CO_2 Enhanced Hydrocarbon Recovery: Incremental Recovery and Associated CO_2 Storage Potential in Alberta

Summary Report

December 2009

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Nomenclature

A	Area
API	American Petroleum Institute
ARC	Alberta Research Council
bbl	barrel
BHA	Bottom Hole Assembly
BHL	Beaverhill Lake
BHP	Bottom Hole Pressure
CBL	Cement Bond Log
CDMA	Conglomerate
CIL	Cement Integrity Log
CMG	Computer Modelling Group
CO_2	Carbon Dioxide
CCE	Constant Composition Expansion
COMP	Component
cp	CentiPoise (measure of viscosity; same as mPa.s)
D	Darcy (permeability unit)
d	Day
e3m3, e^3m^3	Thousands of cubic meters
e6m3, e^6m^3	Millions of cubic meters
ECLIPSE	Schlumberger simulator
EOR	Enhanced Oil Recovery
EOS	Equation of State
ERCB	Energy Resources Conservation Board
ESP	Electrical Submersible Pump
FVF	Formation Volume Factor
GEM	Computer Modelling Group Compositional Simulator
GOR	Gas-Oil-Ratio
ha	hectar
HC	Hydrocarbon
HCM	Hydrocarbon Miscible
HCMF	Hydrocarbon Miscible Flood
HCPV	Hydrocarbon Pore Volume (reservoir volume occupied by hydrocarbon)
HZ	Horizontal
IG, ig	Gas injection well
IMEX	Computer Modelling Group Black Oil Simulator
IW, iw	Water injection well
K,k	Permeability
kh	Permeability-thickness product
k_g	Permeability to gas
k_o	Permeability to oil
k_r	Relative Permeability
k_{rg}	Relative Permeability to gas
k_{ro}	Relative Permeability to oil
k_{rog}	Relative Permeability to oil in the presence of gas

k_{row}	Relative Permeability to oil in the presence of water
k_{rw}	Relative Permeability to water
k_w	Water Permeability
kPa	Kilo Pascal
LSD	Legal Sub Division
mD	milli Darcy
MM	Million
MMBOE	Million Barrel Oil Equivalent
MPa	Mega Pascal
mPa.s	Milli Pascal second (viscosity unit; same as centipoise)
mscf	thousands of standard cubic feet
mss	Meters sub sea
m^3	Cubic meter
NE	North-east
NW	North-west
NPCU	North Pembina Cardium Unit
NTG	Net-to-Gross Ratio
NTZ	No thief zone
OOIP	Original Oil in Place (stock tank volume)
OWC	Oil-water-contact
P_b	Bubble point pressure
P_c	Critical pressure
P_d	Dew point pressure
PCU	Pembina Cardium Unit
Phi-h	Porosity-thickness product
PV	Pore Volume
PVT	Pressure Volume Temperature relationship (used in reference to phase behaviour studies)
$rm^3(RM^3)$	Cubic meter, reservoir conditions (pressure and temperature of reservoir)
RF	Recovery factor
ΔRF	Incremental recovery factor
RFP	Request for proposal
ROW	Right of Way
RTA	Rate transient analysis
SCADA	Supervisory Control and Data Acquisition
SCVL	Surface Casing Vent Leaks
SF	Solvent Flood
SFA	Solvent Flood Area
SE	South-east
$sm^3(SM^3)$	Cubic meter, standard conditions (15.6 ^oC and 101.3 kPa)
STB	Stock tank Barrels
SW	South-west
S_g	Gas saturation (fraction)
S_l	Liquid saturation
S_w	Water saturation (fraction)
S_{wi}	Initial water saturation (fraction)
t	tonne
T_c	Critical temperature

TZ	Thief Zone
UWI	Unique Well Identifier
VRR	Voidage Replacement Ratio
VSD	Variable Speed Drive
WAG	Water-Alternating-Gas
WF	Waterflood
WFA	Waterflood Area
W/G	Water-gas
WinProp	Computer Modelling Group phase behaviour software
WOR	Water-oil-ratio
WC (WCUT)	Water cut

1.0 EXECUTIVE SUMMARY

This is a summary of a more detailed report provided to the Alberta Department of Energy. It contains a high level overview of that report.

Albertans need a better understanding of the potential of CO_2 Enhanced Oil Recovery (EOR) in Alberta, along with its limitations. The Alberta Energy Research Institute (AERI) and the Alberta Department of Energy (ADOE) contracted the Alberta Research Council (ARC) to complete a detailed reservoir and development analysis to quantify the potential for incremental oil recovery and associated CO_2 capture and storage for five horizontal miscible CO_2 flood target pool types (prototypes) in Alberta. The detailed results from the five prototype pools were extrapolated to some 35 analogue pools and areas to provide an estimate of CO_2 enhanced oil recovery potential, CO_2 requirement, and associated CO_2 storage potential for these pool types. The ultimate objective of this project was to provide critical technical information and data to accelerate the pace of EOR and Carbon Capture and Storage (CCS) demonstration and field projects in Alberta.

Together, the prototype and analogue pools studied have original-oil-in-place of 2.523 billion cubic meters (15.869 billion barrels) and represent approximately 30% of Alberta's light-medium oil resource. For purposes of this study, the specific pool areas studied were high graded to include practical floodable areas most likely to have EOR applied (Table ES-1). The high graded areas had original-oil-in-place of 1.841 billion cubic meters (11.578 billion barrels).

The target pool types were selected for study in consultation with ADOE and AERI. They were: Beaverhill Lake waterflooded pools, Beaverhill Lake hydrocarbon miscible flooded pools, Pembina Cardium pools with thief zone, Pembina Cardium pools without thief zone, and Redwater D-3. Table ES-1 provides a summary of CO_2 requirements and oil production for EOR operations for the prototypes and analogues studied.

Table ES-1: CO_2 EOR Requirement and Storage for Prototypes and Analogues – No Risk Factor

Prototypes and Analogues	OOIP	Predicted CO_2 Oil Recovery	CO_2 Injected	CO_2 Purchased	CO_2 Utilization		
	10^3m^3	10^3m^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
BHL Prototypes and Analogues (WFA & SFA)	752,608	55,605	360	99.2	6.48	1.78	5.4
D-2/D-3 Prototype and Analogues	601,853	44,360	277	82.0	6.24	1.85	5.6
Cardium Prototypes and Analogues (Thief zone and non-thief zone)	486,216	71,400	296	71.9	4.15	1.01	3.1
Total	1,840,677	171,365	933	253	5.44	1.48	4.5

This study provides new insight into EOR potential in Alberta. This methodology is an improvement on earlier studies, which were based on high-level reservoir parameter screening or on element of symmetry simulations, rather than on detailed reservoir technical evaluation. **It is important to note that a detailed economics assessment was not a deliverable of the project.** Economic data is not provided in this summary report. Moreover, this assessment did not include the costs of CO_2 delivered to the site at the required injection pressure. The study provided the economic indicators from its development plans in sufficient detail that the ADOE could begin evaluating the economic and crown royalty impact of CO_2 EOR in Alberta. Individual pool results vary based on amount of CO_2 injected and EOR recovery factor (Table ES-2).

Table ES-2: CO_2 EOR Prototypes-Development Plan Summary

		Cardium	Cardium	BHL	BHL	D-3	Total
		TZ	NTZ	WFA	SFA	Redwater	
OOIP	**e^6m^3**	66.9	59.7	43.5	149.4	226.7	546.3
Oil Recovery	**e^6m^3**	11.2	7.7	9.5	4.5	12.8	45.7
Oil Recovery	**10^6 Bbl**	70.5	48.3	59.7	28.5	80.4	287.3
		16.7%	12.8%	21.8%	3.0%	5.6%	8.4%
HCMS Recovery	**e^6m^3**				1,231		
CO_2 Injection	**Mt**	36.9	68.5	39.9	45.2	62.0	252.5
% HCPV		50.3%	99.1%	79.3%	40.5%	100.1%	
CO_2 Purchased	**Mt**	10.4	13.9	12.5	10.3	17.5	64.6
		14.2%	20.1%	24.8%	9.3%	28.2%	
Gross Utilization	**t/m^3**	3.29	8.93	4.21	9.96	4.85	
Net Utilization	**t/m^3**	0.93	1.81	1.31	2.28	1.37	
Gross Utilization	**mcf/Bbl**	9.97	27.07	12.76	30.20	14.72	
Net Utilization	**mcf/Bbl**	2.82	5.50	3.98	6.91	4.15	

Based on predicted incremental recovery, CO_2 storage risk and processing rate considerations, development of the BHL pools should take priority over the Pembina prototypes. Predicted incremental enhanced oil recovery from the two BHL prototypes totals 14 million m^3 (waterflood prototype yields 9.5 million m^3; solvent flood prototype yields 4.5 million m^3) or 88 million bbl. A total of 25.8 Mt of CO_2 would be required to be purchased for the BHL prototypes, essentially all of which would eventually remain in the BHL prototype reservoirs. The Pembina prototypes, though estimated to give higher total incremental oil recovery than the BHL prototypes (18.9 million m^3; 118.9 million bbl), will require a much longer time frame to produce (75 or more years compared to 50 years for the BHL prototypes) because of the Pembina reservoir's low processing rate compared to the BHL prototypes. The

Pembina prototypes would require 24.3 Mt of purchased CO_2, essentially all of which would eventually remain in the Pembina prototype reservoirs. The Pembina projects require significant unproven technology to increase processing rate and contain the CO_2 in the flood target. Furthermore, practical floodable OOIP, particularly in the Cardium, is much lower than ERCB OOIP data. Only 31% of the total Pembina Cardium OOIP was predicted to be amenable to CO_2 EOR. The D3 prototype (Redwater) is predicted to give the least incremental oil recovery of the prototypes studied, 12.8 million m^3 (80.4 million bbl), primarily because it operates at lower pressure and is not fully miscible. In addition, the remaining oil target is lower because of the very effective water drive. However, detailed analysis of the Redwater reef on a well by well basis and using modern seismic may allow a more efficient vertical displacement flood in portions of the reef and increase the EOR recovery factor. The Redwater prototype would require purchase of 17.5 Mt of CO_2, essentially all of which would eventually remain in the Redwater prototype reservoir. The Redwater reservoir is close to CO_2 sources in the Fort Saskatchewan area and would require less CO_2 transportation infrastructure development than the other prototypes.

The total potential CO_2 EOR for all the prototypes and analogues studied is projected to be 171.4 million m^3 (1.08 billion bbl); this would require purchase of 253 million tonne of CO_2, essentially all of which would eventually be stored in the target reservoirs.

Development plans were generated only for the five prototypes studied. A spreadsheet-based model was utilized to schedule development by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns. It was assumed that CO_2 was delivered at the field gate at the pressure required.

From the development plans, CO_2 EOR potential of the five prototype pools is 45.7 million cubic meter (287.3 million barrel). Purchased CO_2 requirement is projected to be 64.6 million tonne for an average net utilization of 1.41 t/m^3 (4.27 mcf/bbl). Individual pool results vary based on amount of CO_2 injected, EOR recovery factor and whether full produced CO_2 stream recycle or separation is considered. For instance, recovery of hydrocarbon miscible solvent from produced CO_2 will occur in BHL SFA pools. Detailed development plans were not prepared for the analogues.

This project began a new chapter in the assessment of EOR potential in Alberta. Nevertheless, further work still needs to be done. The original AERI RFP identified 17 different pool types for assessment; ultimately only five were assessed. There remain the other 12 horizontal miscible pool types, as well as vertical and immiscible targets to consider. Furthermore, the five simulations produced in this report could benefit from more refinement, especially more sensitivity analysis. This study was restricted to the field characteristics for CO_2 flooding and did not consider the proximity to suitable CO_2 sources or the cost to deliver CO_2 to the field. It would be useful to build on this work by evaluating potential sources and estimate transportation costs to deliver the CO_2 to the fields so economics can be run to quantify the size of the “gap” between the cost to capture, purify, compress and transport the CO_2 and its value as a solvent.

In summary, this report provides assessment of the target pools in Alberta that would benefit the most from EOR. This provides a technical baseline for policy discussions in the Government of Alberta. However, far from concluding investigations in this area, this report demonstrates that considerable work still needs to be undertaken to better understand the economic, environmental and policy options for Alberta.

2.0 INTRODUCTION

Partly in response to the recommendations of the Petroleum Technology Alliance Canada (PTAC) study *Ramping Up Recovery* and growing interest in CO_2 Enhanced Oil Recovery in Alberta, the Alberta Energy Research Institute (AERI) funded this project to quantify the potential incremental recovery and associated CO_2 storage potential in Alberta. This report provides insights into further research projects for AERI (now Alberta Innovates – Energy and Environment Solutions.

The Alberta Research Council (ARC) led the project and managed the project team. The multi-disciplinary team assembled for this project draws staff from the ARC and seven contractors, with expertise in numerical modelling, reservoir engineering, carbon capture and storage, field project design, implementation, monitoring, interpretation, and project management. The project was divided into three tasks. Through Task 1 (identification of geological prototypes in Alberta for CO_2 enhanced recovery), Task 2 (numerical modelling of the target prototypes) and Task 3 (production of development plans), the team has been able to quantify the potential for increased oil production and associated CO_2 storage in the target geologic formations. Furthermore, through extrapolation to similar formations and experiences from other jurisdictions, the team estimates the total oil recovery and associated CO_2 storage potential for CO_2 enhanced oil recovery for some thirty-five pools and areas that represent approximately 30% of Alberta's conventional oil resource.

In summary, this report provides assessment of the target geologic formations in Alberta that would benefit the most from CO_2 enhanced oil recovery. The report demonstrates that considerable work still needs to be undertaken to better understand the economic, environmental and policy options for Alberta.

2.1 BACKGROUND OF PROJECT

In response to a Request for Proposal (RFP) issued by AERI (Appendix 3), ARC was awarded the contract in September 2007. As the project leader and integrator, ARC established a methodology and work plan to undertake this study. Previous estimates of CO_2 Capture and Storage (CCS) potential in Alberta have been based on reservoir screening criteria, rather than on detailed reservoir technical and economic evaluation. The objective of this project was to complete a detailed reservoir and development analysis of five representative pools, in order to quantify the potential for incremental oil recovery and associated CCS potential in Alberta. The project methodology predicts the incremental Enhanced Oil Recovery (EOR) and CO_2 storage in each of the five prototype pools and extrapolates the findings to some thirty-five analogue pools and areas amenable to CO_2 EOR. Development plans provided data to allow the ADOE to evaluate the economic and crown royalty impact of the CO_2 EOR. The ultimate objective of this project was to provide critical technical information and data to accelerate the pace of CCS demonstration and field projects in Alberta.

ARC acted as the Principal Contractor for the study. Overall project management was provided by ARC. Computer Modelling Group (CMG), SNC-Lavalin Inc. (SNC-Lavalin or SLI), Sproule Associates Limited (Sproule), Divestco, Silvertip Ventures and Vikor Energy Inc. (Vikor) were subcontractors to ARC. These organizations were well positioned to undertake the proposed project. As detailed below, these organizations have extensive in-house expertise in numerical modelling, reservoir engineering, carbon capture and storage, field project design, implementation, monitoring, and interpretation. These companies have been involved in developing and implementing enhanced oil recovery technologies, in some cases for more than 40 years.

In order to provide all the skills necessary to deliver the project, the lead organizations partnered with third parties to provide additional expertise in geological and development areas. For example, in Task 1, ARC complemented its expertise with that of The Green Six Ltd (Art Danielson) for reservoir assessment and development planning activities, and with Sproule Associates (Chris Galas) for validating the results of this analysis. Static reservoir modelling expertise was provided through partnering with Divestco, Inc. and engaging the services of experienced geologists David Shaw and Peter Dankers to provide geological reservoir modelling support. Task 2 was a cooperative effort between ARC, CMG and Sproule. Task 3 was led by ARC with contributions from SNC Lavalin, Silvertip Ventures, Vikor Energy and Sproule. At the request of AERI, Derril Stephenson of Vikor Energy Inc. was engaged to provide ongoing guidance and review during the course of the project to ensure that the needs of ADOE were met. In addition, Derril Stephenson was also engaged by ARC to assist with preparation and evaluation of development scenarios in Task 3.

Within the scope of the proposal, Task 1 identified 5 prototype reservoirs, selected areas for simulation, and determined analogue groupings. In Tasks 2 and 3, the project team focused on the 5 prototypes that represent 34% of the original-oil-in-place for the light and medium oil pools of Alberta (ERCB 2006). These 5 prototypes included two Beaver Hill Lake, two Cardium and one D-3 pool from the prospects listed in Table 1A of the RFP. The results were then extrapolated to approximately thirty-five oil pools and areas (of the 200 oil pools listed in Tables 1A, 1B, and 1C of the RFP) where extrapolation was deemed appropriate and valid.

2. 2 PROJECT OBJECTIVES AND OVERALL APPROACH

The objectives of the study were:

- To identify 5 prototype Alberta reservoirs (out of a list of 219 in Tables 1A, 1B and 1C of the RFP)
- To study 5 representative prototype Alberta oil pools in detail to predict the incremental oil recovery and CO_2 storage in the pools
- To develop a methodology to appropriately extrapolate the findings to other pools amenable to CO_2 EOR

- To provide development plans for selected fields and associated economic indicators in sufficient detail that Alberta Department of Energy could assess the economics of CO_2 EOR in the province.

Based on the results of the assessment, the ADOE will be able to evaluate the economic and crown royalty impact of the CO_2 EOR. The ultimate objective of this project was to provide critical technical information and data to accelerate the pace of CCS demonstration and field projects in Alberta.

2.3 TASK DEFINITION

As formulated, the project comprised of three main tasks.

- **Task 1** involved an iterative process to identify 5 prototype pools from the original 17 in the proposal, and clustering of analogue groupings from the list of pools provided by AERI in the RFP. The process included initial clustering and evaluation of cluster characteristics to reduce the number of potential prototypes. Five prototypes were selected for more detailed evaluation in Task 2. The pools were selected to ensure a high level of representation and meaningful extrapolation to the larger group pools specified in the RFP. As per the RFP, Beaver Hill Lake, Cardium and Redwater prototypes (representing approximately 34% of the provincial OOIP) were selected for the first 5 prototypes. Specific areas of the pools from the prototypes were identified to simulate in Task 2. Some preliminary examination of development options were undertaken to ensure appropriate integration of Tasks 1, 2 and 3.

- **Task 2** involved the further evaluation of the 5 principal prototype pools selected from Task 1. Numerical modelling of selected areas (sector models) of the five prototype pools was undertaken. The selected areas were history matched, so that a base case prediction of ultimate recovery could be made. Then additional predictions of recovery were made for CO_2 injection. It was planned that the remaining 12 prototypes would be evaluated using results of sensitivity tests conducted in the 5 simulations as well as correlations that had been benchmarked against actual field data and available simulation predictions.

- **Task 3** involved preparation of generic development plans where economic factors and policy elements could be considered and evaluated. Since a wide range of reservoir types and injection strategies were considered, the scope of options for reservoir performance was large, and there was considerable variation in facilities costs and many different cases that could be contemplated. It was not feasible to complete a detailed cost analysis for all cases. Thus, generic development plans were generated.

In order to be able to extrapolate the results of the Task 2 simulations to the full prototype pools and eventually to analogue pools, the effect of the following were considered in the numerical simulations:

- Reservoir characteristics;
- CO_2 injection process (miscible, variations of WAG etc.);
- Development strategies (infill wells, horizontals, patterns, process);
- Process operating conditions (pressure, flow rates); and
- Simulation parameters (relative permeability).

The results of the study of the pools evaluated in Task 2 were used for calibration of correlations, which were then used with engineering judgement to extrapolate the results for miscible flooding field wide to thirty-five analogue pools and areas.

The approach for Task 3 was to develop and utilize factored unit costs for various approaches (e.g. CO_2 recycle with separation of hydrocarbons gases vs. no separation on $/mcf, well costs, pipeline costs, operating costs). The unit cost factors together with output from numerical simulations of prototypes and the extrapolation of performance characteristics to analogue reservoirs in Task 2, provided input to assessment of development plan scenarios for a broad range of reservoir types. A spreadsheet-based model (Pattern Development Model) developed by Vikor (Derril Stephenson) that schedules development by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns was utilized for this task (See Appendix 1). The field development plans considered:

- CO_2 injection strategies and timing of initiation of new well patterns based on recycle volumes available for various scenarios;
- Use of new and existing infrastructure such as wells, gathering systems, treatment facilities, compressors;
- Capital and operating cost estimates for the surface facilities and operation. Capital expenditure profile consistent with development plan;
- Energy requirements and emissions from the operation;
- Conceptual commercial scale operation with cost estimate accuracy in the +/- 40% range.
- Estimates of the volume of CO_2 sequestered in the reservoir at the end of the production.

At this time the cost estimates remain confidential to the prototype operators and the Alberta Department of Energy.

3.0 IDENTIFICATION OF PROTOTYPES AND ANALOGUE

3.1 SELECTION OF PROTOTYPES

The following prototypes and priorities for simulation were identified:

Pool type	**Prototype pool**	**Operator**	**Simulation by**	**Back-up**
BHL HCMF	Swan Hills	Devon	CMG	Judy Creek
BHL waterflood	Judy Creek	Pengrowth	ARC	Carson Creek North
D3	Redwater	ARC Resources	ARC	-
Cardium –thief zone	Pembina NPCU	ARC Resources	CMG	-
Cardium – no thief zone	Pembina “A”	Penn West	ARC	-

Note: The Redwater D-3 pool was substituted for the BHL Platform on Dec. 3, 2007 at the request of the ADOE.

ARC and Divestco, in collaboration with other team partners, undertook detailed in-depth geological studies/reviews (regional as well as specific pools and prospective areas) along with their respective performance. Study areas were selected based on their representative characteristics for major parts of the EOR targets. ARC proceeded to build simulation models but discovered that the two BHL study areas had many similarities and together they did not cover the full range of the prospective CO_2-EOR regions. ARC also made a similar determination about the two Cardium study areas selected. However, none of the types of EOR targets inadequately covered by these selections were considered critical in terms of ‘size of the prize’ or expected variation in EOR response to merit extending the study. Our approach was to use a parametric sensitivity study in Task II along with our collective past experience/judgement to cover as many situations as technically justified. The relevant data were shared with the teams involved with Task 2 to enable them to proceed with their work.

Past EOR related activities in the five prototype areas were also studied to develop, test, and validate extrapolation methodology, and identify scenarios requiring simulation in Task 2.

3.2 SELECTION OF SIMULATION AREAS

Pools with a horizontal displacement mechanism were estimated to have about 60% of the OOIP of the pools with CO_2 EOR potential. Therefore, when the number of prototypes to be studied initially was reduced, five pools representative of the largest potential were selected.

3.2.1 Cardium Formation

The Cardium formation has about 24% of the floodable OOIP of the pools with horizontal displacement mechanism CO_2 EOR potential. The Pembina Cardium pool is by far the largest conventional oil pool in Alberta. It contains areas with high permeability zones (thief zones) where flow must be controlled to achieve reasonable conformance in the reservoir and low productivity areas where processing time is very deleterious to EOR economics. It was decided to complete two studies on the Cardium, one with a thief zone and one with no thief zone.

3.2.1.1 Cardium Thief Zone

The best area of Pembina Cardium is in the North Pembina Cardium Unit #1; ARC Resources is contemplating a pilot in this region and agreed to assist with the study.

3.2.1.2 Cardium No Thief Zone

Penn West has been operating a pilot in the Pembina Cardium "A" Lease and significant geological and history match work had been done on the area. This area contains conglomerate but it does not have high permeability so it was decided to build on this work. Penn West agreed to assist with the study.

3.2.2 Beaverhill Lake Formation (BHL)

The BHL formation has about 35% of the floodable OOIP of the pools with horizontal displacement mechanism CO_2 EOR potential. Most of the best parts of the BHL pools have had hydrocarbon miscible floods so a CO_2 flood would be "quaternary" not "tertiary" and could recover additional hydrocarbon miscible solvent (HCMS). Some of the areas in the BHL that have not been solvent flooded are the best candidates for CO_2 EOR. It was decided to complete two studies on the BHL one in a Solvent Flood Area (SFA) and one in a Waterflood Area (WFA).

3.2.2.1 BHL SFA

The Swan Hills BHL pool is the second largest conventional oil pool in Alberta. Devon Canada has completed a CO_2 pilot in an upper layer of a pattern that had high HCMS injection. Devon agreed to assist with the study using a simulation area that encompassed the pilot area.

3.2.2.2 BHL WFA

Pengrowth agreed to assist with the study using an area of Judy Creek BHL. The simulation area was developed for Judy Creek, but as most of Judy Creek BHL pool has already been solvent flooded it was decided to use Swan Hills WFA as the prototype as more geological data was available on Swan Hills.

Pengrowth also operates the Judy Creek Gas Conservation plant which services most of the large pools in the area. They provided input to the design and costs of the recycle system.

3.2.3 D-3 & D-2

The D-3 formation has about 5% and the D-2 formation has about 6% of the floodable OOIP of the pools with horizontal displacement mechanism CO_2 EOR potential. Redwater D-3 pool is the third largest conventional oil pool and is strategically located close to the "Heartland". It sits on a huge saline aquifer with CO_2 storage potential. Significant geological and history match work had been done on the pool and ARC Resources is operating a pilot in this pool and agreed to assist with the study.

3.3 ANALOGUE GROUPINGS

The results of sector model simulation and prototype development plans were used to extrapolate results to analogue pools. For each of the prototypes studied in the numerical modelling task, a number of analogue pools were selected for extrapolation of results as outlined in the table below.

