂ capture.

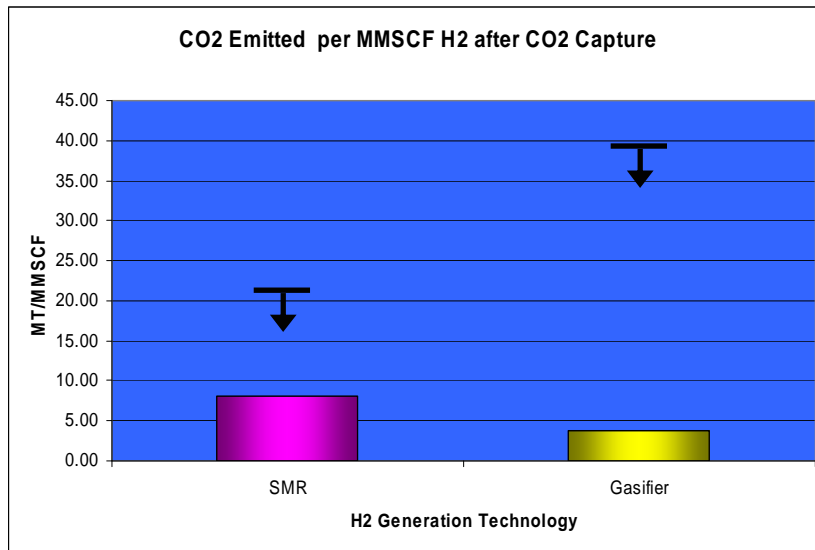
Figure 9. CO₂ Emissions by Technology



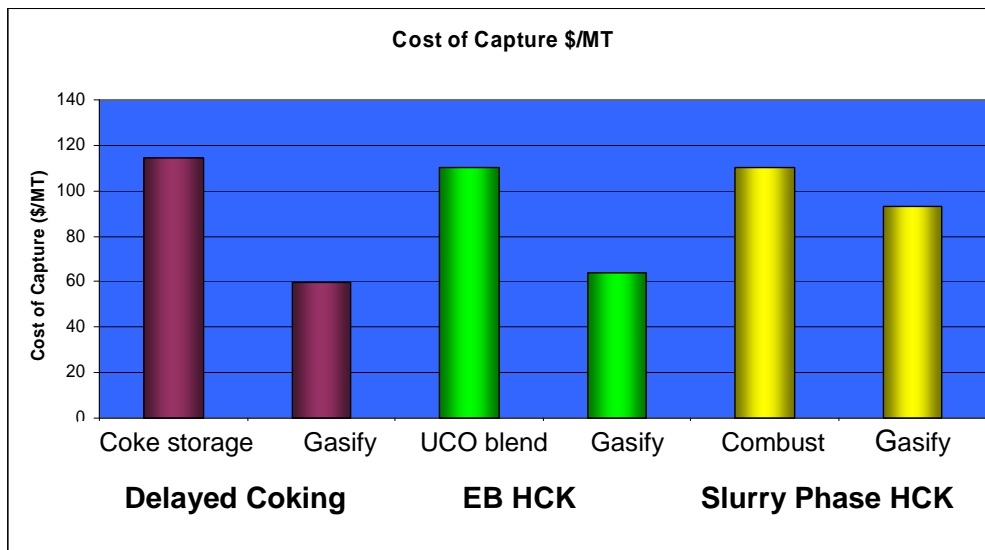
Hydrogen Production

As seen above, the CO₂ emissions related to hydrogen production contribute to the higher CO₂ emissions, especially at higher conversions and higher hydrogen consumption. We compared the CO₂ generation with and without capture for SMR, which is the most common method of hydrogen generation and gasification. Figure 10 shows the CO₂ emissions per MMSCF of hydrogen production for SMR and gasification. The black bars and arrows reflect the CO₂ generations without CO₂ capture.

Figure 10. CO₂ Emissions for Hydrogen Generation



With CO₂ capture, SMR produces twice as much CO₂ as the gasifier for every unit of hydrogen produced. In addition, the capture of CO₂ is much less expensive with gasification as shown in Figure 11 on the following page. This has a direct impact on the improvements we see in Figure 7 for NPV of the gasification cases after incorporating CO₂ capture. Even with a substantial amount of post-combustion capture from the SAGD steam boilers, the overall cost of capturing CO₂ in the gasification cases is much lower due to the significant reduction in capturing CO₂ from the gasifier, which is as low as \$20-30/ MT.

Figure 11. Cost of CO₂ Capture

Conclusions

The conclusions from the economic and CO₂ footprint study for upgrading location and technology selection are as follows:

- Location of upgrader has a minor impact on CO₂ footprint and the capital costs are higher at remote locations for several reasons:
 - Different steam/water system requirements: SAGD production uses high pressure saturated steam produced with poor quality water that is in direct contact with the produced oil. Upgrading or refining produces and uses high quality, superheated, lower pressure steam and is recycled but always kept separate from the oil side, and, therefore, stays much cleaner than the SAGD steam/water system.
 - Different boiler technologies: Due to the differences in the steam requirements and water quality, the boilers used in SAGD are much different than the upgrading/refining side. SAGD boilers are typically once through steam generators (OTSGs) that blow down approximately 25% of the water to maintain wet tubes that help prevent an excessive amount of the contaminants present from fouling the tubes. The boilers on the upgrading/refining side operate much different and produce superheated steam with very little blow down to maximize efficiency.
 - Pitch or coke combustion is costly and generates significant levels of CO₂: Although coke or pitch from the upgrader can be used for SAGD fuel, it is expensive especially

- when CO₂ is captured. Gasification provides a less expensive route to monetize the pitch or coke when the CO₂ is captured, and is almost ideally suited for hydrogen production as opposed to fuel for SAGD, particularly when CO₂ capture is considered.
- Low heat integration potential: Because the produced oil from SAGD must be cooled to remove the co produced water, little opportunity for heat integration exists between the SAGD and production complex.
 - Although Ft. McMurray has high capital structure, difference accentuated by overall capital escalation: Recent capital escalation has increased the cost impact of installing facilities in remote operating environments.
 - Technology Selection is independent of capturing CO₂ – the decisions upgraders face on technology is still a function of market conditions and capital costs and are not impacted by the costs of installing and operating CO₂ capture. CO₂ capture is expensive and reduces the profitability of all the configurations, but does not change the relative ranking of the upgrading technology from an economic consideration.
 - Technology does impact CO₂ emissions
 - The key is minimizing utility imports and maximizing pre-combustion capture: The selection of an upgrading technology will impact total CO₂ emissions with and without capture. Generally, increasing conversion with hydrogen addition increases the CO₂ footprint, but utilization of gasification with CO₂ capture, particularly when the residue production is in balance with the hydrogen and power demands, can dramatically reduce the CO₂ footprint.
 - Gasification provides a mechanism to minimize utility imports and provide a large pre-combustion capture facility
 - New technologies have the potential to improve economics and reduce environmental footprint: Continued development of upgrading technologies, gasification improvements, and carbon capture methodology is required to meet the challenges of the future.
 - Promising opportunities for reducing CO₂ footprint exist through improving efficiencies in SAGD and centralized upgrading infrastructure. The integration of SAGD and upgrading facilities does not provide significant improvement on CO₂ emissions and profitability, therefore AERI is continuing to study ways to improve current operations through efficiency improvements and to quantify the benefits of centralized infrastructure facilities based on the gasification of coke and pitch.