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PTAC CO2 Committee

Design and Cost Estimate for the Collection of CO2 Emissions in the Fort Saskatchewan Area for Use in Enhanced Hydrocarbon Recovery

Executive Summary

This report is the culmination of two years of hard work and effort by the PTAC committee researching CO2 Enhanced Hydrocarbon Recovery. We have achieved our goal of addressing one of the most important topics identified as a barrier to executing enhanced recovery projects in Alberta using CO2 – what is the availability of commercial quantities of CO2 and what is required to create or aggregate a supply? This report examines the technical feasibility and associated costs of aggregating significant volumes of CO2 for use in enhanced oil recovery specifically from the Fort Saskatchewan and surrounding area. To that end, SNC-Lavalin were contracted to:

- Confirm the feasibility of CO2 recovery at the identified sources
- Provide conceptual details of processing and aggregation of
- Generate Class V capital and operating cost estimates (+/- 40%)
- Provide plot plans for the facilities provided at each CO2 source and the central compression facility

This report would not have been possible without the vision, guidance, support and funding of the participating companies and government agencies listed below. The multi-disciplined approach to this project has significantly enhanced the quality of the final report.

Study funding participants:

Air Liquide Canada Inc.
Alberta Employment, Immigration and Industry
Alberta Energy Research Institute (AERI)
ARC Resources Ltd.
ATCO Midstream, ATCO Pipelines, ATCO Power
Devon Canada Corporation
Enbridge Inc.
Enerplus Resources Fund
EPCOR Merchant & Capital LP
Ferus Inc.
Inter Pipeline Fund
Kereco Energy Ltd.
Natural Resources Canada

Pembina Pipeline Corporation
Penn West Petroleum Ltd.
Praxair Canada Inc.
TransCanada Pipelines Ltd

We also acknowledge NW Upgrading Inc. who provided information in kind regarding their planned Upgrader CO_2 supply.

The report and scope of work addresses important and timely issues for Alberta and Canada as concerns over greenhouse gas emissions gain momentum. The conclusions and recommendations will be useful to facilitate discussions regarding CO_2 policy and regulations and potential enhanced hydrocarbon recovery projects. SNC-Lavalin has completed their part of the study with an unbiased and objective viewpoint.

It should be highlighted that since this report will eventually be made public, it was not the intent (or scope of work) of this study to determine a market value or suggest a trading or sale price for CO_2. The study only addresses what would be involved to capture CO_2 from specific sources and aggregate. SNC-Lavalin has provided capital cost estimates for the various facilities examined which highlights the differences between different case scenarios. To facilitate comparison, SNC-Lavalin created a $/Tonne metric which consists of an annualized capital charge and operating cost divided by the volume of CO_2 captured. This metric is useful to compare results within the study, but cannot be used to estimate the value of CO_2.

The nature of this project requires a different mind set than other capital projects. For conventional capital projects, it is the norm to apply a capital charge and/or look at them from a threshold rate of return perspective. For this study an approximate 8% rate of return capital charge was used to calculate the $/Tonne metric. It is perhaps inappropriate to assume that a CO_2 capture project should generate revenue if government regulations force companies to limit emissions. If regulated, CO_2 capture will become a 'cost of business' expense which will need to be compared to each company's specific situation and potential alternatives to meet regulations.

This study highlights capture cost efficiencies by looking for the lowest cost method to effectively capture CO_2 from refinery/upgrader hydrogen production units. SNC-Lavalin has also included a calculation of "net CO_2 after parasitic CO_2 deducted". This is similar to "CO_2 avoided" calculations which account for CO_2 generated in the process of CO_2 capture, and is shown for informational purposes only.

The key conclusions and recommendations listed in the report address the main objectives defined in the project proposal and can be summarized as follows:

- There is at least 10,000 Tonnes per day of CO_2 that could be captured and aggregated in the Fort Saskatchewan area in the near future.
- The total capital estimated to be required to capture 10,000 Tonnes per day would be approximately $400 million dollars.
- The NW Upgrading process is the lowest cost source as it creates a purified CO_2 stream that only requires compression to transport.