Prototype Analogues

Pool type	Prototype pool	Analogues
BHL HCMF	Swan Hills	Swan Hills, South Swan Hillls, Judy Creek A, Judy Creek 'B', Virginia Hills, Goose River, Kaybob
BHL waterflood	Judy Creek	Carson Creek North, Snipe Lake
D3	Redwater	Fenn Big Valley, Sturgeon Lake South, Morinville, Bonnie Glen, Meekwap, West Drumheller
Cardium –thief zone	Pembina NPCU	Cyn-Pem Cardium A, Cyn-Pem Cardium D, Berrymoor, Bear Lake
Cardium – no thief zone	Pembina "A" Lease	Ferrier, Carrot Creek

Since the performance of the pools (history in terms of oil rate and water-oil ratio) is very similar for these pools and the main EOR target is residual oil, it is surmised that empirical methods based on similarity principles would provide reasonable estimates of performance for various analogous pools. Results based on reservoir simulation for the prototype pool were used to develop the desired empirical correlations. The analogue results are in section 5.3 of this report.

4.0 NUMERICAL MODELING OF PROTOTYPES

4.1 PEMBINA CARDIUM WITH CONGLOMERATE PROTOTYPE

The North Pembina Cardium Unit 1 (NPCU) operated by ARC Resources was chosen as the simulation prototype for Pembina Cardium with Conglomerate. A sector approximately 2 sections in area, encompassing wells in Sections 2, 3, 10, and 11 of Township 49, Range 8, W5 was selected for simulation. The geological model was provided by ARC Resources and refined by Divestco. The numerical modeling was carried out by Computer Modelling Group.

4.1.1 Geological Model

The Pembina Cardium pool is the largest conventional oil reservoir in Western Canada with an estimated original oil-in-place of approximately 1.2 billion cubic meters (7.8 billion bbl) (Ross Smith Energy Group Ltd, 2006; Krause et al, 1994). The pool covers an area of 700,000 acres with about 5,900 wells (Figure 4.1.1.1).

The pool is a very large stratigraphic trap, and neither edge or bottom water nor a gas cap is present. It was discovered by Mobil Oil Canada in 1953, and has been extensively water-flooded for several decades.

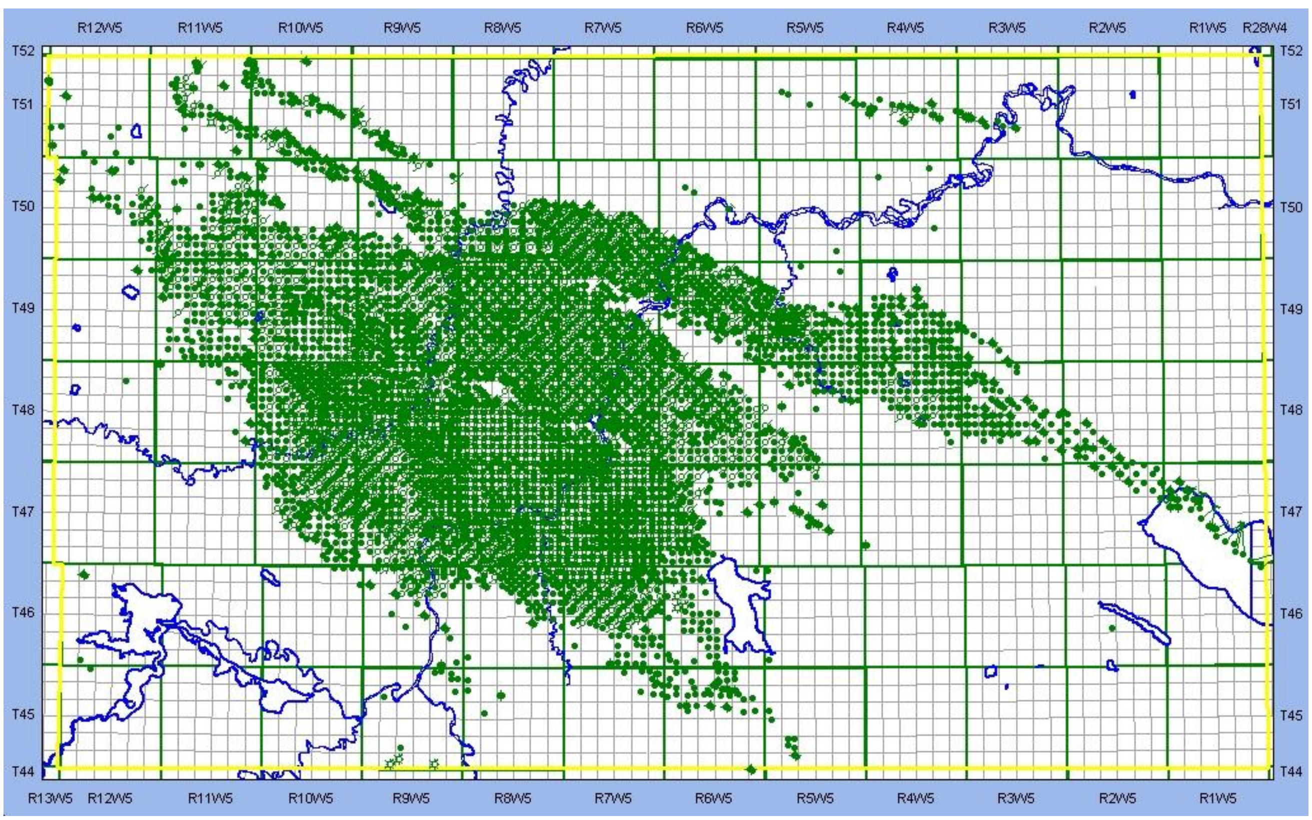


Figure 4.1.1.1: Location and distribution of oil wells in the Pembina Cardium Pool. Source: Divestco Geovista database.

The North Pembina Cardium Unit No. 1 (NPCU-1), currently operated by ARC Resources Ltd., is one of the most attractive candidates for CO_2 injection in the Cardium Formation. A geological model of NPCU-1 was constructed based on geological tops of the Cardium Conglomerate, 5/6 Sand, 4 Sand and 3 Sand supplied by ARC Resources Ltd. and core analysis data from Divestco's Geovista database. A suite of gross thickness and net pay thickness maps created by ARC Resources from core and log data were used for quality-control of the completed model.

The reservoir quality of the Cardium Formation varies considerably and can be related to the environment in which the sediments were deposited. Conglomerates that were reworked by waves or currents in a shoreface setting have better porosity and permeability values than conglomerates formed in a fluvial setting. Shoreface conglomerates occur to the east of fluvial-influenced conglomerates.

Fractures, vertical barriers to fluid flow and the extent to which the conglomerate acts as a thief zone play a major role in Cardium reservoir performance. The orientation of fractures is well established to be SW-NE but their exact location in the subsurface is difficult to ascertain.

The orientation of the geological model area is northeast-southwest, parallel to the regional fracture trend. Cells with dimensions of 25 m x 25 m x 30 cm oriented parallel to the model boundaries were used to construct the model. Geological tops of the Cardium Conglomerate, 5/6 Sand, 4 Sand and 3 Sand supplied by ARC Resources Ltd. were used to construct the structural-stratigraphic framework of the model. Core coverage of the NPCU-1 unit is excellent, and porosity and permeability values downloaded from Divestco's Geovista database were used to construct the rock property model (porosity and maximum horizontal permeability). The model area contains 69 X 86 X 241 cells - the high degree of vertical resolution was used to capture vertical variations in reservoir properties that will affect conformance in the reservoir. The model was exported in RESCUE format for numerical simulation studies.

4.1.2 Numerical Model

The geological Model built using the "Earthvision" software package was imported into the Computer Modelling Group's (CMG) "Builder" simulation pre-processer. Some quality control checks were carried out to confirm that the basic structure of the model and respective position of different geological layers aligned both in the Builder and the Earthvision model.

In the geological model there were 40 layers to represent 4 geological layers, namely "CDMA" (conglomerate), "5 & 6 sand", "4 sand" and "3 sand". This model has 231200 grid blocks. Up-layering was used to reduce the total number of layers in the simulation model to 14. The correspondence between the simulation model layers and the geological layers is shown in Table 4.1.2.1. Figure 4.1.2.1 compares the geologic and simulation models. This numerical model after up-layering has 80920 grid blocks.

Table 4.1.2.1: Layers in Simulation Model

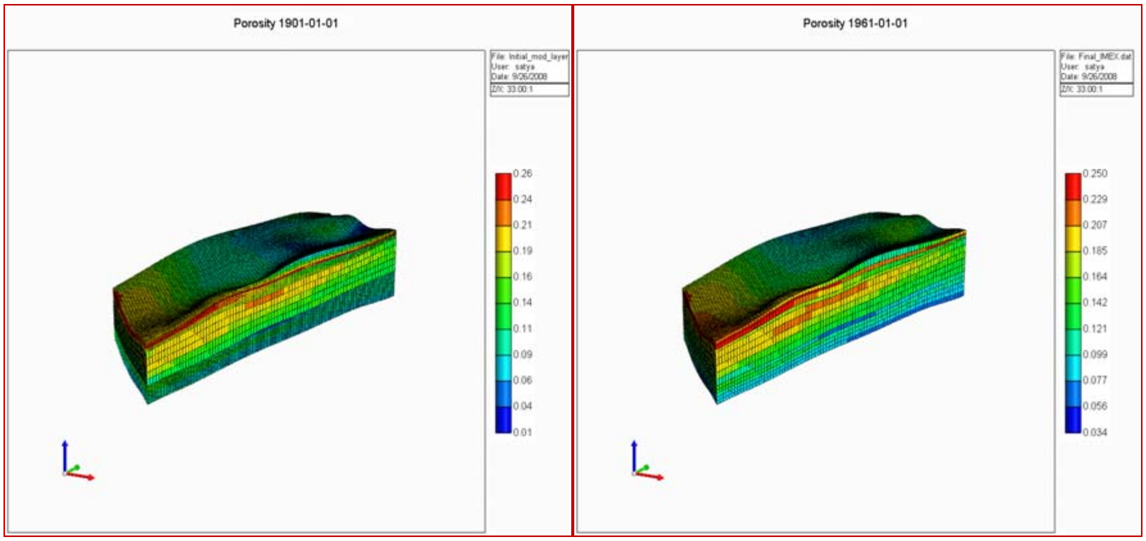
Geologic Layer	Simulation Layer
CDMA (conglomerate)	1
	2
5&6 sand	3
	4
4 sand	5
	6
	7
	8
	9
3 sand	10
	11
	12
	13
	14

The only reservoir properties included in the geological model were porosity, vertical permeability and horizontal permeability. The vertical permeability in the geological model had high values close to the values of the horizontal permeability. Based on other studies of the Pembina field, the vertical permeability was set to 1/10th of the horizontal permeability.

In the area modeled there are a total of 16 wells, four of which have been converted to water injectors at different times. There was also some gas injection into well 06-11-049-08 W5 prior to its conversion to water injection. Table 4.1.2.2 lists the well identifiers and well locations. The injection wells are aligned in a NE/SW direction, with two rows of production wells parallel to the line of injection wells. This constitutes a line drive pattern. The orientation of the pattern is parallel to the preferred fracture direction in this part of the Western Sedimentary Basin.

Historical production and injection data were imported into the model to provide rate controls on the wells as well as for creation of field history files. Petrophysical and fluid properties provided by ARC Resources were incorporated into the model. The average value of petrophysical properties on a layer by layer basis is shown in Table 4.1.2.3.

The well logs indicate that there are barriers between the conglomerate and the 5&6 sand and also between the 4 sand and the 3 sand. In the model this was ensured by setting the transmissibility between the respective sands to zero. All of the wells have been hydraulically fractured multiple times, so during modeling they were open in all layers. On injection, it was expected that the fractures would propagate because of the high injection pressures. This was incorporated into the model through the use of pressure dependent permeability multipliers.



40 Layers 14 Layers

Figure 4.1.2.1: Comparison of the geological model (40 layers) with the upscaled numerical model (14 layers)

Table 4.1.2.2: Wells included in Simulation Area of NPCU				
Injectors	6-11-49-8W5	4-11-49-8W5	16-03-49-8W5	10-03-49-8W5
Producers	1-11-49-8W5	2-11-49-8W5	5-11-49-8W5	12-11-49-8W5
	2-10-49-8W5	8-10-49-8W5	8-10-49-8W5	12-02-49-8W5
	13-02-49-8W5	14-02-49-8W5	8-03-49-8W5	9-03-49-8W5
Pseudo-injectors	6-02-49-8W5	16-04-49-8W5	6-10-49-8W5	14-10-49-8W5

Table 4.1.2.3: Numerical Model Properties Based on Geological Model						
Stratigraphic Unit	Number of layers	Porosity (% bulk volume)		Permeability (mD)		Thickness (m)
		Average	Max	Average	Max	Average
Conglomerate	2	16.98	24.63	133.4	616.0	2.28
5&6 Sand	2	20.29	25.02	51.6	398.2	2.04
4 Sand	5	17.31	24.85	24.3	148.6	7.70
3 Sand	5	10.39	17.40	1.4	42.6	4.75
Full Grid	14	16.27	25.02	38.4	616.0	18.20

4.1.3 History Match

The history match was initially performed using the “black-oil” simulator IMEX as it takes only a few hours for the model to run to completion compared with more than twenty-four hours on the “compositional” simulator GEM. However, GEM was required to model the solvent and CO_2 effects accurately. All of the prediction cases were run on GEM.

The history match was conducted using historical data from December 1, 1962 through to January 1, 2008. Parameters matched included the oil, water and gas production rates and the cumulative oil, gas and water produced. The average reservoir pressure was also matched.

Early runs showed that the production wells were influenced by injection wells outside the area modeled. This effect was modeled by introducing four "dummy wells" or "pseudo-injectors" on the boundary of the model. These wells were controlled by injection rates that were set to a fraction of the injection into nearby injectors outside the boundary of the modeled area. The locations of these pseudo-injectors and their rates were adjusted to match the water cut of the producers near the edge of the model. Some adjustments were made to the relative permeability curves to match the water-cut and the GOR.

Initial runs showed that the historical injection rates were not matched. The injectivity of the wells was increased by the use of pressure-dependent permeability around the wells in the NE-SW direction. In this way the observed directional waterflood response was modeled. At some of the injection wells, the injectivity index of the well was also increased.

A field level history match for both the IMEX and GEM models is shown in Figure 4.1.3.1. The oil recovery factor at the end of the history match is 31.8% OOIP as shown in Figure 4.1.3.2, and the cumulative oil produced at the end of history is 1.77 x 10^6 m^3.

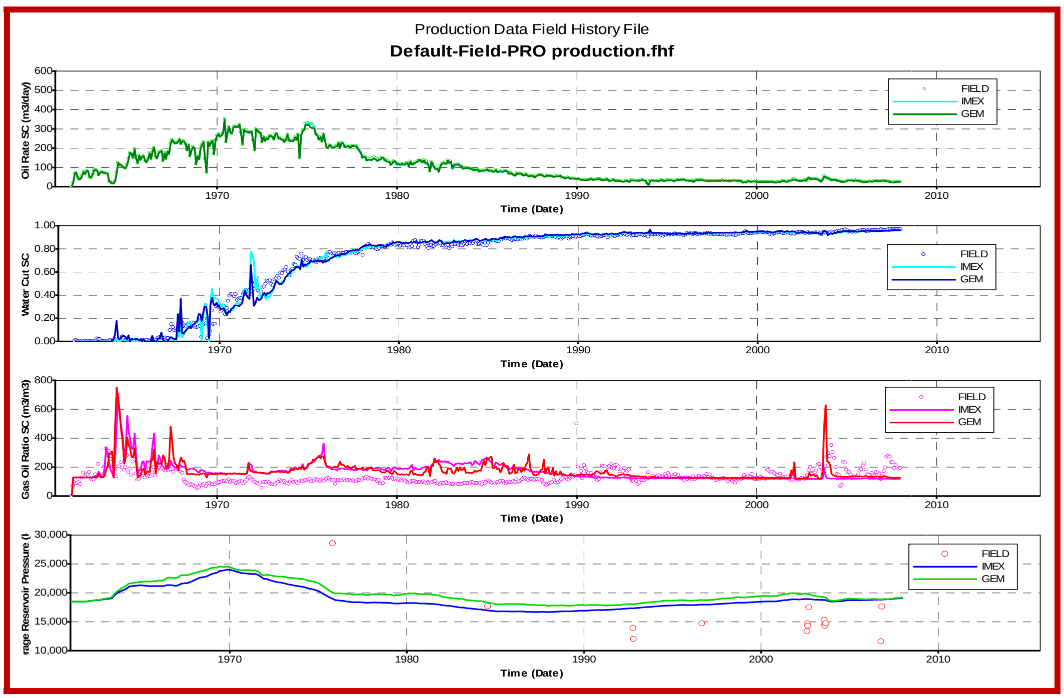


Figure 4.1.3.1: Comparison of IMEX and GEM history matches – Oil rate (m3/d @SC), water cut, GOR (m3/m3 @SC)) and pressure

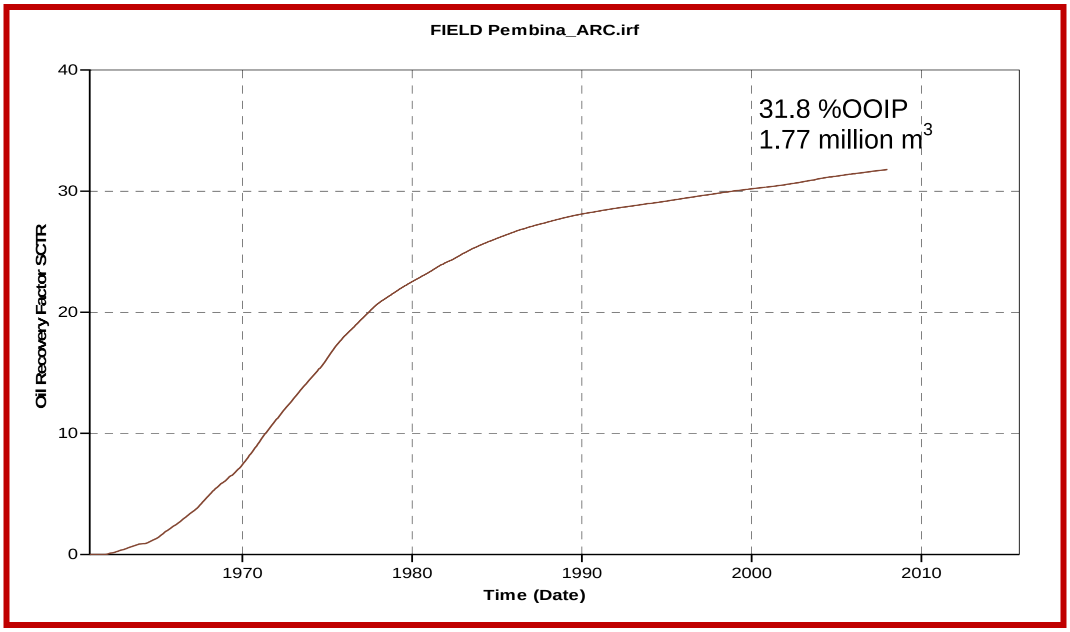


Figure 4.1.3.2: Cumulative oil production from sector model at end of history match.

4.1.4 Base Case Forecast

After a history match was achieved using IMEX, the model was converted for GEM. The GEM model was tested and fine tuned a little to improve the history match.

The following base cases were investigated:

1. Base Case – continuation of Waterflood with vertical wells on production at end of history match
2. Base Case – added horizontal wells in the 4 sand

Initial prediction runs were made with the existing producers and injectors operating at the end of the history match. These showed that the time required to flood the field was excessive (of the order of hundreds of years). The key to developing a successful CO_2 flood is to increase the "processing rate", i.e. increase the injection and production rates in the model area. Since the injection wells were injecting at below their capacity, it was the production rate that needed to be increased.

The production rate can be increased by reducing the well spacing (by drilling infill wells) or by adding wells with higher productivity. The number of vertical wells which would be required to increase the production rate sufficiently was very high and would probably be uneconomic. Adding two horizontal infill wells increased the processing rate sufficiently.

Horizontal wells have had variable success in the Pembina Cardium, however, a recent well stimulated with multiple fracs has shown considerably higher productivity than any vertical well. In Base Case 2, two horizontal wells were added near the bottom of the 4 sand. Their location was determined based on an analysis of where there was the most remaining oil after the historical production. All the other wells were left open in all the layers. The injection rate in all cases was controlled such that voidage replacement was maintained.

4.1.5 CO_2 EOR Forecasts

Four different CO_2 forecasts were carried out:

1. CO_2 Injection – no water
2. CO_2 Injection – WAG ratio 1:1
3. CO_2 Injection – WAG ratio 1:2
4. CO_2 Injection – WAG ratio 2:1

The properties of CO_2 were introduced based on standard correlations. The effects included the reduction in the oil viscosity, swelling of the oil and relative permeability effects. The minimum miscibility pressure (MMP) was found to be ~15000 kPa.

For the "water-alternating-gas" (WAG) schemes, the cycling between CO_2 and water injection was set so that 0.05 hydrocarbon pore volume (HCPV) of CO_2 was injected followed by the appropriate HCPV of water to reach the desired WAG ratio (defined as the ratio of water injected to CO_2 injected) in each cycle. The WAG scheme was stopped when the total CO_2 injection was equivalent to 0.5 HCPV. For the waterflood cases, the run was stopped when two HCPV of water had been injected in the prediction period.

The injection rate in all cases was controlled such that voidage replacement was maintained. Sensitivities were done to maintain different average reservoir pressure during the prediction period. In the final runs, the average reservoir pressure was maintained at about 21 MPa. The forecast cases, including Base Case waterflood forecasts, are summarized in Tables 4.1.5.1 and 4.1.5.2.

Table 4.1.5.1: Summary of Simulation Runs for NPCU sector model

Run Descriptions	Infill	CO_2 (%HCPV)	H_2O (%HCPV)	WAG Cycle	WAG Duration years	Total Prediction Years
History Match		-	80	-	-	46
Waterflood Baseline		-	280	-	-	55
Waterflood with new horizontal wells	2	-	280	-	-	26
WAG 1:1	2	51.2	227	1:1	21	32
WAG 1:2	2	52.3	204	1:2	16	25
WAG 2:1	2	51.4	279	2:1	31	39

Table 4.1.5.2: History Match and Forecast Results for NPCU sector model

Run Descriptions	Oil Recovery %OOIP	Incremental Recovery %	Recovery CO_2 %HCPV	Gross CO_2/ Oil ratio sm^3/sm^3	Net CO_2/ Oil ratio sm^3/sm^3
History Match	31.8		-	-	-
Waterflood Baseline	40.1		-	-	-
Waterflood with new horizontal wells	39.6		-	-	-
WAG 1:1	45.7	6.1	40.7	696	128
WAG 1:2	44.5	4.9	40.6	734	138
WAG 2:1	46.9	7.3	41.9	682	111

It was observed that continuous CO_2 injection gave poorer performance than the WAG cases because of poor sweep efficiency. At the end of each run, all of the wells were still on production, producing at rates between 0.4 m^3/d and 13.6 m^3/d (except Horizontal Producer 2 in WAG 1:1 and Well 02-11 in WAG 2:1 case).

Oil has been swept from the upper conglomerate and 5 & 6 sand layers more effectively than the lower 3 and 4 sands. Higher mole fraction of CO_2 is observed in the conglomerate layer and the 4 sand and much lower mole fraction in the 5&6 sand and 3 sand layers.

4.1.6 Area Models

To perform the simulation parametric studies and extrapolations in NPCU-1, an area of interest in the center of NPCU-1 was defined based on production performance and subdivided into six sub-areas corresponding to "Project Areas" defined by ARC Resources (See Figure 5.2.1.1). Additional geological models of selected areas were constructed to enable the extrapolation of the results of the "Pembina Cardium with Conglomerate" numerical simulation sector model to these other areas. The geologic models were used to derive initial-oil-in-place estimates and representative reservoir parameters for the simulation parametric studies and extrapolations. Reservoir parameters were calculated for each of the subareas for the parametric studies and extrapolations.

The history-matched model was taken as a starting point and the geological properties (net pay, porosity and permeability) were adjusted to represent the six different areas identified in the geological evaluation. The forecasts were then rerun with the adjusted area models. The rationale for selection of the areas is presented in the Development Plan Section 5.2.1.

A number of runs were made to determine the optimal operating constraints in the models to obtain realistic results. In the final cases, the WAG injection was started when the water cut reached a certain level. The water cut criterion was based on extrapolation of the area water-oil-ratio from the historical production behaviour of the wells in each area of interest to the year 2013, the date that it is anticipated the CO_2 flood would commence. The water cut criterion was calculated for each area from the water-oil-ratio expected in the year 2013, the assumed start of the CO_2 flood, as WC=WOR/(WOR+1). Table 4.1.6.1 provides the summary of the historical data.

Table 4.1.6.1: Performance Data for Prospective EOR Areas – Pembina with thief zone

Area	Injectivity/well (m^3/d)	Productivity/well (m^3/d)	Extrapolated Water-Oil Ratio in 2013	Water cut In 2013	WF Recovery to date 10^6 m^3
2	100	30	13	0.92857	4.1
3	50	20	13	0.92857	4.6
4	60	35	18	0.94737	9.2
5	80	50	39	0.975	9
6	50	15	11	0.91667	2.25
8	100	40	19	0.95	8.5

For each area, one run was carried out with water injection only with the existing wells, one with two horizontal wells under waterflood and another with a WAG injection scheme with a WAG ratio of 2:1. The results are summarized in Tables 4.1.6.2 and Table 4.1.6.3.

Note that the waterflood recovery has increased in most areas to about 50%, from the original model where it was about 40%. This increase is the result of the longer operating history for these “areal” models.

Table 4.1.6.4: Summary of Simulation Runs for Prototypes

Run Descriptions	Infill	CO_2 (%HCPV)	H_2O (%HCPV)	WAG Cycle	WAG Duration Years	Total Prediction Years
OPT	2	51.6	2002	2:1	22	224
OPTArea2	2	52.0	1068	2:1	27	220
OPTArea3	2	51.1	1115	2:1	30	230
OPTArea4	2	51.1	1647	2:1	24	220
OPTArea5	2	51.5	1782	2:1	14	221
OPTArea6	2	49.0	343	2:1	95	192
OPTArea8	2	51.3	1078	2:1	22	225
OPTArea9	2	34.8	142	2:1	WAG Contd.	148

The incremental oil recovery ranges from 4.2% to 12.9% of the OOIP. Note that the process has not been optimized fully. Larger multiples of HCPV of CO_2 injection, even higher WAG ratios, greater well density and other parameters could be adjusted to optimize the economics.

Table 4.1.6.3: Results of Simulation Runs for Prototypes

Run Descriptions	Oil Recovery %OOIP	Incremental Recovery %OOIP	Recovery CO_2 %HCPV	Gross CO_2/ Oil ratio sm^3/sm^3	Net CO_2/ Oil ratio sm^3/sm^3
OPT _water	49.3	-	-	-	-
OPT _WAG	54.8	5.5	49.86	556.00	18.76
OPTArea2_water	49.5	-	-	-	-
OPTArea2_WAG	62.4	12.9	47.88	518.46	41.04
OPTArea3_water	44.7	-	-	-	-
OPTArea3_WAG	53.6	8.9	45.21	593.43	68.35
OPTArea4_water	50.6	-	-	-	-
OPTArea4_WAG	60.2	9.6	48.11	528.12	30.92
OPTArea5_water	51.1	-	-	-	-
OPTArea5_WAG	61.0	9.9	45.26	508.03	61.53
OPTArea6_water	46.3	-	-	-	-
OPTArea6_WAG	54.0	7.7	44.82	563.96	48.11
OPTArea8_water	48.8	-	-	-	-
OPTArea8_WAG	53.0	4.2	47.69	597.78	42.11
OPTArea9_water	41.7	-	-	-	-
OPTArea9_WAG	49.5	7.8	14.23	462.48	273.41

4.2 PEMBINA CARDIUM WITHOUT THIEF ZONE (NO CONGLOMERATE) PROTOTYPE

An area in the Penn West operated "A" Lease was selected as the prototype for the Pembina Cardium without thief zone numerical simulation. The area, in which Penn West has been operating a CO_2 pilot, is in Township 48, Range 9, West 5M. The area spans across several legal subdivisions from 5-12-48-9 W5 to 10-11-48-9 W5. The study area selected for reservoir modelling is in the heart of the Pembina Cardium field. It covers an area 3 km by 2.5 km (3 sections) that includes the pilot and its surrounding area. Over the selected target area for this study, the conglomerate is about 0.5 m thick or less. Numerical modelling was carried out by Alberta Research Council using Schlumberger's Eclipse simulator.

4.2.1 Geological Model

A geological model was provided by Penn West for this simulation study. The model, developed in Petrel software, was divided areally into 199 by 199 blocks with each block 20 m by 20 m in size. It was upscaled by Penn West to 15 vertical layers from its original 24 layers. The gridding coordinates for the model were oriented 45 degrees to align one axis of the model parallel to the permeability on-trend direction that runs in a NW-SE orientation. The model covers an area of about 1600 ha (6.2 sections). About 3.2 by 2.5 km of the area was carved out for the simulation study. The area, bounded by the red boundary as shown in Figure 4.2.1.1, has 800 ha (3.1 sections) of land and encompasses Sections 6, 7, and 18 of Township 48, Range 8, W5 and Sections 1 to 3, and 10 to 15 of Township 48, Range 9, W5.

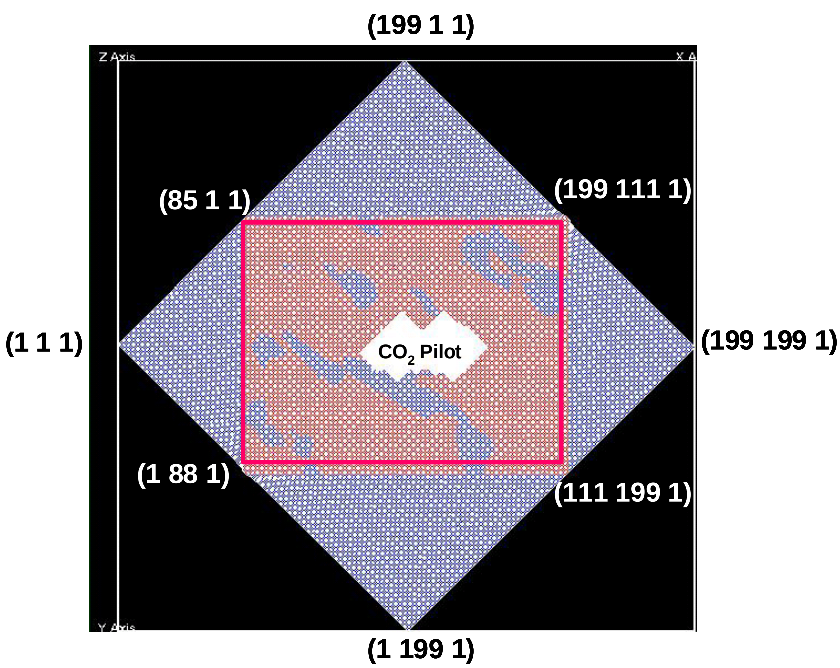


Figure 4.2.1.1: Penn West's 15-layer geological model

The Penn West geological model consists of four main units: lower sandstone, middle sandstone, upper sandstone and a thin conglomerate. Layer 1 comprises entirely of the conglomerate unit, layers 2 to 11 comprise of both upper and middle sandstones while layers 13 to 15 the lower sandstone. There is an insignificant barrier to vertical fluid flow between the upper and middle sandstone. The lower sandstone is separated from the middle sandstones by a regionally extensive shale barrier which is represented in the model as an inactive layer (layer 12). The petrophysical data for each block, such as average porosity, horizontal and vertical permeabilities, thickness and ratio of net to gross pay, were delineated and represented in the model. The tops of the formation structure were also provided and are shown in Figure 4.2.1.2. The variability of the reservoir attributes for the Cardium Formation in the simulation area is given in Table 4.2.1.1..

Table 4.2.1.1: Variability of the petrophysical properties in the Penn West geological model

	Tops mss	Porosity fraction	K_x mD	K_z mD	Thickness m	Net to Gross Ratio
Minimum	707.3	0.050	0.003	0.000	0.008	0.05
Maximum	761.6	0.215	455.1	302.5	6.327	1
Mean	732.8	0.145	10.021	1.690	1.108	0.758

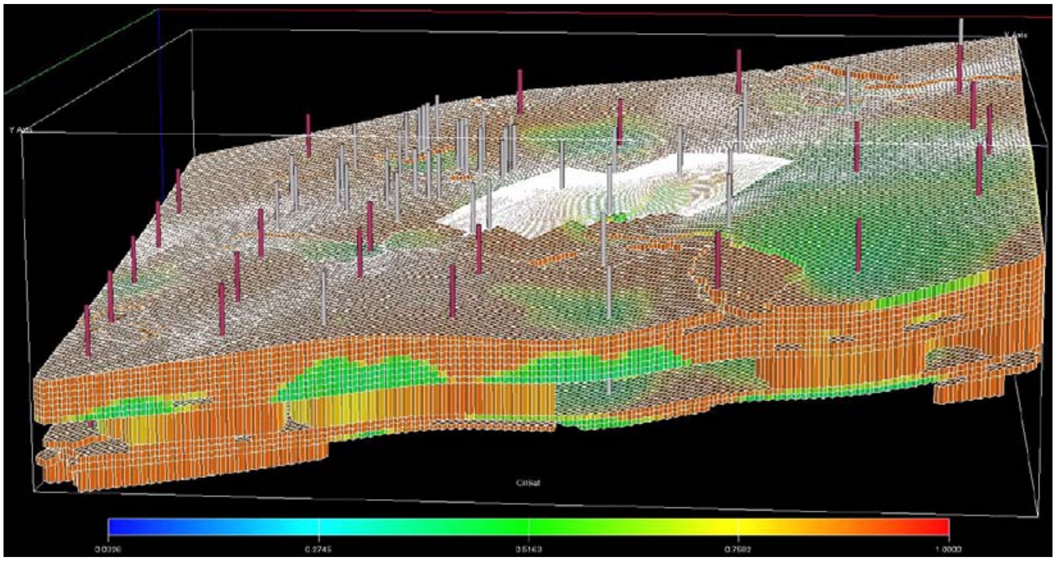


Figure 4.2.1.2: Pembina Cardium tops as shown by the Penn West 15 layer geological model

4.2.2 Numerical Model

The Penn West geo-model was incorporated into the ECLIPSE black oil simulator (E100) with the solvent mixing module. Petrophysical and fluid properties provided by Penn West were incorporated into the model. The model area included Penn West's CO_2 pilot area. The grid blocks in the pilot area were further sub-divided into 25 finer blocks. The local grid refinement was done to reduce the block size effect for the two inverted 5-spot CO_2 pilots, which are situated in the center of the simulation study area.

The vertical to horizontal permeability ratios (K_v/K_h) were defined for each block in the model. The statistical average of the ratio is fairly low, about 0.17. There was no directional permeability trend shown in the model; the statistical average of the permeabilities in the x-direction is about the same as those in the y-direction. Nonetheless, the effect of permeability anisotropy was investigated in a water flood case which shows the effect on incremental recovery was smaller than 1% OOIP.

4.2.3 History Match

The area selected for this study was depleted under primary production beginning February 1, 1955 until the implementation of the water flood scheme in 1958. The earliest production from the area was from thirteen wells drilled in 1953 with production ranging from 4 to 15 m^3/d. Six wells were converted in early 1958 for water injection with the injection rate ranging from 10 to 27 m^3/d. A CO_2 miscible flood pilot started in two inverted 5-spot patterns in March, 2005. There were 67 wells operating in the target area over the 53 years of primary and water flood operations.

The approach used in the history match was to prescribe water injection rates and oil production rates as an input control. The simulation output for total liquid, water and gas production rates provides significant tests for the quality of the history match. A satisfactory match (figure 4.2.3.1) of field production was achieved by adjusting the water and oil permeability curves, primarily the k_{rw} curvature power and irreducible water saturation. Adjustment of localized fluid transmissibility around wells was made to take into account the effect of induced fractures. Also, well fractions for the wells located along the boundaries of the study area were set typically between 0.25 and 0.5 depending on their locations in order to achieve the injectivity and productivity of these wells.

The history match simulation was extended to the two year production of the CO_2 miscible flood pilot. Injection of CO_2 at the two injectors 02/10-11 and 02/12-12 of the pilot started in March 2005. An acceptable match of the pilot history was achieved (Figure 4.2.3.2).

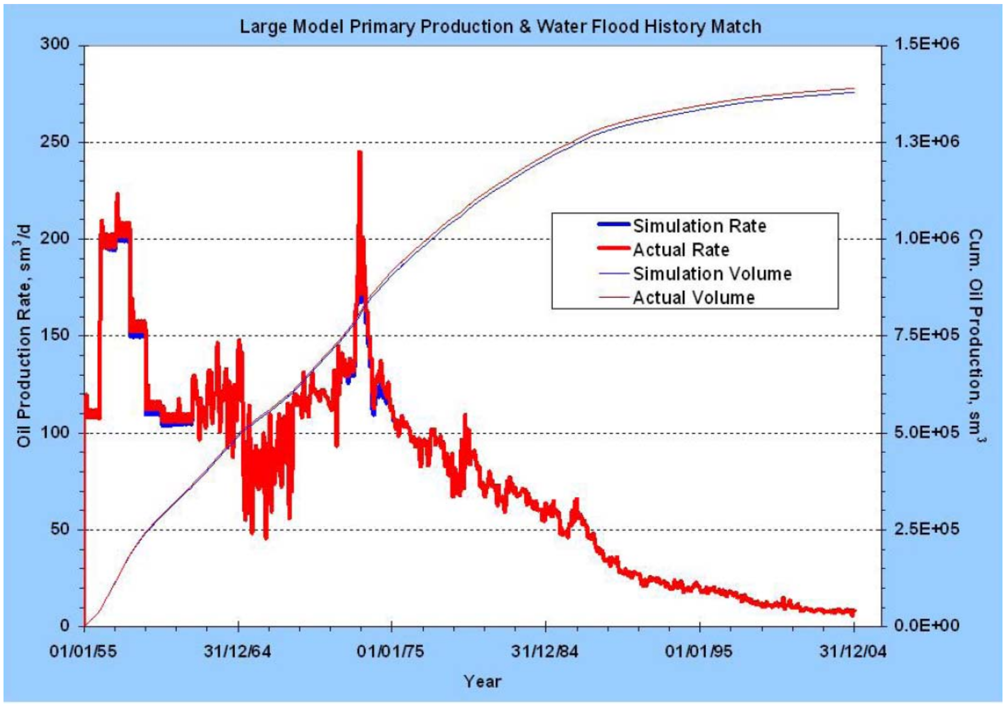


Figure 4.2.3.1: History match of oil production and rate during primary production and water flood

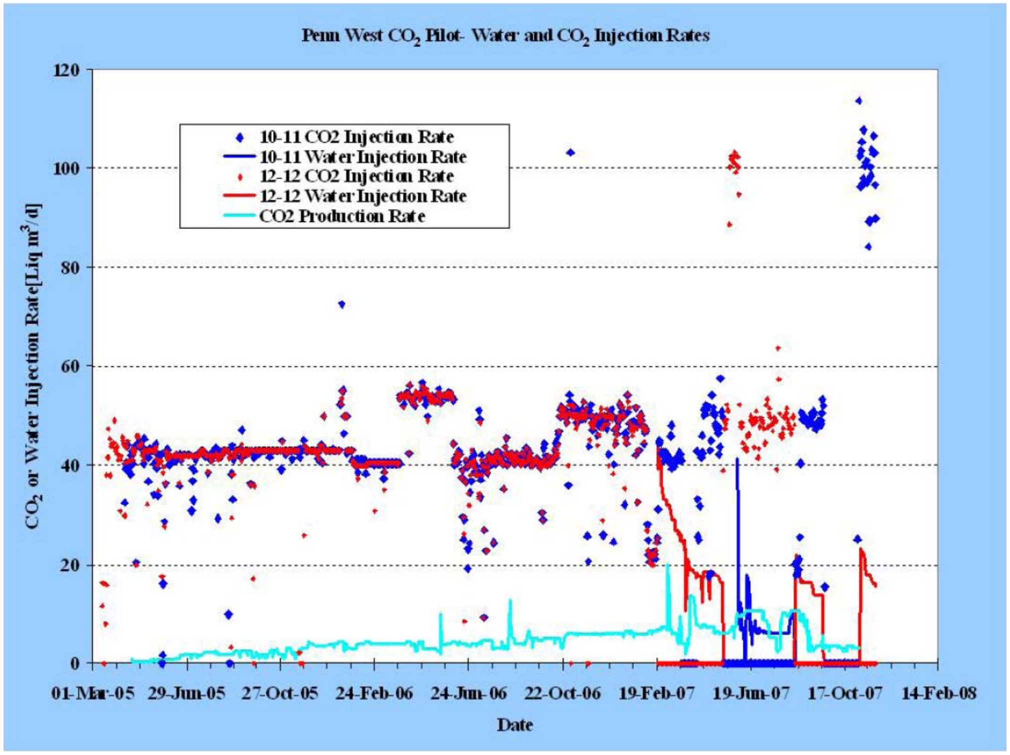


Figure 4.2.3.2: Injection rates for CO_2 and water at the CO_2 pilot

4.2.4 Base Case Forecast

Following history match, the numerical model was used to predict reservoir performance under certain development and operating scenarios. A line drive injection pattern that involved 44 wells was attempted over the entire simulation area with 1:1 WAG injection ratio. The run was found to be extremely slow with run time exceeding 10 days for the total injection to reach 1.0 hydrocarbon pore volume. To achieve a reasonable run efficiency, subsequent field prediction cases were conducted with a smaller sub-model extracted from the large model with which the water flood history match was performed. The sub-model was cut from the large model north-west of the existing CO_2 pilot, as shown in Figure 4.2.4.1.

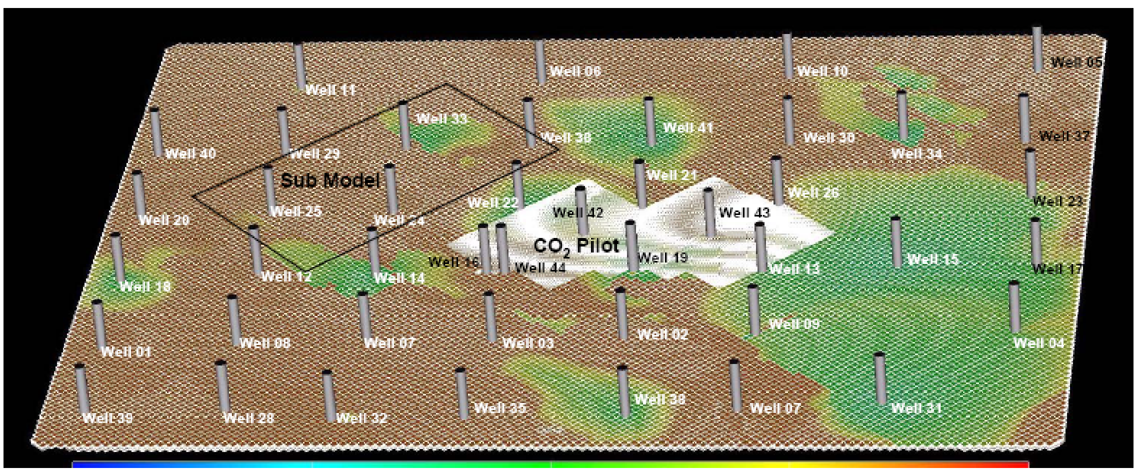


Figure 4.2.4.1: Location of the horizontal well sub-model relative to the existing pilot

The sub-model is about 1/8 th of the original simulation study area and has six vertical injectors and one horizontal producer. The well layout is shown in Figure 4.2.4.2. The six injectors are arranged in two rows on each side of the central, 1,000 m long, horizontal producer. The horizontal producer is located in layer 7 (middle of the middle sand); the vertical injectors are open to layers 4-10.

The initial reservoir conditions for the sub-model such as block saturations and pressure were taken from the end results of the large model base case which started at the end of the history match and carried on beyond December 1, 2010. Two field prediction cases were conducted with this sub-model: 1) baseline water flood and 2) CO_2 miscible flood with 1:1 WAG injection.

The waterflood prediction was performed to obtain baseline production so that net incremental recoveries of the WAG injection schemes over the baseline could be established. The run started on December 1, 2010 and continued for 35 years until total injection reached 2.0 HCPV. During this period, water was injected into the 6 wells at the constant rate of 25 rm^3/d, while the horizontal well produced at 150 rm^3/d. Since the voidage replacement ratio (VRR) was maintained at 1.0, the average reservoir pressure remained relatively constant at 20 MPa throughout this period. Incremental recovery reached 9% from the baseline water flood simulation. Production rates are shown in Figure 4.2.4.3.

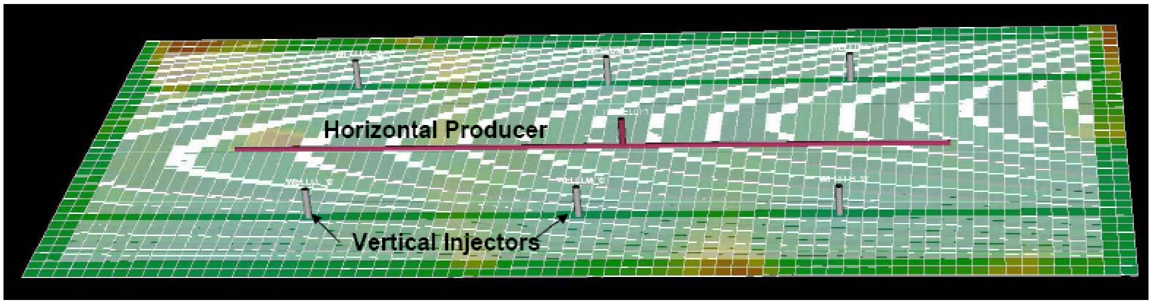


Figure 4.2.4.2: Configurations of vertical injectors and horizontal producer in the sub-model for field prediction cases

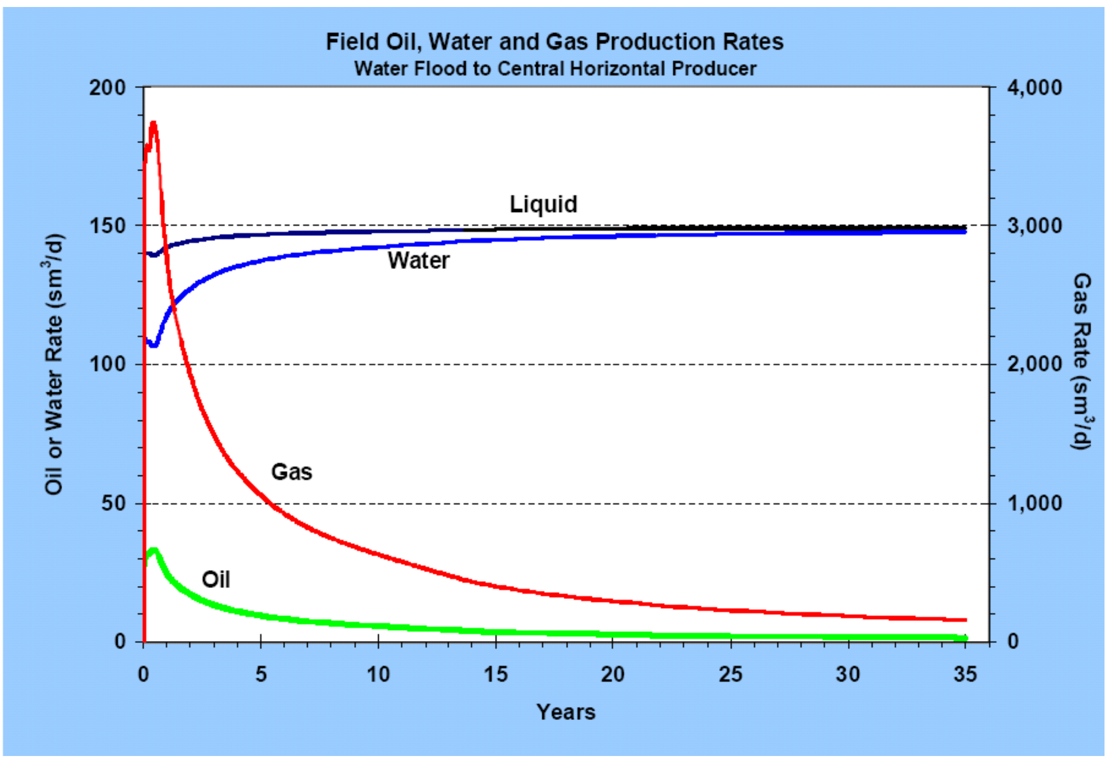


Figure 4.2.4.3: Production rates from base line waterflood case

4.2.5 CO_2 EOR Forecast

One WAG prediction case was performed with the sub-model. The WAG starting date for the prediction was chosen to be on November 11, 2017 when the water cut of the produced liquid reached 95% in the baseline waterflood case. Initially, in each WAG cycle, CO_2 was injected at the rate of 150 rm^3/d into the six vertical injectors for a month; this was followed by a month of water injection at the same rate. The injection rate was reduced to 120 rm^3/d six years after the start of the WAG injection due to the productivity decline of the horizontal producer. The WAG ratio was 1:1 in both instances. Throughout the run, the horizontal well was controlled to produce about the same rate as the total injection rate in reservoir volume with its minimum BHP set at 3 MPa. This pressure was a constraint that never came into play as the pressure never dropped below 15 MPa.

Gross CO_2 injection to produced oil ratio climbs to 3,137 sm^3/m^3 (17.6 mscf/bbl) at the end of the WAG injection but drops to 2,825 sm^3/m^3 (15.8 mscf/bbl) at the end of chase water injection. The corresponding net CO_2 to oil ratios are 808 sm^3/m^3 (4.53 mscf/bbl) and 510 sm^3/m^3 (2.86 mscf/bbl), respectively. The gross ratio is the total amount of CO_2 injection divided by the cumulative oil production. The net CO_2 to oil ratio is based on the net CO_2 injection assuming that all the produced CO_2 can be recycled.

Figure 4.2.5.1 compares the incremental oil recovery from WAG injection with that from the baseline water flood case. The incremental recovery reaches 18.8% at the end of the WAG injection, as compared to 9.0% from the baseline water flood case at 1.9 HCPV injection. The net incremental recovery between the two cases is 9.8%, which would exceed 10% at the end of the chase water injection when the incremental recovery by WAG process reaches 20.3%.