- The next lowest cost source are Shell and PetroCanada's hydrogen generation units. The study confirms that very high purity CO2 can be captured from these steam-methane-reformer (SMR) hydrogen plants at an estimated cost range of $100 to $200 million.
- That within an SMR facility, pre-PSA capture is more cost effective compared to post-PSA capture.

The removal of CO2 can be incorporated into existing and new SMR facilities. The comparison of pre-PSA SMR capture processes to post-PSA capture processes was particularly enlightening as the study confirms that pre-PSA process streams are more suitable for CO2 capture. Very high purity CO2 (99.5%) can be achieved without sulphur or other contaminants, which is desired by enhanced oil recovery (EOR) projects. Pre-PSA capture actually enhances the SMR overall process by debottlenecking furnace velocities and enhancing the capacity of the PSA by removal of CO2. Clearly, if SMR operators were motivated to capture CO2, the pre-PSA stream is a viable and potentially beneficial stream to consider. CO2 capture from the post-PSA stream is feasible, but significantly more expensive than pre-PSA mainly because of the lower pressure and therefore more expensive capture process. Different amines are required with post-PSA capture with larger equipment and higher amine heat input for regeneration as well as additional compression.

The differences between SMR pre and post-PSA capture issues highlight the reasons why CO2 capture from flue gas streams are even more expensive. Flue gases from SMR furnaces and other types of boilers and furnaces are more complex due to the hot, low pressure, low purity CO2 flue gases with potential other impurities that must be treated and compressed. CO2 capture from industrial process can be evaluated in priority of capture cost and volume. An important learning from the study is that pre-PSA SMR capture of CO2 can remove approximately 2/3 of total CO2 emissions from the SMR hydrogen unit. The majority of CO2 emissions from an SMR can be captured with available technologies. The remaining CO2 emissions could be captured from the furnace flue gas, but at significantly higher capture cost.

While the study specifically examined the options of capturing and aggregating CO2 based on current or planned facilities, SNC-Lavalin noted that if the objectives of hydrogen generation and CO2 capture are considered together in a new hydrogen facility, the Benfield process or other processes that capture CO2 as part of the hydrogen purification process may be better design choices than SMR. Overall capital and operating costs may be reduced from a study of the combined objective of hydrogen generation with integrated CO2 capture. Further site specific study is also necessary to optimize plant designs and integration into new and existing facilities. It is conceivable that the large heat duty required for regenerating amine could be integrated into co-generation or other energy efficient concepts.

Since neither Shell nor Petro-Canada agreed to participate in this joint study, SNC-Lavalin used representative process data from the SMR plants. As public data for vendor packaged SMR hydrogen plants is readily available, confidence in the study process data is high. Without site specific plant data, the study assumed standalone CO2 capture facilities without any synergies of utilities or heat duty integration. Natural gas was used for fuel and pricing was assumed for power and boiler feed water. It is felt that with site specific plant knowledge lower capital and operating cost could be achieved. Assumptions in this study are considered appropriate for the SNC-Lavalin Class V (+/- 40%) cost estimating certainty. Should either of these firms wish to further explore the concepts of this study, we would be pleased to have them provide their information so that SNC can more accurately define these costs.

Pipeline design to specific EOR reservoirs was not included in the study scope of work mainly to reduce the study scope and subsequent cost. CO2 transport over long distances for EOR has been demonstrated in Texas and Saskatchewan. This study assumed compression and associated costs was required to achieve 2700 psig as a final pressure, similar to the Weyburn, Saskatchewan EOR project. If an Alberta CO2 pipeline network is to be constructed from the Fort Saskatchewan area, future analysis will clarify the optimum pressure. Optimum transport pressure will be a balance of volume, compression, pipeline locations and construction timing. It will also depend on who owns and operates the initial compression versus pipeline booster compression. This study concludes that there are economies of scale in CO2 compression which would support the use of larger compressor designs.

Ultimately it is hoped that this study will facilitate the discussion of CO2 capture and advance the science and knowledge of CO2 capture for EOR. Industry discussion and debate of CO2 capture design to date has either been kept confidential or not fully disclosed. As SNC-Lavalin’s work has shown, there may be significant advantages and cost efficiencies achieved if CO2 capture is considered as a component of hydrogen generation. The PTAC CO2 committee for this study believes this report provides an important step in advancing industry knowledge of CO2 capture and should be the catalyst for many interesting discussions.