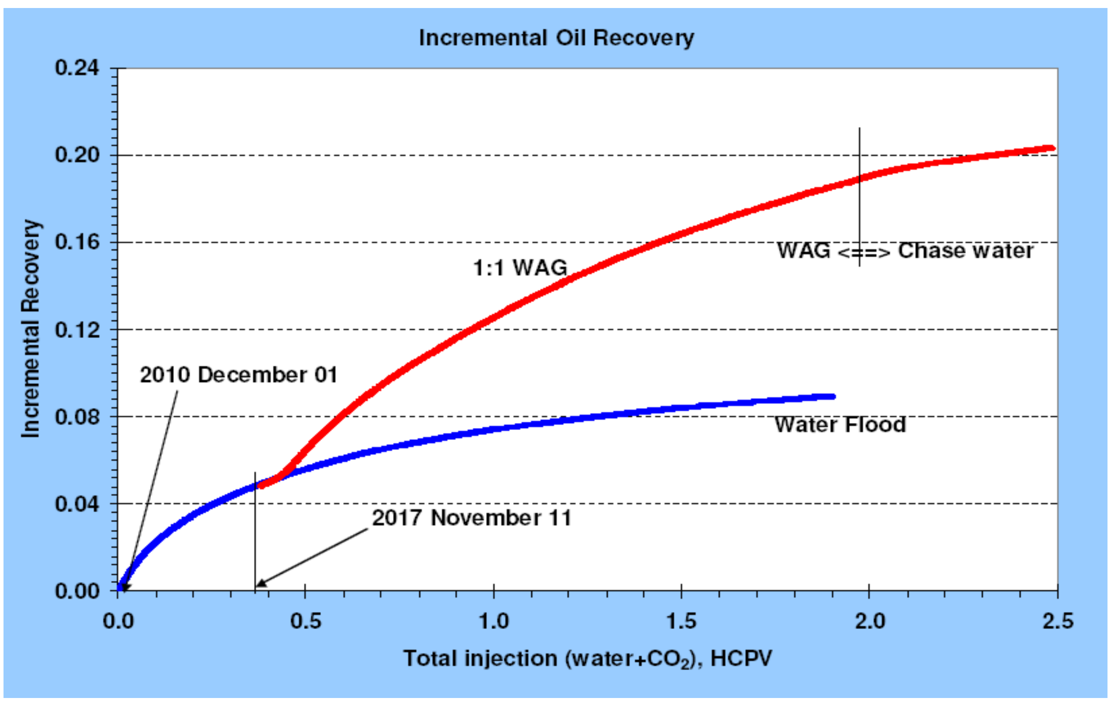


Figure 4.2.5.1: Incremental oil recovery from WAG injection as compared to baseline water flood case

4.2.6 Area Models

Area models were not developed for the Pembina without thief zone prototype.

4.3 BEAVERHILL LAKE WATERFLOODED PROTOTYPE

The Pengrowth operated Judy Creek BHL 'A' pool was selected as the prototype for Beaverhill Lake waterflood areas. A sector approximately 1.6 sections in area, encompassing wells in parts of Sections 25, 26, 35 and 36 of TWN 63, R11 W5M, was selected for simulation. The geological model was developed by Divestco using Pengrowth supplied 3-D grids of the geological tops of the reef. The simulation was conducted by the Alberta Research Council.

4.3.1 Geological Model

The term "Swan Hills Formation" is applied to reefal carbonate complexes and isolated reefs such as the Judy Creek and the Swan Hills reefs in the Swan Hills area of west-central Alberta. The Swan Hills Complex is a 100 – 120 m thick succession of restricted to shallow-water carbonates that form an extensive carbonate bank sequence comprising several shallowing-upwards reefal cycles, each 10–15 m thick. Each cycle is characterized by a windward, east-facing, high-energy reefal margin that separates the low-energy reef interior from the open marine basin (figure 4.3.1.1).

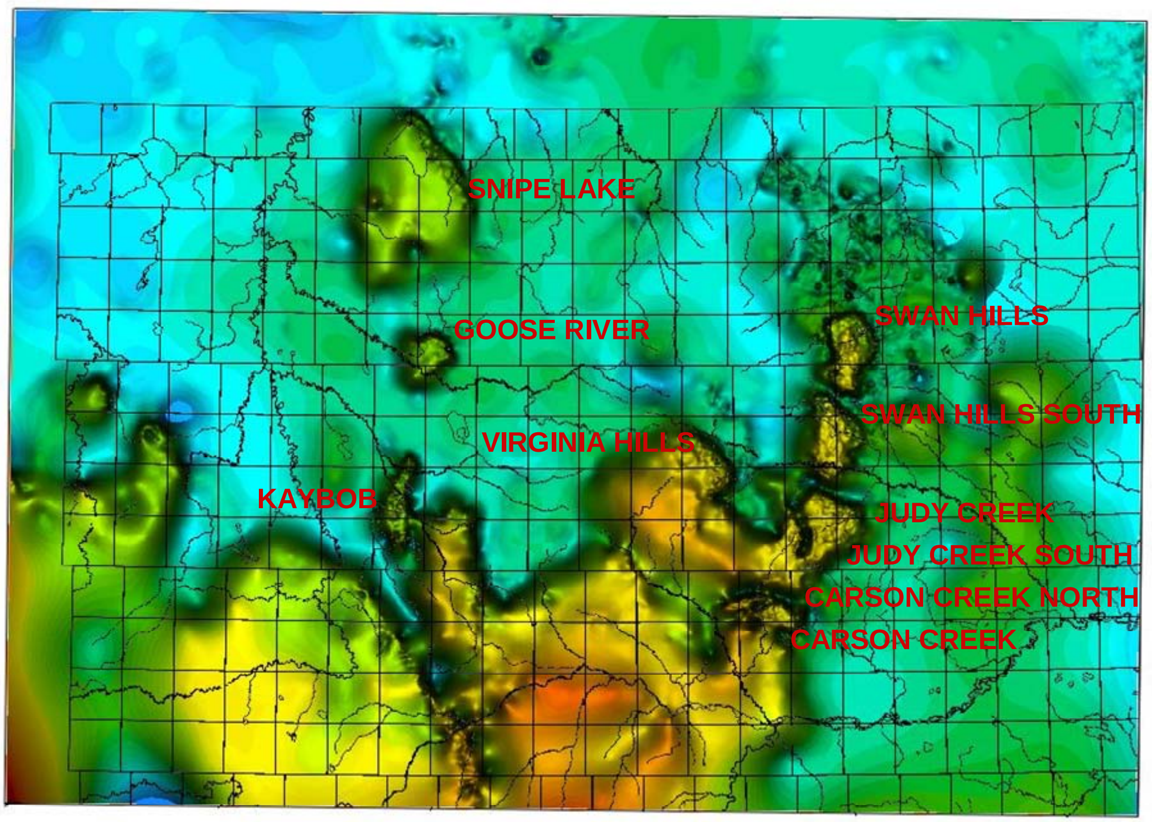


Figure 4.3.1.1: Swan Hills Complex and associated isolated Swan Hills Reefs. Source: Divestco Swan Hills Regional Model.

The Judy Creek Beaverhill Lake “A” pool, discovered in 1959, is one of several large, isolated, atoll-like, limestone oil-bearing reefs located to the north of the Swan Hills Complex (Batycky et al, 2007). The oil pool is formed by a stratigraphic trap in the Swan Hills Formation of the Beaverhill Lake Group. The reef has a porous organic reef margin with excellent porosity and horizontal and vertical permeability, particularly along the high energy northeast (windward) margin. The organic reef surrounds a more stratified interior lagoon characterized by lower porosity and permeability and poorer horizontal and vertical reservoir continuity.

The reef is characterized by five cycles of reef growth: R1 (base), R2, R3, R4 and R5 (top). These cycles have a back-stepping arrangement, and the cycles become progressively smaller towards the top of the reef.

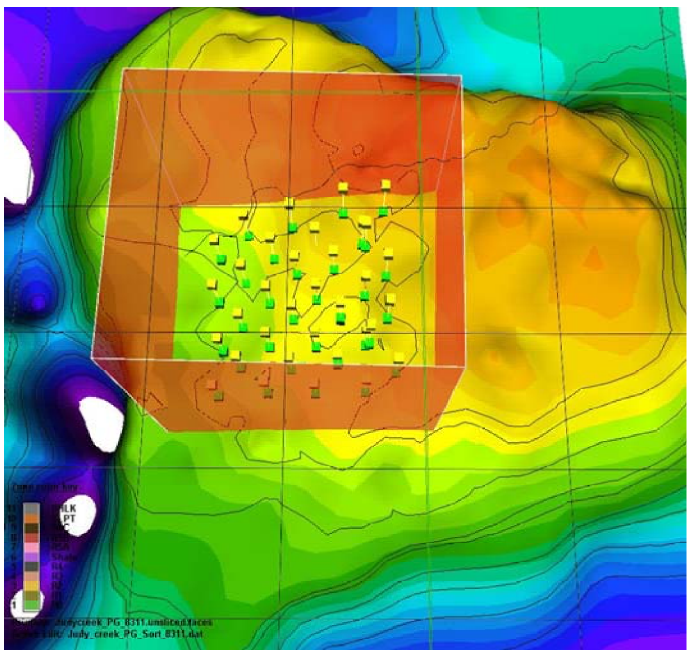


Figure 4.3.1.2: Location of Judy Creek prototype geological model (red curtain), and well control in the model area.

The orientation of the geological model (Figure 4.3.1.2) is north-south. Cells with dimensions of 25 m x 25 m x 30 cm oriented parallel to the model boundaries were used to construct the model. Pengrowth supplied 3-D grids of the geological tops of the entire reef which were used to construct the structural-stratigraphic framework of the model. Pengrowth also provided 3-D rock property grids that were used to construct the rock property model (porosity and maximum horizontal permeability). The geological model contains 81 X 81 X 180 cells - the high degree of vertical resolution was used to capture vertical variations in reservoir properties that will affect conformance in the reservoir. The model was exported in RESCUE format for numerical simulation studies.

4.3.2 Numerical Model

The sector numerical model derived from the geological model had 31,117 grid blocks. The grid had 29 x 29 x 37 blocks in the x, y and z directions, respectively. The grid blocks were 71 m square and averaged 2.3 m in height. To the extent possible, the numerical model preserved the permeability and porosity of the geological model. The model covers four 5-spot patterns on 32 ha (80 acre) spacing.

The wells were introduced into the model at the locations and with the connections to the grid as specified by their completion records. Petrophysical and fluid properties provided by Pengrowth were incorporated into the model. Figure 4.3.2.1 shows the wells in a 3-D view of the model.

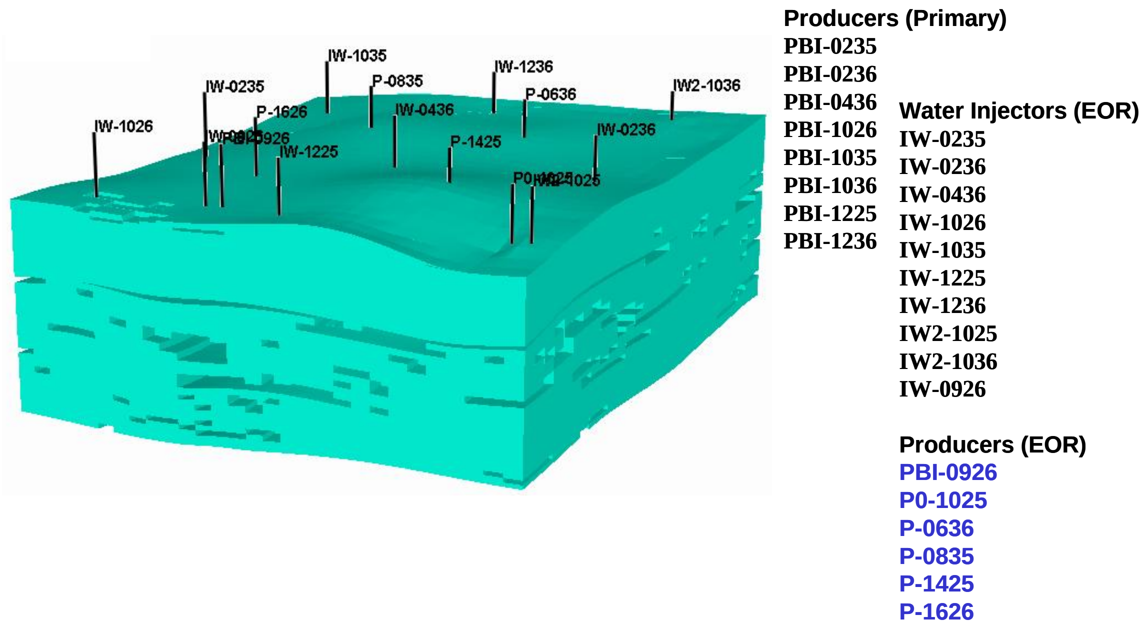


Figure 4.3.2.1: Well development (8 primary producers – converted into water injectors, 10 water alternative gas injectors and 6 active producers during EOR).

4.3.3 History Match

The field history consisted of approximately 15 years of primary depletion followed by approximately 30 years of waterflood. The main data available for history matching over this entire period were: water and oil injection/ production rates for all of the wells. Gas production has also been measured, but at the time of this study, gas rates were not considered reliable due to operational problems in the early days of operations. Despite information that the area had only experienced waterflooding, it had in fact been subjected to HMCF in the period 1986-2000. The simulation was conducted assuming that the sector had been waterflooded only. A consequence is that gas production could not be matched accurately.

A good field history match was obtained as shown in Figures 4.3.3.1 and 4.3.3.2. Oil recovery at the end of 2007 (end of production history) was 20.4% OOIP. There is clearly good agreement between the numerical simulation and actual field data.

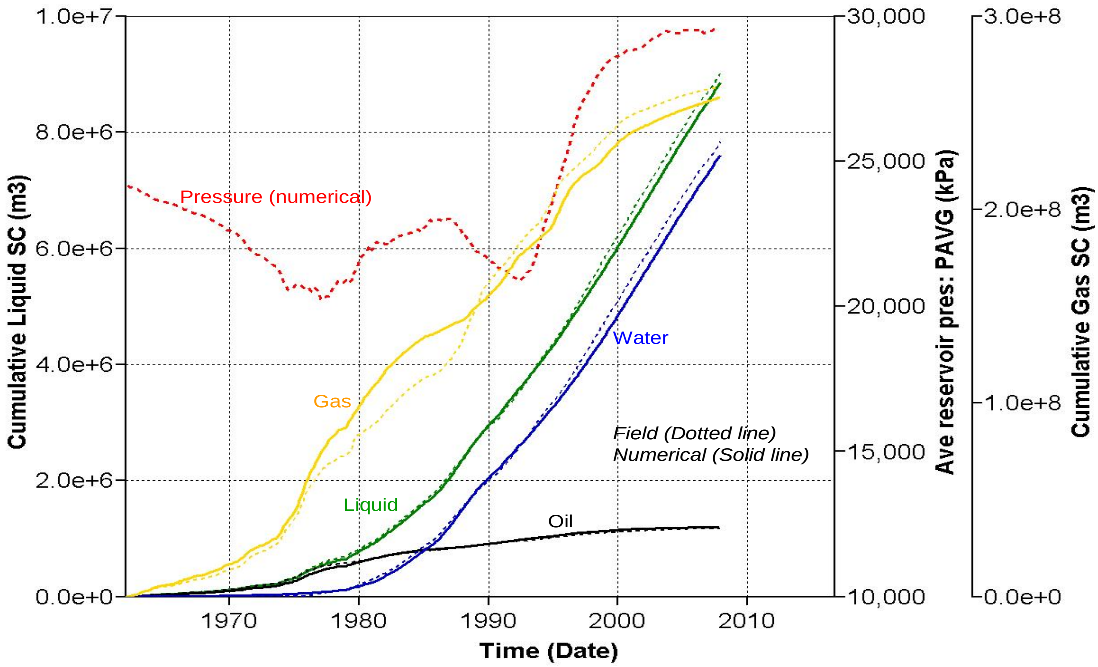


Figure 4.3.3.1: History match for cumulative oil, water and gas production and the simulated average field pressure - Judy Creek sector model

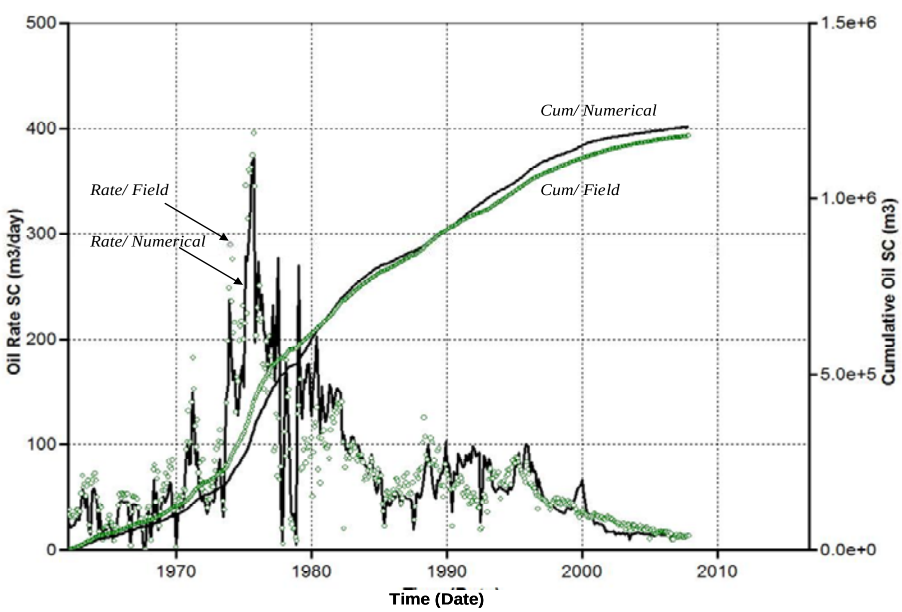


Figure 4.3.3.2: History match for oil rate and cumulative oil production - Judy Creek sector model

4.3.4 Baseline Forecast

The forecasting simulations take the history-match as a starting point and simulate a further 42 years, which ended in year 2050, of a baseline waterflood (Base Case) and CO_2 WAG recovery processes. A baseline forecast for continued waterflood was carried out using the wells still in operation at the end of the history match period with the existing water injection rates. Figure 4.3.4.1 shows oil rate and cumulative oil production for the baseline waterflood. The "do-nothing" continuation of the waterflood results in forecast recovery of 23.9%OOIP by the year 2050.

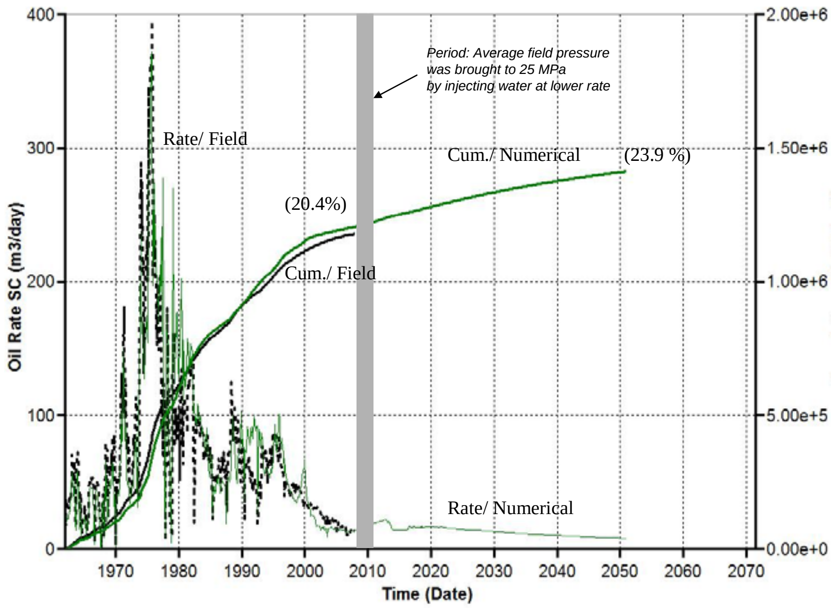


Figure 4.3.4.1: Baseline water flood forecast for Judy Creek sector model – Oil rate and cumulative oil production.

4.3.5 CO_2 EOR Forecasts

Forecasts were made for CO_2 flooding with different WAG ratios for the four 5-spot patterns; the WAG schedule was one month CO_2 injection followed by one month water injection. The forecasts were also performed with equivalent simultaneous injections for the four water-gas ratios. The simultaneous injection gave essentially the same results as the WAG. The simulation runs were more stable and ran more quickly using simultaneous injection. To take advantage of reduced run time, the forecasts were based on simultaneous injection of water and gas at water-gas (W/G) ratios of 1:1, 2:1, 3:1 and 4:1. Results in Table 4.3.5.1 of the WAG sensitivities show that the WAG 1:1 gives the best recovery by 2050. This can be attributed to the larger hydrocarbon pore volume of CO_2 injected during the period. The WAG 1:1 scheme increases the recovery to 44.8% OOIP, 20.9% OOIP above the base case waterflood. Note that at the end of the run, the oil rate was still about 60 m^3/d, which is about three times the current production rate, indicating that the true incremental oil from the CO_2 WAG is considerably higher.

Table 4.3.5.1: History match and forecast results for Judy Creek sector model					
Run Descriptions	Oil Recovery (% OOIP)	Injected CO_2 HCPV (%)	Recovery CO_2 (%)	Gross CO_2/ Oil ratio (Sm^3/Sm^3)	Net CO_2/Oil ratio (Sm^3/Sm^3)
History Match	20.4	-	-	-	-
Waterflood Baseline	23.9	-	-	-	-
WAG 1:1	44.8	142.8	86.1	2969	2559
WAG 2:1	43.8	134.0	83.1	2475	2059
WAG 3:1	41.5	63.9	78.2	2068	1610
WAG 4:1	35.5	36.2	60.8	1229	748

The average field pressure during the forecasting period varied from 25 MPa to 26 MPa. Based on these forecasting simulations, it can be concluded that both oil recovery and CO_2 storage would be enhanced by better control of individual wells and reservoir sweep during gas/water injection phase.

4.3.6 Area Models

The results of the Judy Creek waterflood history match and forecasts were extrapolated to four waterflood areas of Swan Hills. To extrapolate the results of the sector model to other waterflood areas, the sector model was modified to represent four geologic areas in the Swan Hills field. The areas are: WFA1, WFA2, WFA3, and WFA4 as shown in Figure 4.3.6.1.

For each geologic area, the permeability and porosity of the sector model was modified by a factor, determined from the ratios of the permeability-thickness product (kh_{area} / kh_{model}) and the porosity-thickness product ($Phi\text{-}h_{area}$ / $Phi\text{-}h_{model}$) of the geologic area to the sector model. This resulted in four models with different properties representing the areas. The properties of the four areas are shown in Table 4.3.6.1. The production and injection rates for the area models for the history portion of the simulation utilized those of the prototype multiplied by the ratio of hydrocarbon pore volume of the area model to that of the prototype.

The point at which the CO_2 WAG process commenced in the area models was based on predicted water cut in the current field operation at January 1, 2013 for the particular area. This is the date that it was assumed the CO_2 flood would commence. The predicted water cut was determined from extrapolation of the historical water cut data from the ERCB production database. For each area a history match and baseline waterflood of the modified sector model was carried out. The CO_2 flood for the area model was then commenced at the time that the water-oil-ratio observed in the baseline waterflood matched to the predicted water cut at January 1, 2013.

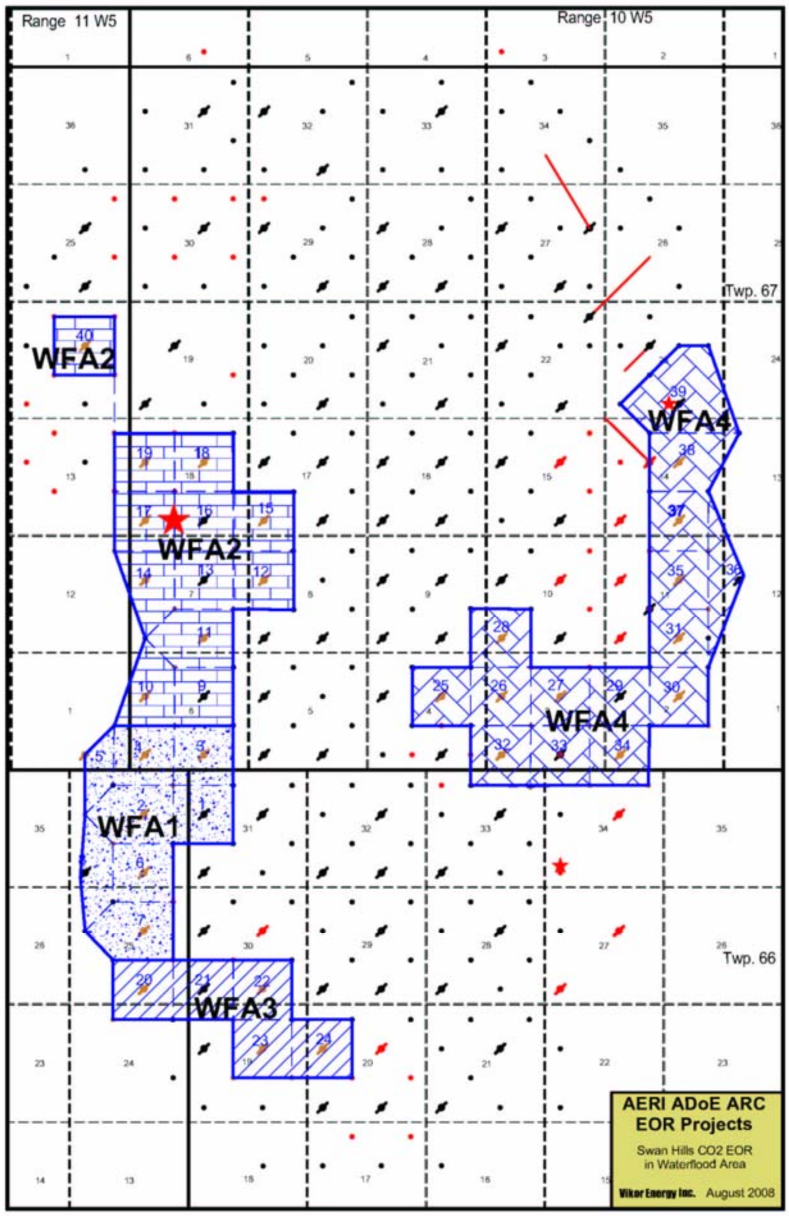


Figure 4.3.6.1: Waterflood areas in Swan Hills to which results of Judy Creek sector model were extrapolated

Table 4.3.6.1: Well injectivity, productivity and predicted WOR for Swan Hills waterflood areas

Area	Wells	Injectivity/well	Productivity/well	WOR in 2013
		m^3/d	m^3/d	m^3/m^3
WFA1 (W)	5	600	350	50
WFA2 (NW)	22	1000	300	50
WFA3 (SW)	13	200	300	200
WFA 4 (E)	45	1000	250	50

In terms of effectiveness of waterflood in enhancing reserves, based on ERCB historical data for the actual areas in the field, the most successful operations have been in the east area, followed by NW, SW and west. Data for the west area, based on only 5 operating wells may not be representative when the area is in-filled to complete various proposed patterns. Waterflood performance here was not very promising and correspondingly, viability of EOR here may need to be closely scrutinized.

Table 4.3.6.2 summarizes the waterflood and WAG 1:1 CO_2 recoveries from the area model forecasts. Table 4.3.6.3 provides data on CO_2 utilization observed in the model forecasts. Recovery of CO_2 from the area models was relatively high due to the length of time the chase water was injected, and will not be reflective of actual field performance.

Table 4.3.6.2: Results of Area Model Forecasts

Area	HCPV (10^6rm^3)	OOIP (10^6sm^3)	Oil Recovery at start of CO_2 injection (10^6sm^3/%OOIP)	Oil Recovery Baseline Waterflood (10^6sm^3/%OOIP)	Oil Recovery CO_2 WAG (10^6sm^3/%OOIP)	Incremental CO_2 Recovery over Baseline Waterflood %OOIP
WFA1	13.3	8.89	3.01 / 33.8	3.36 / 37.8	5.07 / 57.1	19.3
WFA2	13.1	8.71	3.41 / 39.2	3.73 / 42.8	5.53 / 63.5	20.7
WFA3	11.8	7.83	2.87 / 36.7	3.21 / 41.0	4.84 / 61.8	20.8
WFA4	10.5	6.97	2.57 / 36.8	2.79 / 40.1	4.81 / 69.1	29.1

Table 4.3.6.3: CO_2 Utilization in Area Model Forecasts

Area	CO_2 Injected (HCPV)	CO_2 Produced (HCPV)	Gross CO_2 utilization t/m^3 oil	Gross CO_2 utilization Mcf/bbl oil
WFA1	0.774	0.748	4.46	13.8
WFA2	0.69	0.653	3.77	11.6
WFA3	0.890	0.586	4.92	15.2
WFA4	0.879	0.803	3.47	10.7

4.4 BEAVERHILL LAKE SOLVENT FLOODED PROTOTYPE

The Swan Hills Unit #1 was selected as the prototype for Beaverhill Lake solvent flood areas. A sector approximately 1000 ha (4 sections) in TWN 67, R10 W5M, was selected for simulation. The geological model was developed by Divestco. The simulation was conducted by Computer Modelling Group.

4.4.1 Geological Model

The Swan Hills Unit #1 Field, discovered in 1957, is the largest conventional carbonate oilfield in Canada with an OOIP of 286 million m^3 (1800 MMBOE) (Anastas and Dobbin, 2005). The oil pool is formed by a stratigraphic trap in the Swan Hills Formation of the Beaverhill Lake Group (Figure 4.4.1.1).

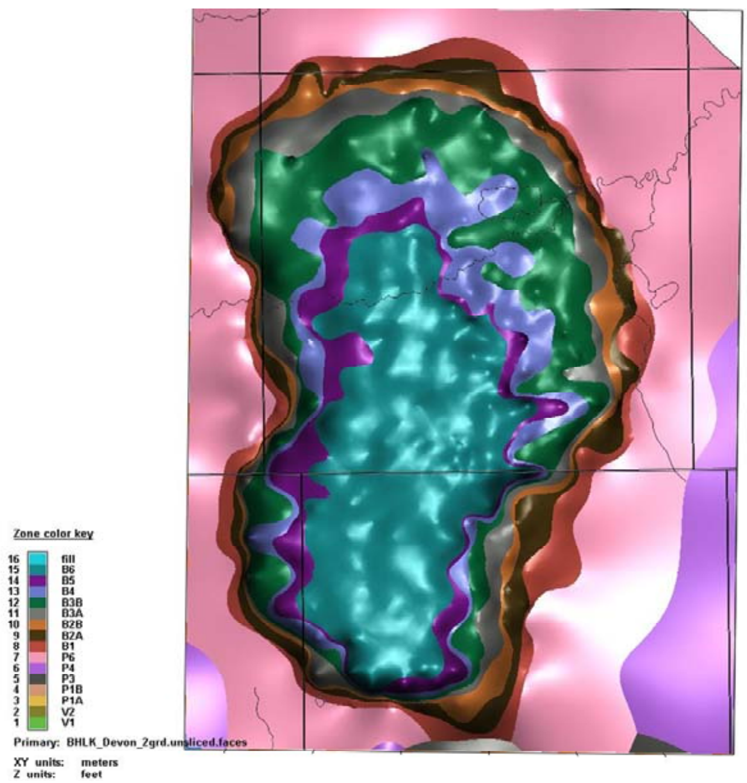


Figure 4.4.1.1: “Top view” of the Swan Hills Field isolated Swan Hills reef.

Due to the back-stepping nature of the reefal cycles at Swan Hills, the model area encompasses the reef-margin and fore-reef facies in upper cycles and the back-reef-lagoonal areas in lower cycles (Figure 4.4.1.3). The orientation of the geological model area is north-south. Cells with dimensions of 100 m x 100 m x 30 cm oriented parallel to the model boundaries were used to construct the model. The model area contains 31 X 30 X 576 cells- the high degree of vertical resolution was used to capture vertical variations in reservoir properties that will affect conformance in the reservoir. The model was exported in RESCUE format for numerical simulation studies.

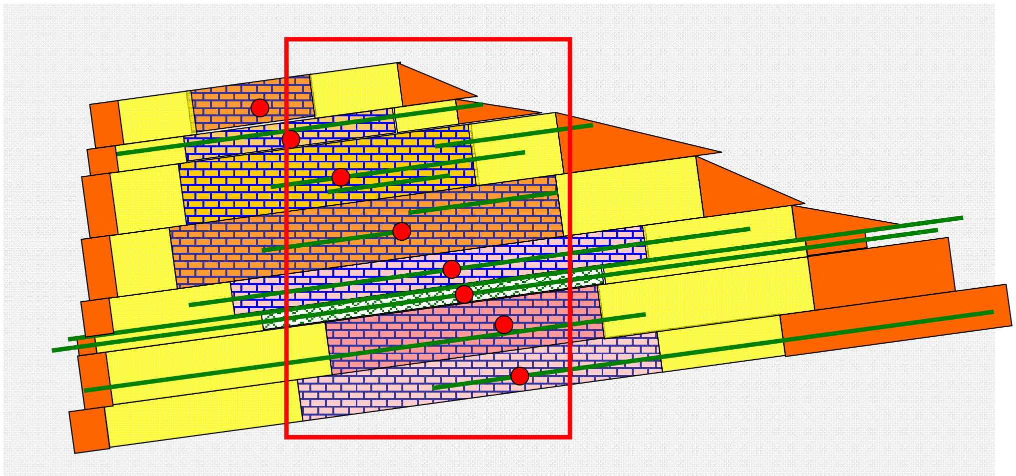


Figure 4.4.1.2: Location of the Swan Hills simulation model area and its relationship to the windward reef margin and lagoon.

4.4.2 Numerical Model

The geological model originally had 563 layers, which was upscaled to 24 layers for the simulation model (Figure 4.4.2.1). This included upscaling the porosity, the net-to-gross ratio and the permeability.

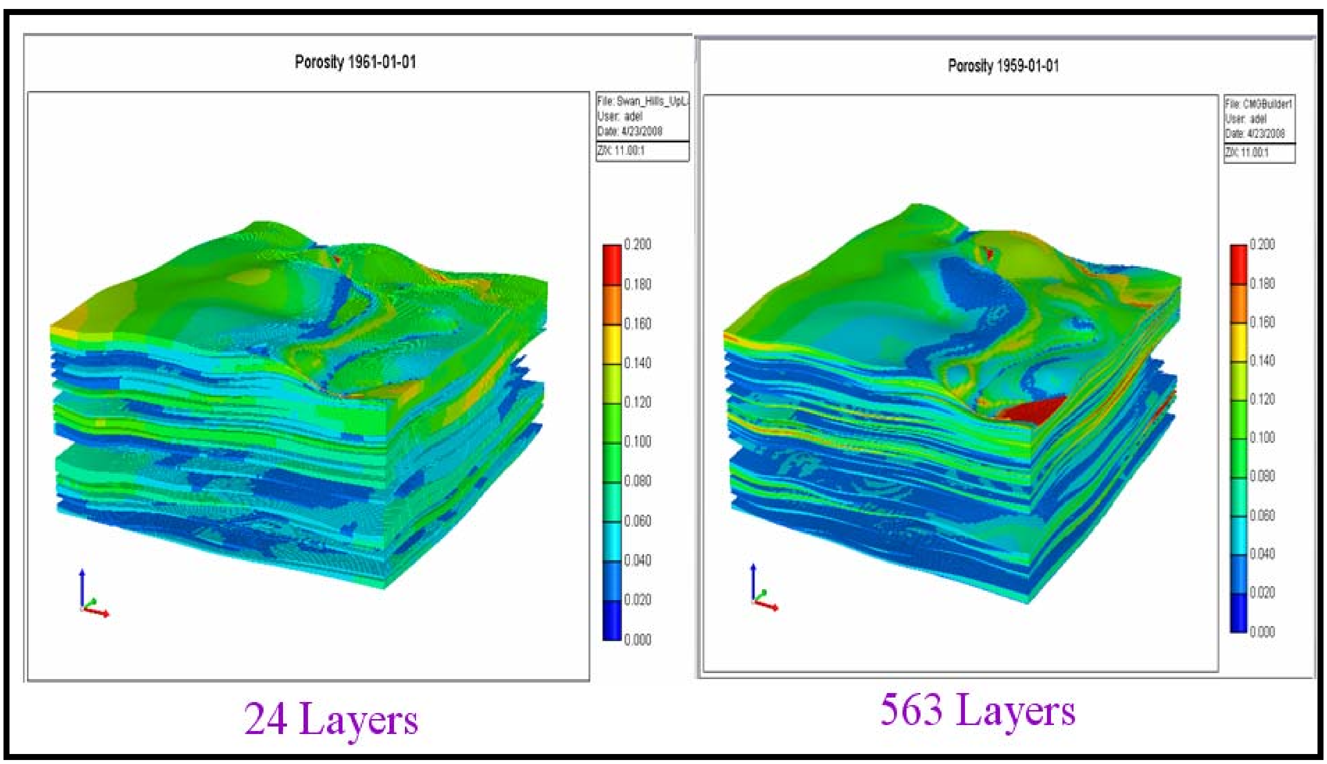


Figure 4.4.2.1: Numerical model (left) upscaled from Geological model (right)

4.4.3 History Match

For the history match, the wells were controlled by the historical oil production rates and the gas-oil ratio; water cut and pressure history were the matching parameters. The production in this field started in 1/1/1959. The first reported monthly production was in 1/1/1962. The cumulative production for the period from 1/1/1959 to 1/1/1962 was averaged and the calculated monthly oil production value was assigned to each well. Water injection wells were controlled by the monthly injected volumes.

For the solvent injection period, (from 1985 to 1994) the injectors were controlled by the solvent injection rates and the composition of the produced gas was used as an additional matching parameter. One well (00216067) injected CO_2 during the history match. The CO_2 injection started in October 2004 and continued for about two years.

The history match was initially performed using the “black-oil” simulator IMEX as it takes only five hours for the model to run to completion compared with more than twenty-five hours on the “compositional” simulator GEM. However, GEM was required to model the solvent and CO_2 effects accurately. All of the prediction cases were run on GEM. A good match was obtained for the field cumulative oil and gas production. The oil recovery factor in the simulated sector at end of the history match was 38.3 %OOIP (Figure 4.4.3.12).

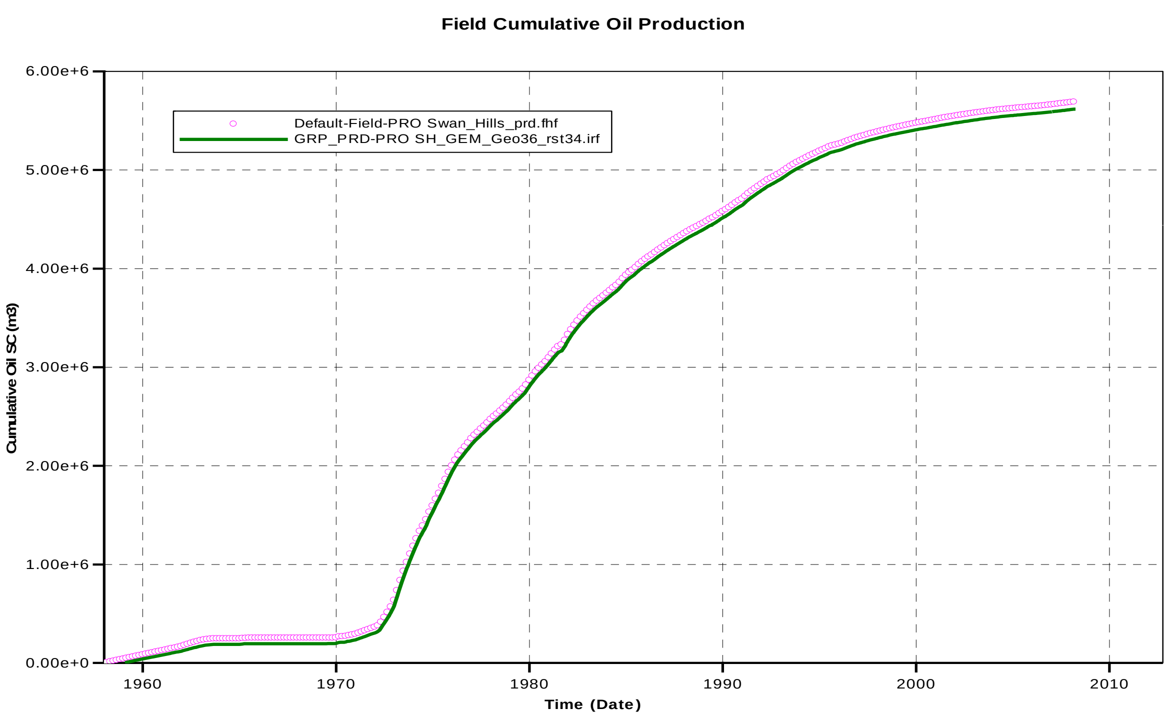


Figure 4.4.3.1: Cumulative Oil production, field data and history match, full sector

4.4.4 Base Case Forecast

The Base Case forecast is a "do-nothing" scenario and continues the waterflood following the history match using those wells still on production at the end of the history match. This Base Case forecast and the WAG of water/CO_2 injection forecasts have the same amount of solvent injected. Most of the solvent has been injected in the period from October 1985 to May 1995. The amount of water injected in the Base Case forecast was equal to 1.5 hydrocarbon pore volume (79 x 10^6 m^3) for comparison to the WAG prediction cases. To keep a smooth transition from the history match run to the prediction runs, a productivity index fraction was applied to control the well production at the beginning of the prediction cases. The oil recovery factor at the end of the run was 41.2 % OOIP.

4.4.5 CO_2 EOR Forecasts

Two prediction scenarios were run to investigate the effect of varying WAG scenario on enhanced recovery factor, WAG 2:1 and WAG 1:1. The two scenarios started after a water injection period that extended from the end of the history match to 1/1/2013 (which was the expected date to start the CO_2 WAG project).

During the CO_2 injection scenarios, the reservoir pressure was maintained at around 28,500 kPa, which was the last pressure measured at the end of the history match. The WAG 1:1 provided the highest production rate and the highest recovery factor. The results of the waterflood and CO_2 forecasts are summarized in Table 4.4.5.1.

Table 4.4.5.1: Waterflood and CO_2 Flood Forecasts BHL Solvent Flood Sector Model

	Oil Recovery		Water Injection	CO_2 Injection	Chase Water	Oil Recovery Increment Over Baseline	Gross CO_2 Utilization	
	$10^6 sm^3$	%OOIP	HCPV	HCPV	HCPV	%OOIP	t/m^3 oil	mscf/bbl oil
History match	14.2	38.3	-	-	-	-	-	-
Baseline waterflood	15.3	41.2	1.5	-	-	-	-	-
WAG 1:1	16.9	45.7	0.5	0.5	0.5	4.5	10.9	33.1
WAG 2:1	17.0	45.9	1.0	0.5	0.5	4.7	10.3	31.3

4.4.6 Area Models

To extrapolate the results of the sector model to other areas of the Swan Hills field, the sector model was modified to represent five of the geologic areas in the Swan Hills field: SFA1, SFA2, SFA3, SFA6 and SFA7 as shown in Figure 4.4.6.2. For each geologic area, the permeability and porosity of the sector model was modified by a factor, determined from the ratios of the permeability-thickness product (kh_{area} / kh_{model}) and the porosity-thickness product ($Phi\text{-}h_{area}$ / $Phi\text{-}h_{model}$) of the geologic area to the sector model. This resulted in five models with different properties representing the five areas.

Table 4.4.6.1: Predicted watercut and corresponding hydrocarbon solvent injection in the areal models at January 1, 2013

Area	Solvent (%)	Water-oil-ratio (%)	Water Cut	HCPV 10^7 rm^3	OOIP 10^7 sm^3
SFA1	35	30	0.96774	6.59	4.63
SFA2	15	50	0.98039	6.59	4.63
SFA3	5	50	0.98039	6.19	4.36
SFA6	5	100	0.99009	6.43	4.53
SFA7	40	200	0.99502	8.04	5.66

Because the proposed high water cut values delayed the start date of the WAG to between 50-100 years after the solvent injection The WAG injection was started at water cut of 0.90 instead of the predicted water cut.

Table 4.4.6.2 shows the recovery factors obtained from the area model runs. The table of recoveries shows that the areas exhibited very similar behaviour. The low incremental recovery in SFA6 is because chase water could not be injected into the model. With chase water, recovery would have been similar to the other areas.

Table 4.4.6.2: Recovery Factors of Swan Hills Solvent Area Models

Area	Oil Recovery at start of CO_2 injection		Oil Recovery Baseline Waterflood		Oil Recovery CO_2 WAG		Incremental CO_2 Recovery over Baseline Waterflood %OOIP
	($10^6 sm^3$)	(%OOIP)	($10^6 sm^3$)	(%OOIP)	($10^6 sm^3$)	(%OOIP)	
SFA1	8.52	18.4	11.6	25.0	13.1	28.3	3.30
SFA2	8.28	17.9	11.3	24.3	12.7	27.5	3.13
SFA3	6.66	15.3	10.6	24.2	11.8	27.0	2.75
SFA6	6.93	15.3	9.69	21.4	10.6	23.5	2.08
SFA7	8.91	15.7	13.3	23.4	14.9	26.3	2.86

Significant difficulty was experienced in the simulation. It was very difficult to maintain reservoir pressure above MMP using expected production rates; therefore productivity was constrained. Consequently the anticipated WOR at start of the CO_2 EOR was much lower than anticipated in the field. In spite of the precautions taken, the reservoir pressure dropped during CO_2 injection and miscibility may not have been maintained, especially in Area 2, reducing recovery. Thus, recoveries shown for the area models are pessimistic.

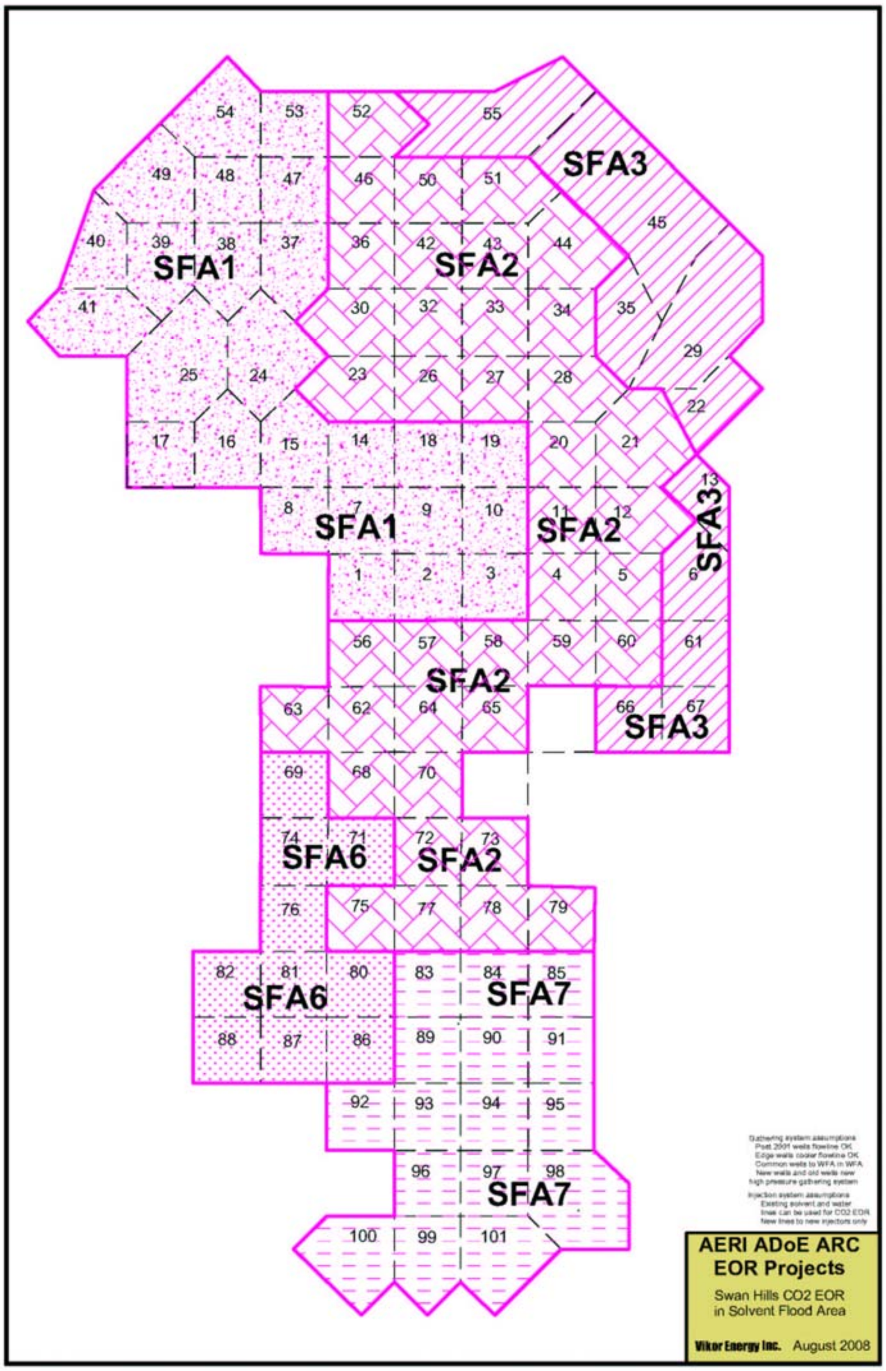


Figure 4.4.6.1: Geologic Areas and Pattern Layout Used for Areal Models and Development Plan (Section 5.2.4)

4.5 D-2/D-3 FIELD PROTOTYPE

The Redwater field operated by ARC Resources was selected as a prototype for D-2/D-3 pools. A sector of about 260 ha (1 section) in Sections 19 and 20 of Township 56 Range 20 W5 was selected for numerical simulation. A geological model was constructed by Divestco using reef structural elevations provided by ARC Resources. The numerical modelling was carried out by Alberta Research Council.

4.5.1 Geological Model

Upper Devonian (D-3) Woodbend Group carbonate reefs and build-ups contain about 32% of the initial conventional oil and gas reserves in Paleozoic strata in the Alberta Basin (Switzer et al, 1994). The principal D-3 oil and gas pools are located along the Rimbey-Meadowbrook reef trend and the Clive-Bashaw reef complexes south of Edmonton, and in the Sturgeon Lake-Simonette-Windfall area northwest of Edmonton. The Redwater D-3 Pool, discovered in 1958, is the largest Woodbend Group oil field in Western Canada.

An area in the southeast corner of the Redwater reef was modelled in detail for construction of a "D-3 Prototype Model" for numerical simulation. The model area is located in the reef-front and back-reef portion of the Redwater Reef, as shown in Figures 4.5.1.1.

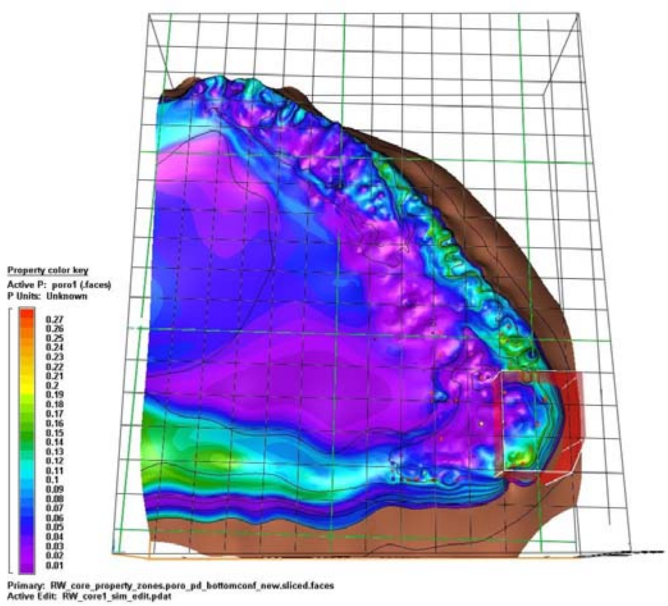


Figure 4.5.1.1: View of the eastern windward margin of the Redwater Reef showing the location of the Redwater Reef D-3 Prototype geological model and simulation area (red curtain).

The orientation of the geological model is north-south. Porosity and permeability models for the simulation area were built using a cell size of 50 x 50 x 0.3 m, conformal to the underlying Duvernay formation. The model area contains 85 X 97 X 288 cells - the high degree of vertical resolution was used to capture vertical variations in reservoir properties that affect conformance in the reservoir. Property models and layer grids were exported to the reservoir simulator using the Rescue format.

4.5.2 Numerical Model

The Computer Modelling Group (CMG) GEM compositional simulator was selected for the numerical simulation. The simulation model (Figure 4.5.2.1) for the study area was defined in a non-orthogonal corner point grid system as the geometry of the Redwater reservoir strongly impacts on the grid thickness distribution. The number of grid blocks in the simulation model was 49 × 33 × 21 (33,957 cells) after upscaling the layers of the geologic model. Analytical aquifers were attached to the bottom layer to mimic the water influx from the under-lying Cooking Lake aquifer. The compositional simulation model was constructed by integrating information related to the geological model, fluid model, rock fluid properties and reservoir initial conditions.

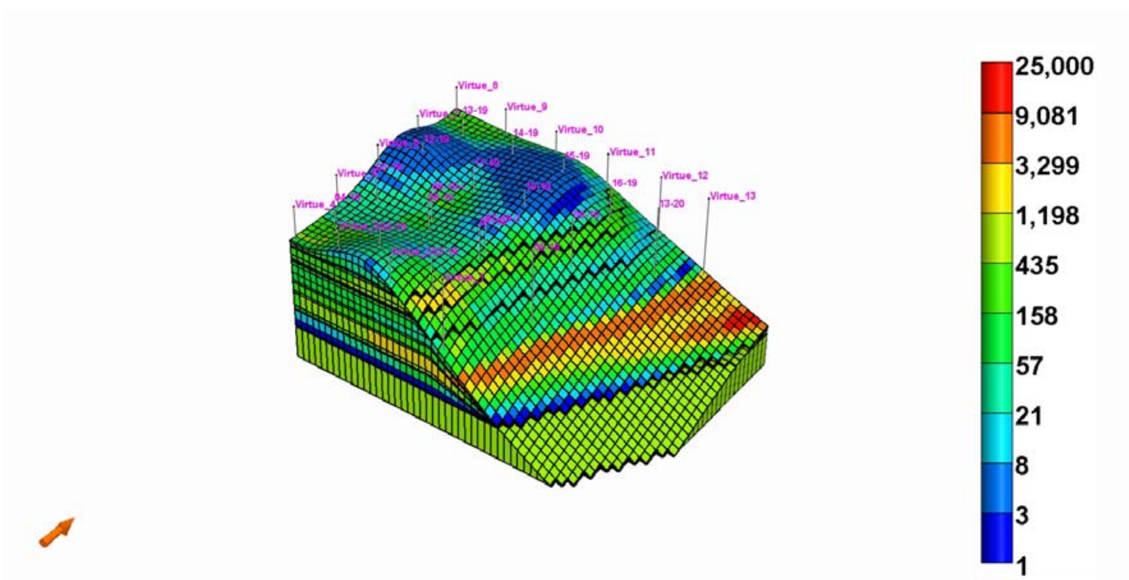


Figure 4.5.2.1: Numerical model showing well locations and model horizontal permeability

The initial reservoir pressure at the reference datum (about 355 mss) was 7239 kPa, and the reservoir temperature is 34˚C. At the start of the reservoir simulation, the reservoir was initiated with vertical hydrostatic equilibrium, with the water oil contact set at 377 mss and an initial oil saturation of 75% above the initial water-oil contact. Note that the MMP of the oil and CO_2 is about 9.5 MPa.

4.5.3 History Match

The 56 year production history of the wells in the model was history matched using CMG's GEM compositional simulator. In the history match, the liquid production rates of each production well and the water injection rates of the water disposal well were used as the primary well controls. The history match focused on the total oil, water, and gas production for the study area, the average reservoir pressure, and the oil, water and gas production for the production wells still operating at the end of the historical period.

The production history of the Redwater Leduc oil pool can be divided into two time periods: (1) primary production from 1949 until 1978; and (2) a massive water injection in disposal wells from 1978 to August 2006 (Figure 4.5.3.1).

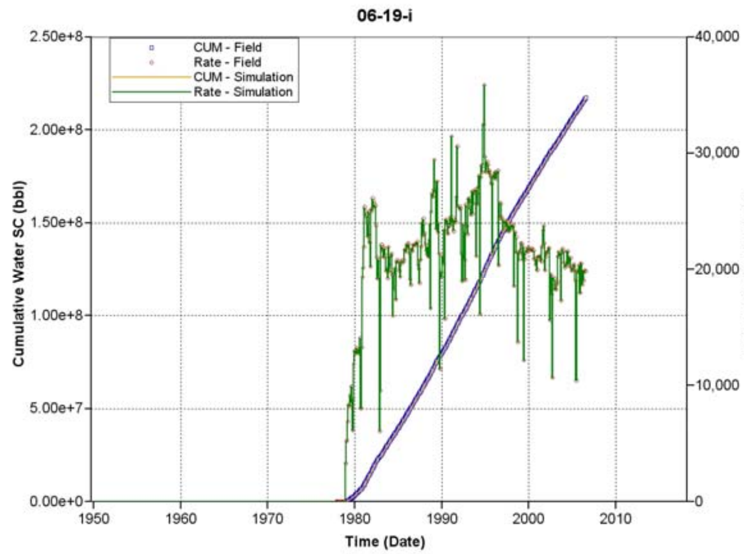


Figure 4.5.3.1: Historical Water Disposal Rate and Cumulative Volume

Figure 4.5.3.2 shows the simulated results of oil rate and cumulative production. Oil recovery at the end of 2007 (end of production history) from the sector was 53.5% OOIP.

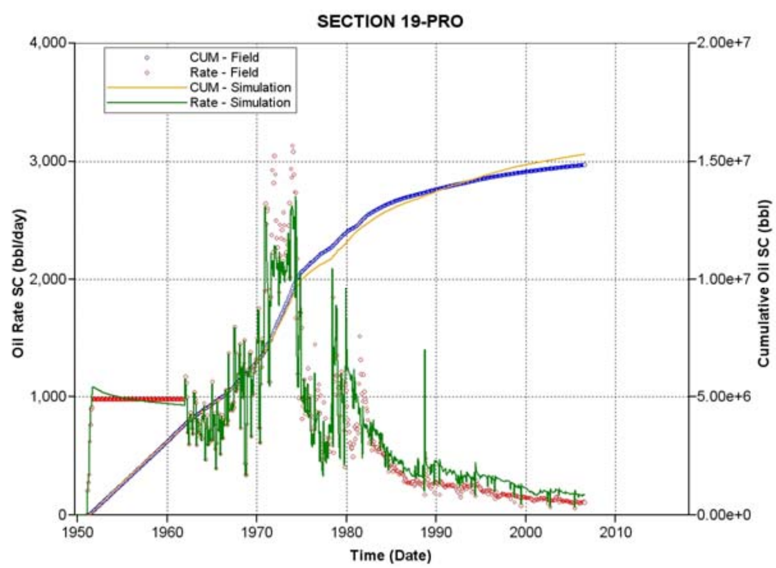


Figure 4.5.3.2: Sector History and Match of Oil Rate and Cumulative Oil Production

Of the 17 production wells, only 5 were still on production at the end of the history match; these are wells 03-19, 06-19, 10-19, 12-19 and 15-19. The other wells had a short production period and all of them were suspended or abandoned at the end of the history match period. The good history match shows that the numerical model captured the fluid flow behaviour and reservoir geological characteristics and can be used to predict the future performance of the study area.

4.5.4 Base Case Forecast

At the end of the history match the simulation area had one active water injection/disposal well (06-19-i) and five producing wells noted above. A "do-nothing" Base Case was run using the five producers still in operation while maintaining the water injection rate at the end of the history match into the 06-19-i injector (3180 m^3/d; 20000 bbl/d). The forecast utilized the existing bottom hole pressures (BHP) of the producing wells at the end of the history match.

Figure 4.5.4.1 shows oil rate and cumulative oil production for the Base Case. Total oil recovery from the Base Case was 55.2% OOIP after a further 25 years of operation. Thus, the incremental oil produced in the base case during the forecast period due to continued waterflood is 1.7% OOIP.

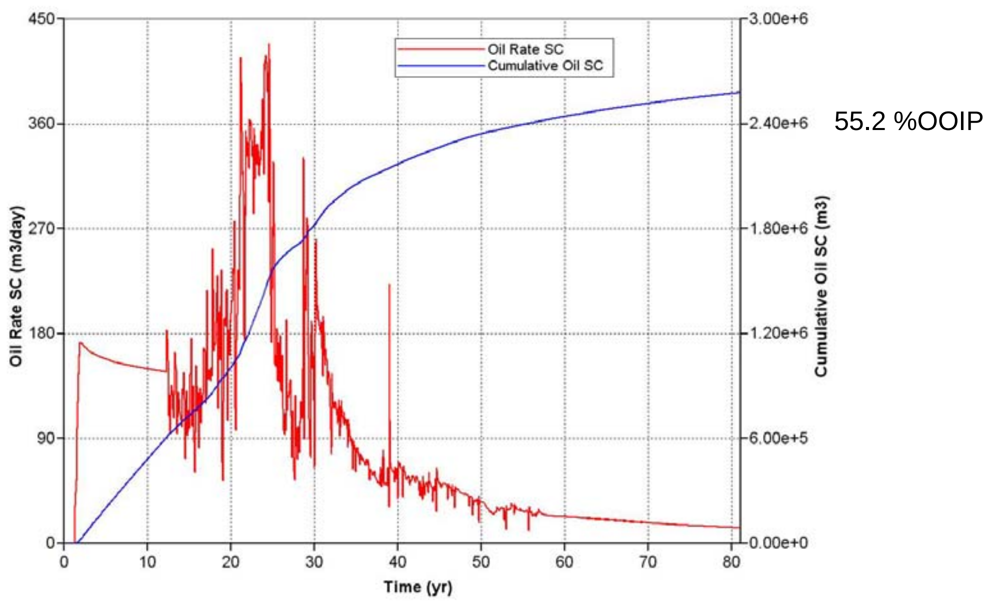


Figure 4.5.4.1: Base Case Oil Rate And Cumulative Production with existing BHP in producers (Note: 2007-01-01 corresponds to year 56 on the time scale)

4.5.5 CO_2 EOR Forecast

Forecasts were made for various CO_2 flooding scenarios using different "water alternating gas" (WAG) ratios and injection patterns. Results of an inverted nine-spot pattern are presented (Figure 4.5.5.1). Three wells (03-19, 09-19 and 11-19) were converted to injectors.

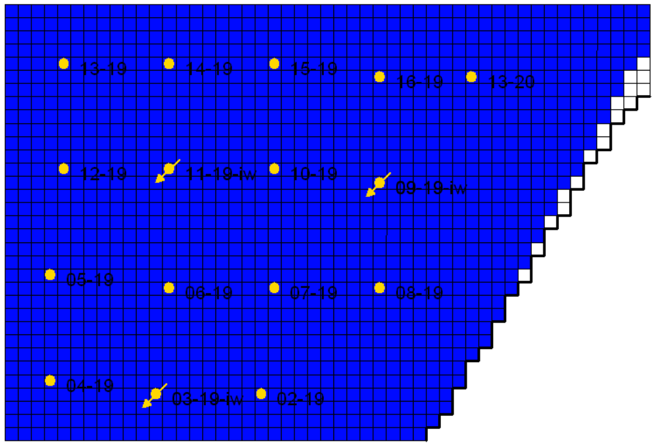


Figure 4.5.5.1: Inverted nine spot pattern used for CO_2 flood prediction

A total of 1 HCPV of CO_2 was injected at a W/G ratio of roughly 1:1 followed by an additional 2 HCPV of chase water following the CO_2 injection period (Figure 4.5.5.15) to give total CO_2 injection of 1 HCPV; total water injection of 3 HCPV. The forecast oil rate and cumulative production is shown in Figure 4.5.5.2.

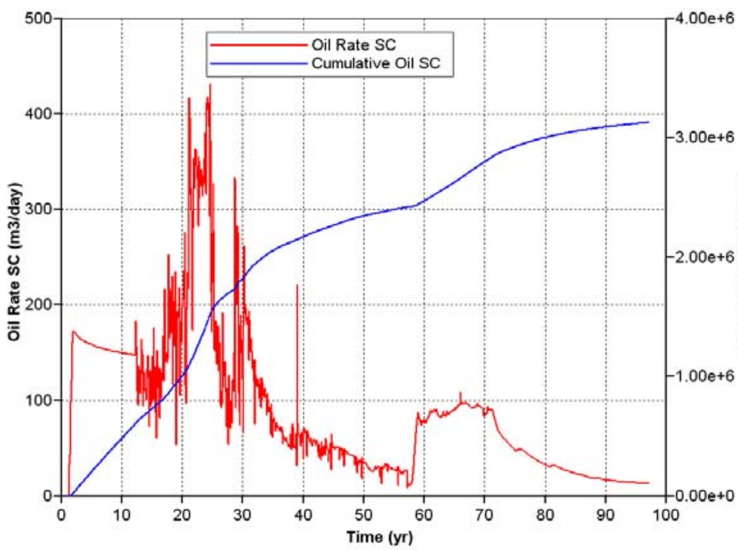


Figure 4.5.5.2: Oil Rate and cumulative oil recovery Inverted 9-spot with chase water. (Note: 2007-01-01 corresponds to year 56 on the time scale)

Evaluation of the preceding CO_2 flooding scenarios showed accumulation of CO_2 in upper parts of the model due to the low density of CO_2 at the temperature and pressure of the reservoir. At the reservoir temperature (34.4 C) and pressure (~7.2 MPa) the density of CO_2 is 268 kg/m^3, substantially less than that of the oil (845 kg/m^3). Te low density of CO_2 will preferentially cause the CO_2 to migrate to the top of the reef. This suggests that the EOR displacement process will tend to be horizontal rather than vertical. Further work is required to investigate the vertical displacement mechanism. The ARC Resources CO_2 pilot in the pool may provide additional insight.

4.5.6 Area Models

The Redwater Reef Model was used to derive geological parameters for conducting numerical simulation sensitivity studies designed to extend the results of the numerical simulation from the Redwater sector simulation area to the remainder of the pool. To derive the sensitivity study parameters, the Redwater Pool was divided into three sectors corresponding to the Reef Front, Back Reef and Lagoon. The location of these facies polygons is shown in Figure 4.5.6.1.

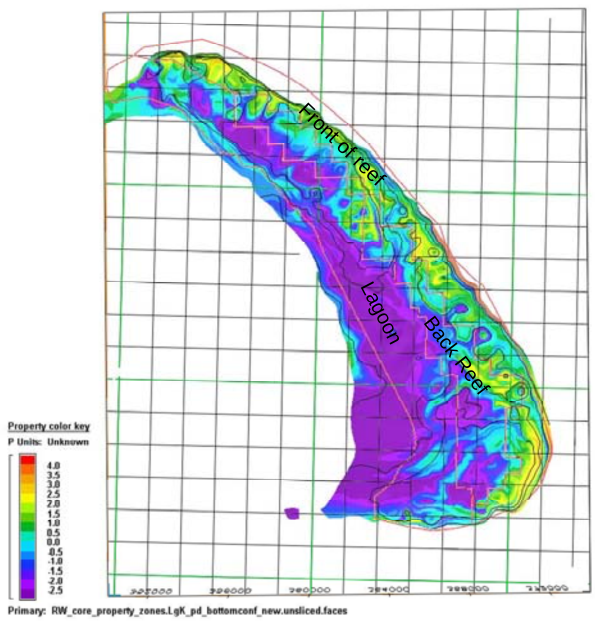


Figure 4.5.6.1: "Top View" of the Redwater Reef Model showing the Reef Front, Back Reef and Lagoon facies polygons (in red) and permeability of the uppermost model layer. Note the correspondence between areas of good reservoir quality and the Reef Front, and to a lesser degree with the Back Reef.

The Redwater sector model was modified by adjusting the k-h and k-ϕ ratios of the sector model to match the average geological parameters of the three areas The resulting area models were used to generate a base case waterflood and a WAG 1:1 CO_2 flood scenario for each area to feed into the development plan.

The CO_2 injection was started when the producing water cut reached a certain level. The water cut criterion was based on extrapolation of the area water-oil-ratio from the historical production behaviour of the wells in each area of interest to the year 2013, the date that it is anticipated the CO_2 flood would commence. The water cut criterion was calculated for each area from the water-oil-ratio expected in the year 2013, the assumed start of the CO_2 flood, as WC=WOR/(WOR+1). Table 4.5.6.1 provides the summary of the historical data. Table 4.5.6.2 summarizes the waterflood and WAG 1:1 CO_2 recoveries from the area model forecasts. Table 4.5.6.3 provides data on CO_2 utilization observed in the model forecasts.

Table 4.5.6.1: Actual Performance Data for Prospective EOR Areas – Redwater					
Area	Injectivity/well (m^3/d)	Productivity/well (m^3/d)	Extrapolated Water-Oil Ratio in 2013	Extrapolated Water Cut In 2013	WF Recovery to date million m^3
1 (fore reef)	5000	400	200	0.99503	35.7
2 (build-up)	2500	500	300	0.99668	67.3
3 (lagoon)	3000	200	150	0.99338	56.7

Table 4.5.6.2: Results of Redwater Area Model Forecasts						
Area	HCPV ($10^6 rm^3$)	OOIP ($10^6 sm^3$)	Oil Recovery at start of CO_2 injection ($10^6 sm^3$/%OOIP)	Oil Recovery Baseline Waterflood ($10^6 sm^3$/%OOIP)	Oil Recovery CO_2 WAG ($10^6 sm^3$/%OOIP)	Incremental CO_2 Recovery over Baseline Waterflood %OOIP
1 (fore reef)	5.913	5.407	2.97 / 54.9	3.11 / 57.5	3.24 / 59.9	2.4
2 (build-up)	7.412	6.779	3.83 / 56.5	3.92 / 57.8	4.14 / 61.1	3.3
3 (lagoon)	3.448	3.154	1.70/ 53.9	1.79 / 56.7	1.90 / 60.2	3.5

Table 4.5.6.3: CO_2 Utilization – Redwater Area Models						
Area	CO_2 Injected (HCPV)	CO_2 Produced (HCPV)	Gross CO_2 utilization t/m^3 oil	Net CO_2 utilization t/m^3 oil	Gross CO_2 utilization Mcf/bbl oil	Net CO_2 utilization Mcf/bbl oil
1 (fore reef)	1.01	0.687	12.0	3.55	36.1	10.7
2 (build-up)	0.998	0.629	7.92	2.48	23.8	7.5
3 (lagoon)	1.01	0.713	8.11	2.32	24.4	6.9

5. DEVELOPMENT PLANS FOR PROTOTYPES

Development plans were prepared for the five prototype pools using Vikor's "Pattern Development Model" (Appendix 1). Using existing wells and new wells where required, well patterns were prepared for each prototype pool to fully develop a CO_2 flood in the prototype pool. The Pattern Development Model is used to assess development scenarios by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns.

5.1 DEVELOPMENT PLAN COST FACTORS

Well cost factors for well drilling, completion and conversion for the prototype pools were developed by Silvertip Ventures. Unit cost factors for gas processing were derived from capital and operating cost estimates prepared by SNC Lavalin (SNC). SNC prepared two cases: a full produced gas recycle case with no separation of CO_2 from other produced gases and a recycle case in which CO_2 is separated from produced gases prior to reinjection. Pengrowth, the Judy Creek Gas Conservation System operator, provided input into the estimates. The SNC report is provided as Appendix 2.

5.2 DEVELOPMENT PLANS

5.2.1 Pembina Cardium with thief zone (conglomerate), North Pembina Cardium Unit 1

The prototype for Pembina with a thief zone utilized the better area of the North Pembina Cardium Unit #1 (NPCU#1). For the purpose of creating development plans, the North Pembina Cardium Unit has been divided into 8 areas (Figure 5.2.1.1). The areal breakdown, outlined in blue, is that used by ARC Resources. These areas have been further truncated, outlined in red, to include the "thief zone" area and to simplify the development plan calculations by bounding them with lines of injectors, so that there is no outflow of oil or CO_2 from the areas to be accounted for in the development plan.

Areas 4, 5 and 8 are the best parts of prospective EOR areas within NPCU/ PCU #20. In the development scenario presented here, Areas 1 & 7 were excluded because of low well injectivity/ productivity indicative of the lack of a thief zone and also to avoid the river.

The production forecast is based on fractional flow curves derived from model sensitivity studies representative of the six polygons in the development area for continued waterflood using current strategy to a WOR of 200 and CO_2 EOR at a WAG ratio of 2:1. The EOR project development plan used existing vertical wells on 32 ha (80 acre) per well spacing for injection into all zones and the existing vertical production wells completed in all zones plus new 600 m horizontal wells competed only in sand 4. The forecasts were utilized as developed by the simulation study **without** any risk factors.

The concept was that the area is productivity limited with restricted communication between sand 4 and the upper sand 5/6 and conglomerate. By injecting into all zones and limiting production from the sand 5/6 and conglomerate, pressure should be higher in the upper zone promoting injection into the higher oil saturation sand 4. In addition new horizontal water injection wells were drilled at the end of the on-trend

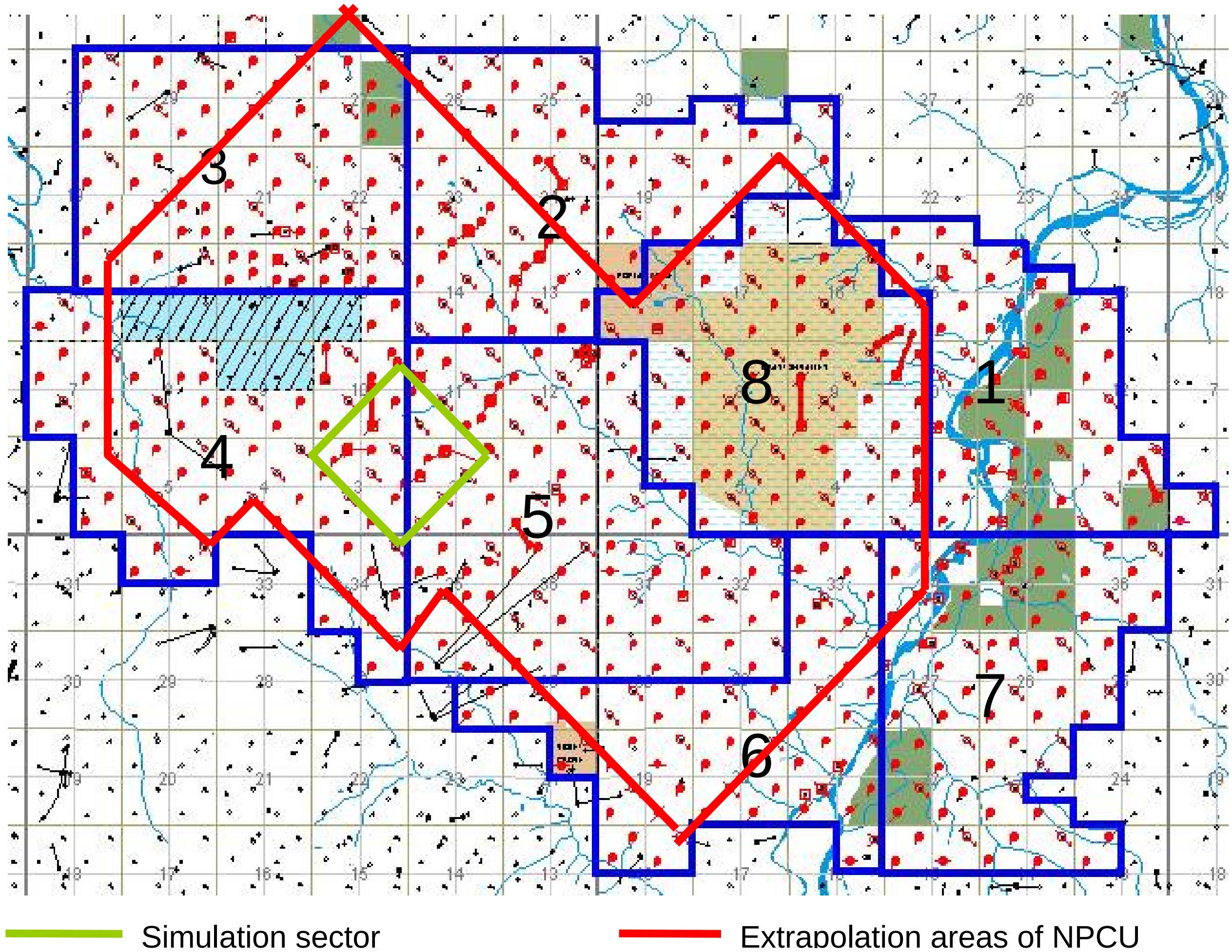


Figure 5.2.1.1: Pembina Cardium NPCU 1 and PCU 20 (blue hatched area). Analogue areas selected for extrapolation of simulation results and formulation of development scenarios are polygons formed by intersections of red lines and blue boundaries of ARC Resources Development Areas.

patterns to try to create a pressure "fence" to minimize loss of CO_2 from the patterns through natural fractures. Table 5.2.1.1 provides the parameters used in each area of the development plan, the injection strategy, predicted oil recovery and the total %HCPV of CO_2 and water, injected on a one-month 2:1 WAG cycle during WAG injection followed by chase water. The variation in recovery is because of the maturity and the quality of the different layers in the various areas compared to the area where the detailed history match and forecast was completed.

Figure 5.2.1.2 shows the development area used, how the 62 patterns were laid out and the location of the on trend fence water injection wells. The sector simulation area, outlined in black on Figure 5.2.1.2, has had the best historical performance in the Pembina Cardium.

Figure 5.2.1.3 shows the existing wells (black dots) and new 600 m horizontal wells (green lines) used to estimate the costs and injectivity/productivity. Most patterns have more than one injection well to accommodate the horizontal well geometry. The project utilized 171 existing vertical injection wells and 22 new drilled horizontal water fence wells for injection into all layers. One hundred and sixteen new horizontal production wells and 188 existing production wells are utilized. The less productive layers in all wells would be stimulated to enhance processing rates. The forecast assumes all wells stay on production for the life of the patterns.

Table 5.2.1.1 Pembina Cardium Thief Zone CO_2 EOR Development Plan Parameters & Performance

Area	Hz. Well Productivity	OOIP	% HCPV Injected			Predicted Recovery % OOIP	
	(m^3/d)	e^3m^3	CO_2	Total	WF	Base W/F	EOR
2	77	9,104	52%	251%	251%	8.6%	18.1%
3	31	6,232	51%	251%	251%	13.3%	17.9%
4	96	10,520	51%	251%	251%	9.2%	14.0%
5	37	23,276	50%	251%	251%	5.3%	18.0%
6	20	3,962	49%	251%	251%	11.6%	9.3%
8	20	17,191	51%	251%	251%	10.0%	17.6%
total		70,285					
total million barrels		442					

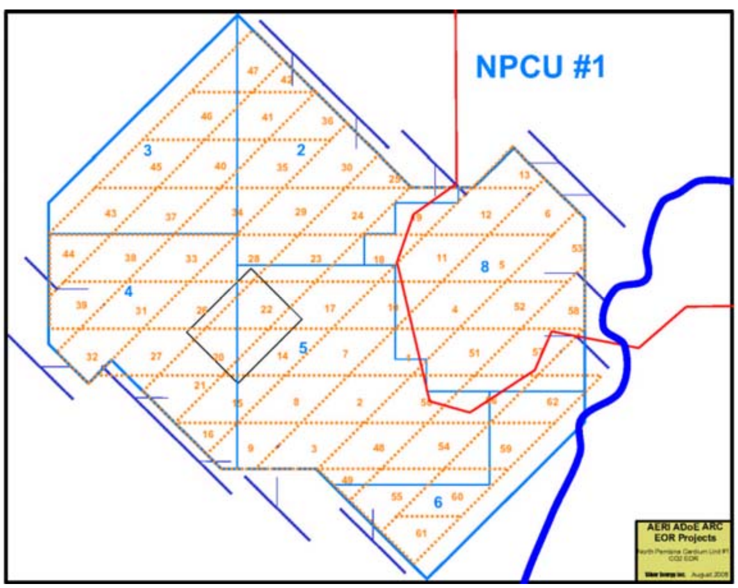


Figure 5.2.1.2: Layout of patterns for development plan showing the fence water injectors

Figure 5.2.1.4 shows a new gathering system (in black) that goes to all production wells and CO_2 injection lines (in red) to all WAG injectors. It was assumed that the existing waterflood system was adequate. A new gathering system was installed because of potential higher operating pressure, corrosion and desire to produce low CO_2 concentration wells to gas plant rather than dilute produced CO_2.

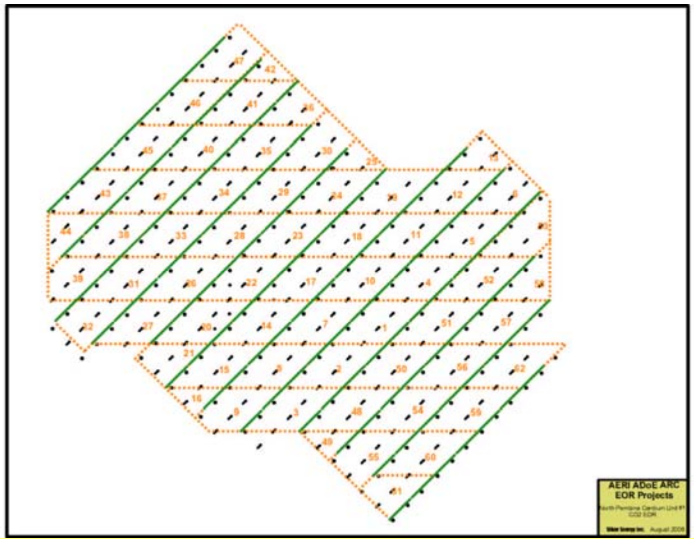


Figure 5.2.1.3: Development plan well layout, existing wells (black), new horizontal wells (green)

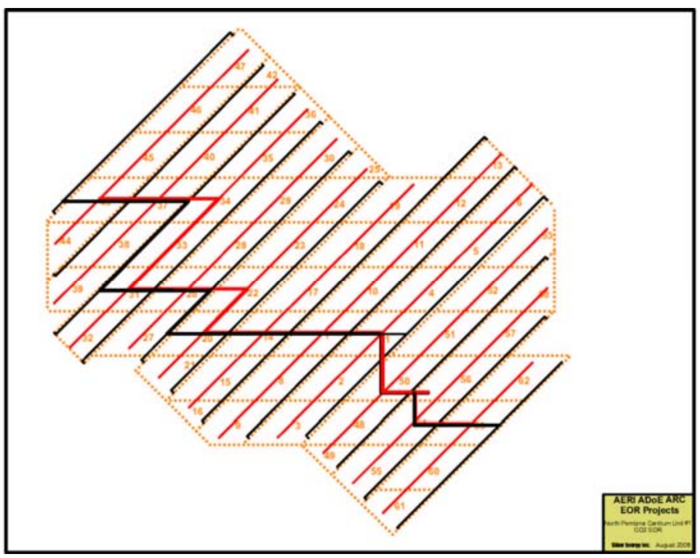


Figure 5.2.1.4: New gathering system used in development plan. Black shows new lines to all production wells; red shows CO_2 lines to CO_2 injectors.

The full area production forecast is generated using fractional flow curves derived from the simulation of the 6 areas in the development area for continued waterflood using current strategy to a WOR of 200 and CO_2 EOR at a WAG of 2:1. The forecast for the full areas limited the total injection to 250% HCPV. The CO_2 injection forecast was that required to meet simulation prediction. In order to maximize CO_2 storage all produced CO_2 should be reinjected. This would also increase oil recovery.

CO_2 EOR recovery reported in Table 5.2.1.1 is above the Base Case waterflood that used only the existing wells. The variation in recovery is because of the maturity and the differing quality of the layers in the different areas. The Development Plan limited injection to an incremental 250% HCPV. After the start of CO_2 EOR, it took 70 years to inject 250% HCPV. Waterflood oil is accelerated in the EOR case compared to the base case waterflood production.

Table 5.2.1.2 summarizes some of the key results for both the Base Case Waterflood and the CO_2 EOR generated from the study. Predicted CO_2 EOR incremental oil recovery is optimistic. Six of the patterns had not finished chase water injected in the 75 year forecast.

Table 5.2.1.2 Pembina Cardium Thief Zone CO_2 EOR
Summary of Results

OOIP	66.9 e^6m^3	421.0 10^6 Bbl		
Oil Production				
Base Case	5,576 e^3m^3	35,070 10^3 Bbl	8.3%	estimate
CO_2 EOR	11,209 e^3m^3	70,501 10^3 Bbl	16.7%	"T" Factor
Total	16,785 e^3m^3	105,571 10^3 Bbl	25.1%	0.67
Natural Gas Sales		0 e^6m^3	0.0 bcf	
CO_2 Injection	36,868 Gg	19,809 e^6m^3	703.1 bcf	50.3%
CO_2 Purchased	10,439 Gg	5,609 e^6m^3	199.1 bcf	14.2%
CO_2 Production	31,816 Gg	17,095 e^6m^3	606.8 bcf	43.4%
WAG Ratio	2:1	Maximum Source CO_2	13 years	
Maximum purchased CO_2		1,200 tonne/day	22.9 mcf/d	
Maximum injected CO_2		2,978 tonne/day	56.8 mcf/d	
CO_2 Utilization Factor	(CO_2 EOR oil only)			
Gross	3.29 t/m^3	9.97 mcf/Bbl		
Net	0.93 t/m^3	2.82 mcf/Bbl		
Water Injection			% HCPV	
Chase & WF	97,013 e^3m^3	610,196 10^3 Bbl	105.9%	
WAG	92,128 e^3m^3	579,465 10^3 Bbl	100.6%	

Summary

The development plan shows that the NPCU enhanced recovery by CO_2 will recover significant incremental oil with the given assumptions. Important features of the development plan results are:

- CO_2 incremental oil for the development area is 16.7% of original-oil-in-place. This is approximately 11.2 million m^3 (70.5 million barrels) incremental recovery from the 66.9 million m^3 (421 million barrels) of original-oil-in-place in the development area.
- In 75 years 5.6 e^6m^3 of waterflood oil is also produced; without the development 4.8 e^6m^3 of Base Case waterflood oil would be produced in 75 years.

- Gross CO_2 utilization factor was 3.29 tonne/m^3 (10.0 mcf/bbl) of incremental oil; net utilization factor was 0.93 tonne/m^3 (2.82 mcf/bbl).
- Source CO_2 is required for 32 years, 13 years at maximum rate of 1,200 tonne per day.
- CO_2 injection is that required to meet the forecast; if all produced CO_2 were injected, 10.4 million tonnes would be stored. Considering that this is best area of Pembina, this is not a large amount of stored CO_2.

Risk Factors

A number of risk factors exist:

1. In the numerical simulation of NPCU, production from the top conglomerate zone was controlled in order to achieve better sweep and recovery from the lower zones (which contain the bulk of the OOIP). The ability to control the flow of CO_2 into the conglomerate is uncertain and introduces risk that the field may not perform as predicted by the simulation and development plan. In addition, the integrity of the shale and impacts of the vertical fractured wells are unknowns. These factors may be mitigated by improvements in horizontal well drilling and fracturing technology in the years preceding the start of the CO_2 flood. At this stage the highest probability that could be assigned is an 80% chance of success with this approach. The ARC Resources CO_2 pilot in Pembina may help to assess this risk.
2. Can the productivity of the horizontal wells running in the off trend direction be achieved and sustained and fracturing into the upper zones be prevented? Once significant volumes of CO_2 are produced, well bottom hole producing pressure must be kept high to minimize Joule-Thompson cooling, further impacting productivity (80% chance of success at the most).
3. Processing rate for injection/production in much of the Pembina area is low. The risk is that there may not be enough productivity and injectivity in any but the best areas of Pembina to complete the project in a reasonable time. The numerical simulation required significant time to inject the required volumes of CO_2. That can significantly impact project economics.
4. Can we flood off trend from the line drives and contain the CO_2 in the pattern with the fence wells (80% chance of success at the most).

Even if each of the above has an optimistic 80% chance of success, overall chance is only about 50%. Perhaps other mitigation procedures such as field piloting, testing of long horizontal wells in Sand 4 and successfully stimulating with multiple fractures, and staging of the project can help further reduce technical risks.

5.2.2 Pembina without thief zone (no conglomerate)

The prototype for Pembina Cardium without a thief zone utilized the area surrounding the Penn West CO_2 Pilot in the "A" Lease (Area 2) and the better portion of Cyn Pem Unit #3 (Area 1). The area covered 8,430 ha; see Table 5.2.2.1 for other parameters used for Cyn Pem Unit #3 (Area 1) and "A" Lease (Area 2). The production forecast for both Base Case waterflood and CO_2 EOR are based on black oil modelling using Eclipse 100 simulator. The forecasts were utilized as developed **without** any risk factors; the CO_2 EOR recovery is realistic. The low WOR after 50 years of waterflood operation illustrates the very low processing rate and significant remaining oil recovery is expected, although the predicted 23.9% may be optimistic.

Table 5.2.2.1 Pembina Cardium No Thief Zone CO_2 EOR

Development Plan Parameters								**Area Performance**				
Area	Injectivity per well	Productivity/well		OOIP	Predict WOR	Recovery to date		% HCPV Inject			Recovery % OOIP	
		vertical	horizontal									
	(Rm^3/d)	(Rm^3/d)		e^{3}m^3	2013	e^{3}m^3	OOIP	CO_2	Total	WF	Base	EOR
1	35	2	50	29,245	1.9	5,690	19.5%	99.1%	300%	300%	23.9%	13.0%
2	50	4	75	30,482	4.0	6,559	23.1%	99.1%	300%	300%	23.9%	13.0%
Total				59,727		12,249	21.2%					
total millions barrels				375.7		77.0						

The EOR project was developed as a line drive with vertical injection wells on 16 ha (40 acre) per well spacing for injection into all zones and new 1,200 m horizontal wells between the injectors, completed in the middle of sand 4 with fractures to the other layers. Because the area is very productivity limited the Development Plan utilized infill drilling to tight spacing (20 acre spacing per well). In addition, new horizontal water injection wells were drilled at the end of the on trend patterns to try to create a pressure "fence" to minimize loss of CO_2 from the patterns through natural fractures. All of the trend patterns are developed together to use the fence wells before adjacent off trend patterns are developed.

The EOR recovery project benefits from two factors, a very significant acceleration of oil production and good incremental recovery from CO_2 injection. The modelling indicated that almost 1,000 years of operation would be required to reach the economic limit with current wells; only 8.4% HCPV of water was injected in 75 years in the Base Case waterflood. A very large amount of capital is involved in developing the area to achieve an acceptable processing rate; the development plan was not optimized.

Figure 5.2.2.1 shows the development area used and the 87 patterns that were laid out, as well as the on-trend fence water injection wells. Area 1 is in the northwest in Twp 49 Rge 10 (Cyn Pem Unit #3) and Area 2 is in the southeast in Twp 48 Rge 9 and includes part of the "A" Lease. The OOIP was determined from the Purvis and Bober (1979) analysis of Pembina. The area was measured and the OOIP per ha calculated to determine the OOIP for each pattern. The simulation area is outlined in black on Figure 5.2.2.1 and includes the Penn West CO_2 Pilot in the "A" Lease.

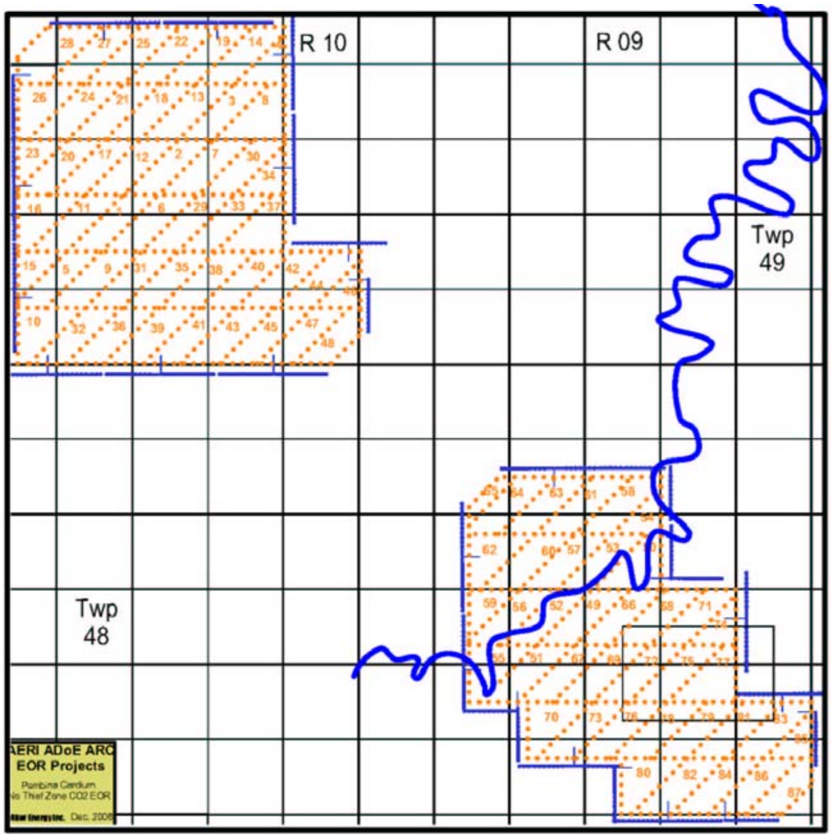


Figure 5.2.2.1: Patterns used in Pembina without thief zone. Simulation area is outlined in black (lower right) and includes the Penn West CO_2 Pilot in the "A" Lease.

The predicted oil recovery remaining under Base Case waterflood and the oil recovery above Base Case from CO_2 EOR is shown on Table 5.2.2.1. In the Base Case waterflood only the existing wells were utilized and less than 10% OOIP would be produced in 100 years. With the infill, stimulation and horizontal wells, the development occurs over about 60 years. The estimated 23.9% remaining reserves are accelerated, in addition to the 13% of EOR oil production, and appear with the EOR recovery.

The full area production forecast was generated using fractional flow curves derived from the modeling of the "A" Lease area. A history match and continued waterflood (Base Case) was obtained for the full model area. However computational limitations prevented prediction runs with infill and horizontal wells to obtain the CO_2 EOR prediction. Instead a sub area containing 6 vertical injection wells on 16 ha (40 acre) spacing surrounding a single 1,000 m horizontal well was used. Both a waterflood run to over 300% HCPV injection and a run with 99% HCPV of CO_2 at a WAG ratio of 1:1 followed by more than 100% HCPV of chase water injection were completed. The Base Case waterflood forecast was determined from the full model area prediction and the incremental CO_2 EOR prediction was developed by subtracting the waterflood prediction (for the same time period as the CO_2 EOR) from the CO_2 EOR model prediction. The forecast for the full areas limited the total injection to 300% HCPV. The CO_2 injected, produced and stored are shown on Table 5.2.2.2. The CO_2 injection forecast is that required to meet simulation prediction. In order to maximize CO_2 storage all produced CO_2 should be reinjected. This would also increase oil recovery.

Figure 5.2.2.2 shows the existing wells in black and new horizontal production wells (green lines) and new vertical injectors in green for a portion of Area 1. Note that most patterns have six injection and two dual leg horizontal production wells. The EOR injectors include 176 existing vertical production wells, 180 new vertical injection wells and 136 existing vertical injection wells. The 45 new horizontal water fence injection wells are shown in blue on Figure 5.2.2.1. All production wells are new horizontal wells (25 single leg, 600 m wells and 155 dual leg, 1,200 m wells). It was assumed that all layers in all wells would be stimulated to enhance processing rate. The forecast assumes all wells stay on production for the life of the patterns at rates from analysis of historical well performance in each area. The Base Case waterflood uses only the existing vertical wells.

Figure 5.2.2.3 shows the complete new gathering system (in black) that goes to all wells and water and CO_2 injection lines (in red) to all WAG injectors. A complete new gathering system was included in the development plan because of potential higher operating pressure, corrosion in existing system and desire to produce low CO_2 concentration wells to the gas plant rather than dilute produced CO_2. The much higher production rates from the fractured horizontal wells will also require new well test facilities. Because of the age, number of conversions and new wells it is assumed that the existing waterflood system is inadequate so new water injection lines were installed. The system was laid out to allow installation of the gathering and injection lines in a common ditch.

Table 5.2.2.2 summarizes some of the key results for both the Base Case Waterflood and the CO_2 EOR Project generated from the study. Predicted oil recovery may be optimistic. CO_2 EOR incremental oil recovery of 7.7 e^6m^3 or 12.8% OOIP is forecast by the simulation with the injection of 68.5 million tonnes of CO_2, 99.1% HCPV of CO_2 at a WAG of 1:1 followed by chase water. All of the patterns had finished chase water injection in the 65 year forecast. In 65 years 13.9 e^6m^3 of waterflood oil is also produced; without the development only 5 e^6m^3 of Base Case waterflood oil would be produced in 75 years. Source CO_2 is required for 29 years, 22 years at maximum rate of 1,500 tonne per day. CO_2 injection shown is that required to meet the forecast. However, if all produced CO_2 were injected, then 13.9 million tonnes would be stored. Net CO_2 utilization is 1.8 tonne/m^3 (5.5 mcf/Bbl), gross CO_2 utilization is poor at 8.9 tonne/m^3 (27 mcf/Bbl), based only on the CO_2 EOR oil.

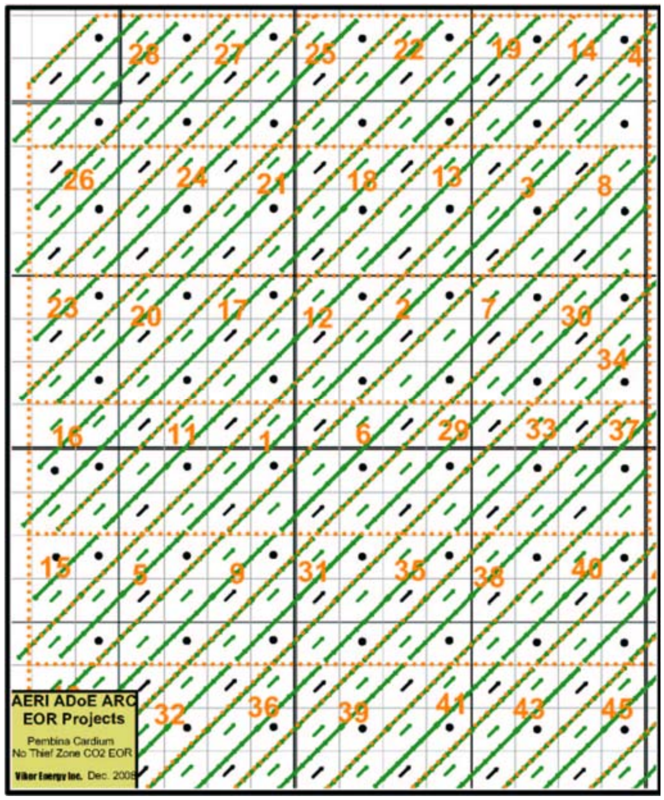


Figure 5.2.2.2: Pembina Cardium without thief zone - existing wells in black and new horizontal production wells (green lines) and new vertical injectors in green for a portion of Area 1.

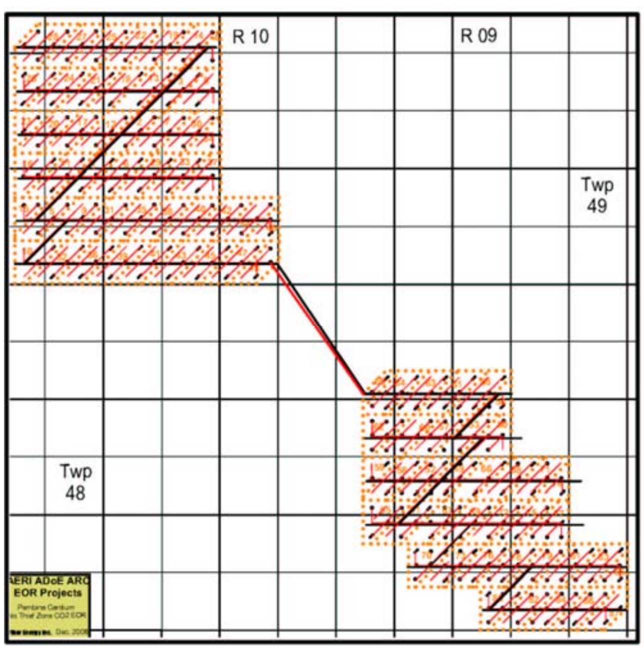


Figure 5.2.2.3: Pembina Cardium without thief zone – Injection and Gathering systems

Table 5.2.2.2 Pembina Cardium No Thief Zone CO_2 EOR

Summary of Results

Pembina Cardium No Thief Zone CO_2 EOR

OOIP	59.7	e^6m^3	375.7	10^6 Bbl				
Oil Production								
Base Case	13,907	e^3m^3	87,472	10^3 Bbl	23.3%		estimate	
CO_2 EOR	7,673	e^3m^3	48,261	10^3 Bbl	12.8%		"T" Factor	
Total	21,580	e^3m^3	135,734	10^3 Bbl	36.1%		0.36	
Natural Gas Sales			62	e^6m^3	2.2	bcf		
CO_2 Injection	68,503	Gg	36,807	e^6m^3	1,306.4	bcf		99.1%
CO_2 Purchased	13,918	Gg	7,478	e^6m^3	265.4	bcf		20.1%
CO_2 Production	59,434	Gg	31,934	e^6m^3	1,133.5	bcf		86.0%
WAG Ratio	1:1		Maximum Source CO_2		22	years		
Maximum purchased CO_2			1,500	tonne/day	28.6	mcf/d		
Maximum injected CO_2			7,462	tonne/day	142.3	mcf/d		
CO_2 Utilization Factor	(CO_2 EOR oil only)							
Gross	8.93	t/m^3	27.07	mcf/Bbl				
Net	1.81	t/m^3	5.50	mcf/Bbl				
Water Injection					% HCPV			
Chase & WF	87,378	e^3m^3	549,589	10^3 Bbl	106.9%			
WAG	80,975	e^3m^3	509,319	10^3 Bbl	99.1%			

Risk Factors

The parts of the "A" Lease and the better portion of the Cyn Pem Unit #3 analyzed here are the best parts of these areas in the Pembina Cardium.

The most significant technical risks include:

1) The impact of the natural fractures on containing the flood in the patterns and zones is a very large geological risk. Will the flood move off trend from the line drive and the fence wells contain the CO_2 in the pattern?
2) Can the productivity of the horizontal wells running in the off trend direction be achieved and sustained?
3) Can the flow be forced to the off trend wells with good vertical conformance?
4) Is the acceleration of the remaining reserves and the CO_2 EOR potential sufficient to support the huge capital expenditure required?
5) Will the productivity and injectivity be adequate to complete the project in a reasonable length of time?

6) Operating pressure is very high so cap rock and well bore integrity is critical. Also the high pressure will complicate well operation and workovers.

7) Can wax deposition in the reservoir near production wells caused by cooling from the expansion of CO_2 be avoided? Figure 5.2.2.4 shows a rough calculation of the potential isenthalpic cooling, assuming the pressure drop occurs in a 10 m radius of the wellbore.

An extended field pilot test will be necessary to develop strategies to mitigate these risks.

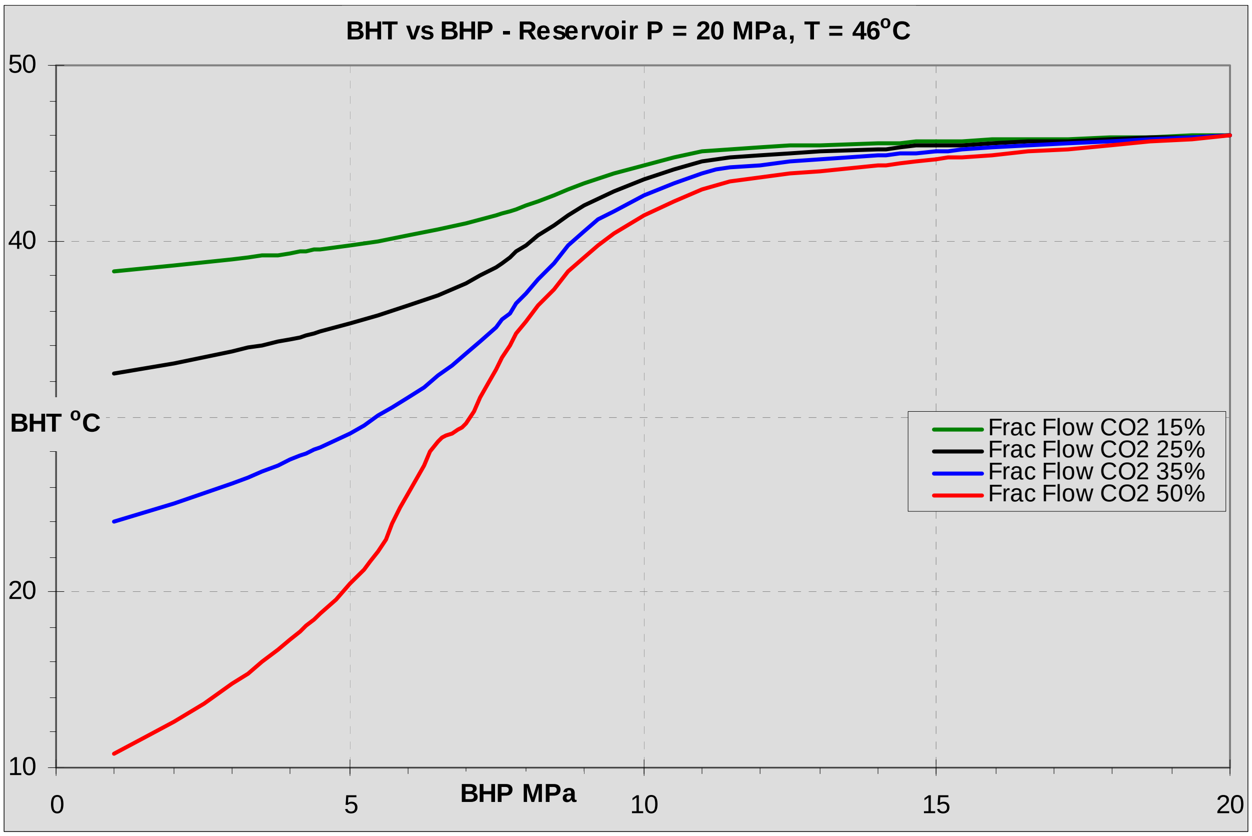


Figure 5.2.2.4: Calculated isenthalpic cooling in the near wellbore region due to expansion of CO_2

5.2.3 Beaverhill Lake Waterflooded Areas

An area around the edge of the reef buildup in the Swan Hills Beaverhill Lake A&B Pool that has not had hydrocarbon miscible solvent flood injection was chosen for preparation of development plans for CO_2 EOR in Waterflood Areas (WFA) of Beaverhill Lake Pools. The area covered 2,724 ha and contained 43.55 e^6m^3 (274 million barrels) of OOIP; production to date equals 18.62 e^6m^3 (117 million barrels). The WFA was divided into 4 regions with unique geological and waterflood performance.

Sensitivity studies were performed with the Judy Creek model using the characteristics of the four WFAs to determine ranges of expected oil recovery from subsequent CO_2 flooding in these waterflooded regions. Relevant performance characteristics are provided in Table 5.2.3.1. Expected water-oil-ratios of each area in 2013 were estimated and the prediction model runs commenced at the time that the respective water-oil-ratios were attained in the simulation history or forecast. Historical injectivity and productivity is shown for each area. Productivity for edge wells and wells to be shared with the CO_2 EOR in the Solvent Flood Area (SFA) were proportionately reduced. The OOIP and area of each WFA were provided by Divestco and used to calculate the OOIP per ha; the OOIP for each pattern was calculated by multiplying pattern area by the OOIP per ha for the WFA containing the pattern. The individual WFA recovery is distorted because oil production has not been prorated between patterns where a production well is common to two Areas and prior waterflood and solvent flood operations displaced oil to different Areas. This is evidenced by the variation in oil recovery in Table 5.2.3.1.

Table 5.2.3.1 BHL CO_2 EOR WFA

Development Plan Parameters							Area Performance				
Area	Injectivity per well	Productivity per well	OOIP	Predict WOR	Recovery to date		% HCPV Inject			Recovery % OOIP	
	(Rm^3/d)	(m^3/d)	e^3m^3	2013	e^3m^3	OOIP	CO_2	Total	WF	Base	EOR
WFA 1	600	350	9,339	50.0	282	3.0%	75.7%	251%	251%	4.2%	18.1%
WFA 2	1,000	300	13,000	50.0	3,670	28.2%	68.3%	240%	240%	3.8%	20.1%
WFA 3	400	300	7,342	200.0	1,762	24.0%	89.6%	172%	0%	0.0%	20.4%
WFA 4	1,000	250	13,866	50.0	12,888	92.9%	88.2%	251%	251%	4.4%	26.5%
Total			43,547		18,602	42.7%					
total millions barrels			273.9		117.0						

The predicted oil recovery remaining under Base Case waterflood and CO_2 EOR by area is also shown on Table 5.2.3.1. The variation in recovery may be because of current maturity of the different Areas and volume of CO_2 injected. In the Base Case waterflood only the existing wells were utilized therefore the processing rate is lower than in the CO_2 EOR case where additional wells are utilized. Some of the production is because of the infill wells; however, it is assumed that the infill wells would not be drilled without the CO_2 EOR. As Area 3 is expected to have reached its economic limit of a WOR equal to 200 by the time CO_2 EOR would be initiated, no Base Case waterflood reserves are expected. A problem occurred in the simulation for Area 3 and "Chase Water" injection following the WAG process would not run so the case was terminated without it.

See Figure 4.3.6.1 for the development area used and the 40 patterns layout. It also shows the existing wells (black), wells drilled since 2001 (red) and new wells (gold) used to estimate the costs and injectivity/productivity for the patterns.

Figure 5.2.3.1 shows the complete new gathering system (black) that goes to all wells and all new CO_2 and water injection lines (red) to all WAG injectors. Because of the number of new injection wells, and system age a new water injection system was used for the EOR project. A complete new gathering system was installed because of potential higher operating pressure, corrosion in existing system and desire to produce low CO_2 concentration wells to gas plant rather than dilute produced CO_2.

The EOR project was developed using, where possible, inverted 5 spot patterns on 32 ha (80 acre) per well spacing and required 10 existing injection wells and 30 converted production wells for injection into all layers. The inverted 5 spot patterns on 32 ha (80 acre) per well spacing are consistent with recent development. 22 new wells and 54 existing production wells were used for production. It was assumed that less productive layers in all wells would be stimulated to enhance processing rate when most productive layers are shut in. The forecast assumes all wells stay on production for the life of the patterns that they service at rates as determined from analysis of historical well performance in each area.

The production forecast is based on fractional flow curves derived from the modeling of the 4 areas in the development area for continued waterflood using current strategy to a WOR of 200 and CO_2 EOR at a WAG of 1:1. Table 5.2.3.1 shows the total %HCPV of CO_2 and water, injected on a one month cycle during WAG injection followed by chase water. The forecast for the full areas limited the total injection of CO_2 and water to 250% HCPV. The CO_2 injected, produced and stored are shown on Table 5.2.3.2. Waterflood oil in the EOR case is accelerated compared to the base case waterflood production. The CO_2 injection forecast is that required to meet simulation prediction. In order to maximize CO_2 storage all produced CO_2 should be reinjected. This might also increase oil recovery.

Table 5.2.3.2 summarizes some of the key results for both the Base Case Waterflood and the CO_2 EOR Project generated from the study. Predicted CO_2 EOR incremental oil recovery may be optimistic. CO_2 EOR incremental oil recovery of almost 9.5 e^6m^3 or 21.8% OOIP is forecast by the simulation with the injection of almost 40 million tonnes of CO_2, 79% HCPV of CO_2 at a WAG of 1:1 followed by chase water. In 54 years 1.5 e^6m^3 of waterflood oil is also produced, without the development 1.2 e^6m^3 of Base Case waterflood oil would be produced in 75 years. Source CO_2 is required for 24 years, 13 years at maximum rate of 2,000 tonne per day. CO_2 storage is almost 6.7 million tonnes, less than 20% of the injected CO_2. CO_2 injection shown is that required to meet the forecast. If all produced CO_2 were injected, then

12.5 million tonnes would be stored. Net CO_2 utilization is excellent at 1.31 tonne/m^3 (4 mcf/Bbl). Gross CO_2 utilization is good at 4.21 tonne/m^3 (12.8 mcf/Bbl).

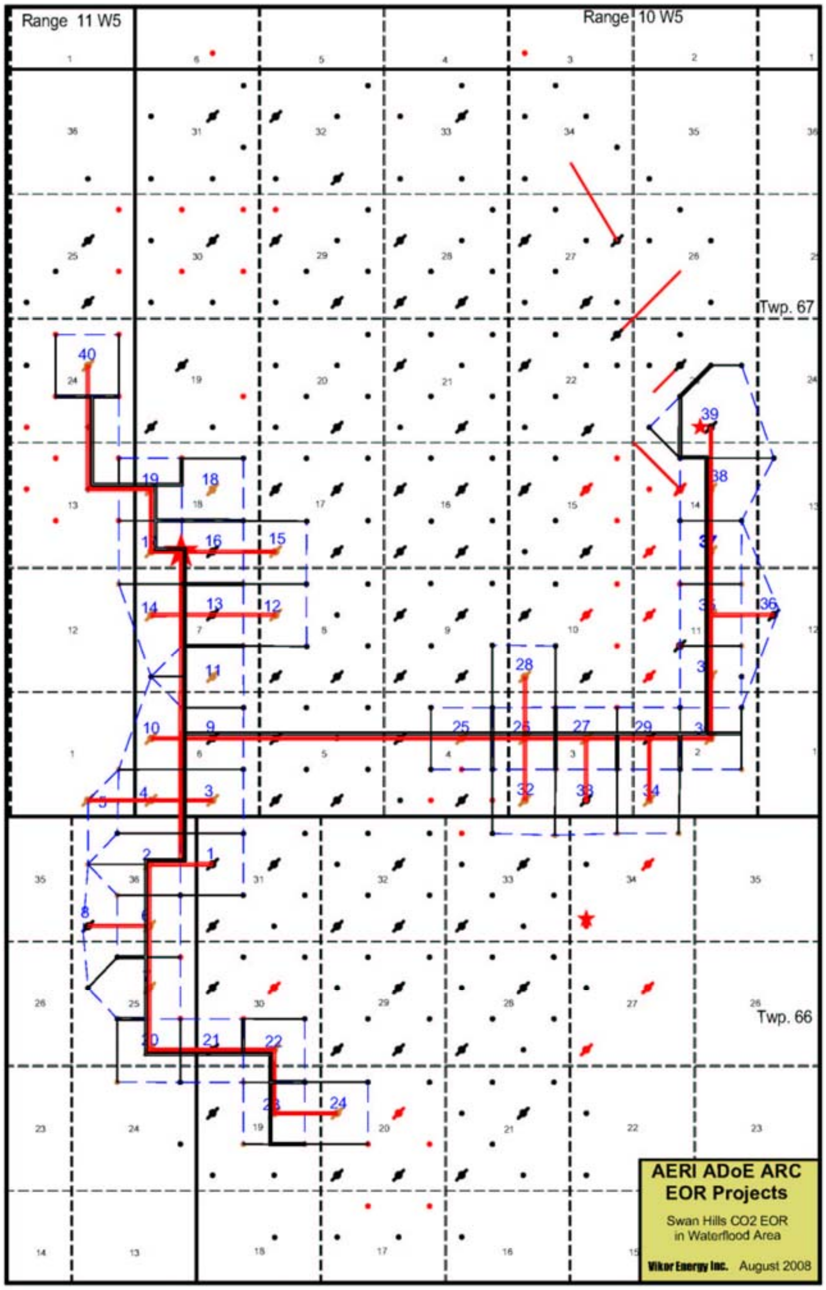


Figure 5.2.3.1: Map of Swan Hills pool showing new gathering system (black) to all wells and new CO_2 and water injection lines (red) to all WAG injectors used in development plan.

Table 5.2.3.2 BHL CO_2 EOR WFA

Summary of Results

OOIP	43.5	e^6m^3	273.9	10^6 Bbl			
Oil Production							
Base Case	1,518	e^3m^3	9,548	10^3 Bbl	3.5%		estimate
CO_2 EOR	9,486	e^3m^3	59,665	10^3 Bbl	21.8%		"T" Factor
Total	11,004	e^3m^3	69,213	10^3 Bbl	25.3%		0.86
Natural Gas Sales			1,255	e^6m^3	44.5	bcf	
CO_2 Injection	39,912	Gg	21,445	e^6m^3	761.2	bcf	79.3%
CO_2 Purchased	12,463	Gg	6,696	e^6m^3	237.7	bcf	24.8%
CO_2 Production	33,224	Gg	17,851	e^6m^3	633.6	bcf	66.0%
WAG Ratio	1:1		Maximum Source CO_2		13	years	
Maximum purchased CO_2			2,000	Mg/d	38.1	mmcf/d	
Maximum injected CO_2			4,993	Mg/d	95.2	mmcf/d	
CO_2 Utilization Factor		(CO_2 EOR oil only)					
Gross	4.21	t/m^3	12.76	mcf/Bbl			
Net	1.31	t/m^3	3.98	mcf/Bbl			
Water Injection					% HCPV		
Chase & WF	55.6	e^6m^3	349.6	10^6 Bbl	85.0%		
WAG	51.9	e^6m^3	326.4	10^6 Bbl	79.3%		

Risks Factors

The most significant technical risks include:

1. Prior waterflood and solvent flood operations have likely displaced oil in the reef making oil saturation when the CO_2 EOR is initiated difficult to predict. The wide variation in oil recovery in Table 5.2.3.1 may be a result of this.
2. Simulation predictions are very complex and many simplifying assumptions must be made. In this case, performance of all of the areas was not history matched, consequently prediction is less reliable.
3. The operation would need to be integrated with the larger solvent flood area that borders much of the waterflood area.

5.2.4 Beaverhill Lake Solvent Flooded Areas

The area of the reef build-up in the Swan Hills Beaverhill Lake A&B Pool that previously had hydrocarbon miscible solvent flood injection was chosen as the prototype for CO_2 EOR in Solvent Flood Areas (SFA) of Beaverhill Lake Pools. The area covered 7,736.5 ha and contained 149.4 e^6m^3 (940 million barrels) of OOIP; production to date (see Table 5.2.4.1) equals 81.06 e^6m^3 (510 million barrels).

Table 5.2.4.1 Development Plan Parameters

Area	Inject / well	Prod /well	OOIP	Predict WOR	Recovery to date	
	(Rm^3/d)		e^3m^3	2013	e^3m^3	OOIP
SFA 1	500	250	34,567	30.0	17,375	50.3%
SFA 2	500	200	55,625	50.0	29,578	53.2%
SFA 3	1,000	300	17,664	50.0	10,990	62.2%
SFA 6	500	400	15,545	100.0	7,096	45.7%
SFA 7	700	350	26,034	200.0	16,021	61.5%
Total			149,435		81,061	54.2%
total millions barrels			939.9		509.9	

Table 5.2.4.2 BHL CO_2 EOR SFA Area Performance

Area	% HCPV Inject				Predicted Recovery % OOIP					
			Base Case	history	total with CO_2		Base Case		CO_2 EOR	
	CO_2	Total		HCMS	Oil	HCMS	Oil	HCMS	Oil	HCMS
SFA 1	40%	224%	115%	15%	28.3%	16.4%	6.8%	2.9%	3.1%	2.3%
SFA 2	34%	205%	9%	6%	27.5%	7.9%	8.0%	1.0%	3.0%	2.4%
SFA 3	47%	185%	0%	2%	27.0%	3.7%	9.0%	0.5%	2.7%	2.1%
SFA 6	41%	83%	0%	2%	23.5%	3.2%	6.1%	0.4%	2.1%	1.6%
SFA 7	34%	137%	0%	14%	26.3%	15.3%	7.6%	2.7%	2.9%	1.9%

See Figure 4.4.6.2 for the development area used and the 100 inverted 5 spot patterns on 32 ha (80 acre) per well spacing. The spacing is consistent with recent development. The forecast assumes all wells stay on production for the life of the patterns that they service at rates as determined by ARC from analysis of historical well performance in each Area. Seventy-one existing injection wells, 27 converted production wells and 2 new wells were used for injection into all layers in the development plan scenario.

Figure 5.2.4.1 shows the existing wells (black), wells drilled since 2001 (red) and new wells (gold) used to estimate injectivity/productivity for the patterns. The predicted oil and hydrocarbon miscible solvent (HCMS) recovery remaining under Base Case and CO_2 EOR, by area are shown on Table 5.2.4.2. Significant difficulty was experienced in the simulation of the Area Models. It was very difficult to maintain reservoir pressure above MMP using expected production rates; therefore, productivity was constrained. Consequently the WOR at start of the CO_2 EOR was much lower than anticipated in the field. In spite of the precautions taken the reservoir pressure in the simulations dropped during CO_2 injection and miscibility may not have been maintained, especially in Area 2, reducing recovery. The boundary wells used for history matching were shut in during the prediction cases. The lower number of injectors prevented achieving the desired WOR value within a reasonable time. In Area 6 the model would not allow Chase Water resulting in lower recovery in this area.

The HCMS and CO_2 reservoir volume factors are very close in the simulation (CO_2 should be 50% heavier in the reservoir) and contributes to low oil recovery in the model. Predicting the volume of HCMS recovered is difficult because the composition of both produced oil and gas changes significantly with time. Using the simple approach of deducting initial solution GOR from the hydrocarbon gas produced to determine the solvent recovery is shown on Table 5.2.4.2. However more HCMS was produced then injected because of light ends extracted from the oil. The total weight percent of produced HCMS calculated as 88.5% and 94.8% of injected HCMS for the Base Case and CO_2 EOR, respectively. The total CO_2 injected is lower than in the WFA simulation and injection over 50% HCPV may be optimum.

The production forecast is based on fractional flow curves derived from the area models. Table 5.2.4.2 shows the %HCPV of CO_2 and water, injected and WAG ratio. The CO_2 injected, produced and stored is shown on Table 5.2.4.3. The CO_2 injection is that required for the simulation prediction. To maximize CO_2 storage all produced CO_2 should be reinjected which would also increase oil recovery. Waterflood oil in the EOR case is accelerated compared to the base case waterflood production.

Figure 5.2.4.2 shows the complete new gathering system (black) that goes to all wells and new CO_2 and water injection lines (red) to all new injection wells. The existing solvent and water injection lines to existing injection wells were assumed to be adequate for CO_2 EOR. New CO_2 and water injection lines were run from the nearest existing solvent injection well to new injection wells. A complete new gathering system was installed because of potential higher operating pressure, corrosion in the existing system and desire to produce low CO_2 concentration wells to gas plant rather than dilute produced CO_2.

It was assumed that the existing treating plant and waterflood plant would be used for the EOR project. It is also assumed that CO_2 and solution gas separation will be required.

Table 5.2.4.3 summarizes some of the key parameters results for both the Base Case Waterflood and the CO_2 EOR generated from the study. CO_2 EOR incremental oil recovery is over 4.5 e^6m^3 or 3.0% OOIP is forecast by the simulation with the injection of over 45 million tonnes of CO_2, 40% HCPV of CO_2 at a

WAG of 1:1 followed by chase water in four of the five areas. Source CO_2 is required for 22 years, 9 years at maximum rate of 2,000 tonne per day. CO_2 injection shown is that required to meet the forecast; if all produced CO_2 were injected 10.4 million tonnes would be stored. Net CO_2 utilization is acceptable at 2.28 tonne/m^3 (7 mcf/Bbl); Gross CO_2 utilization is a poor 9.96 tonne/m^3 (30.2 mcf/Bbl), based on EOR oil.

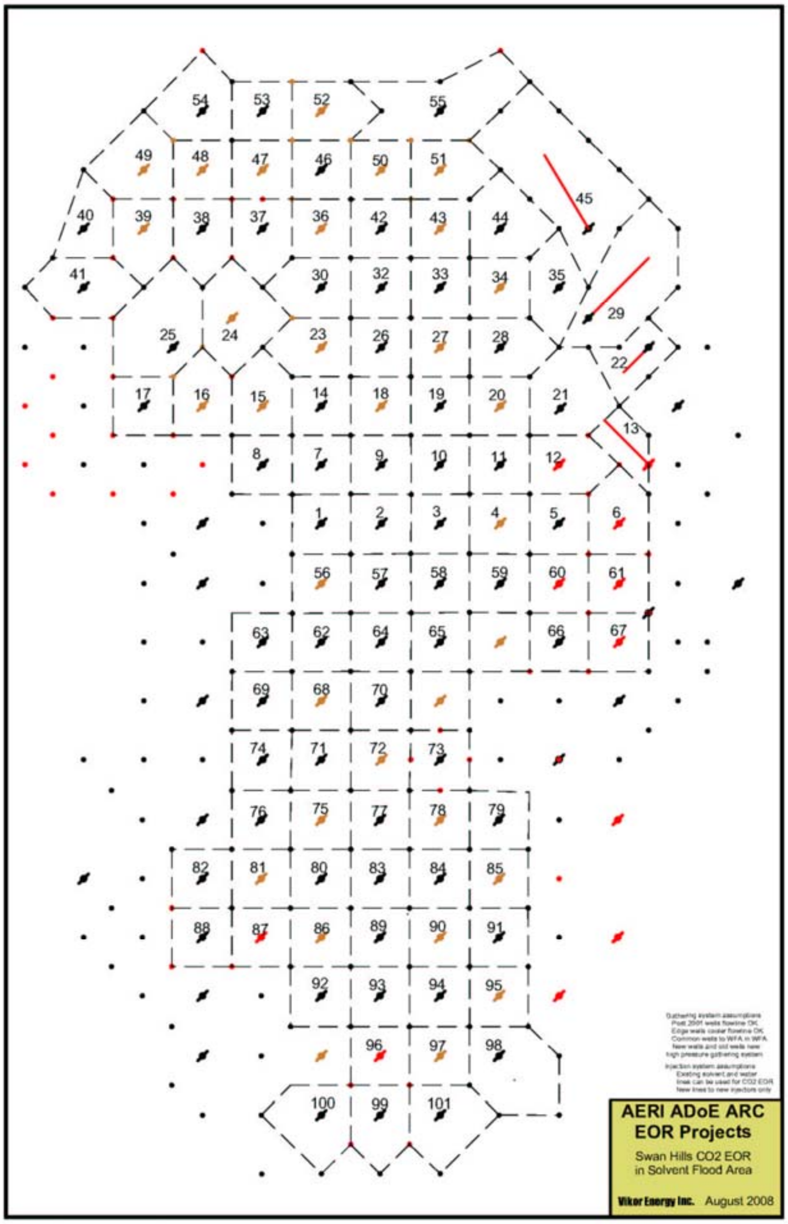


Figure 5.2.4.1: Wells used in Swan Hills BHL SFA development plan (existing wells in black, wells drilled since 2001 in red, new wells for development plan in gold); wells outside the patterns are in the WFA

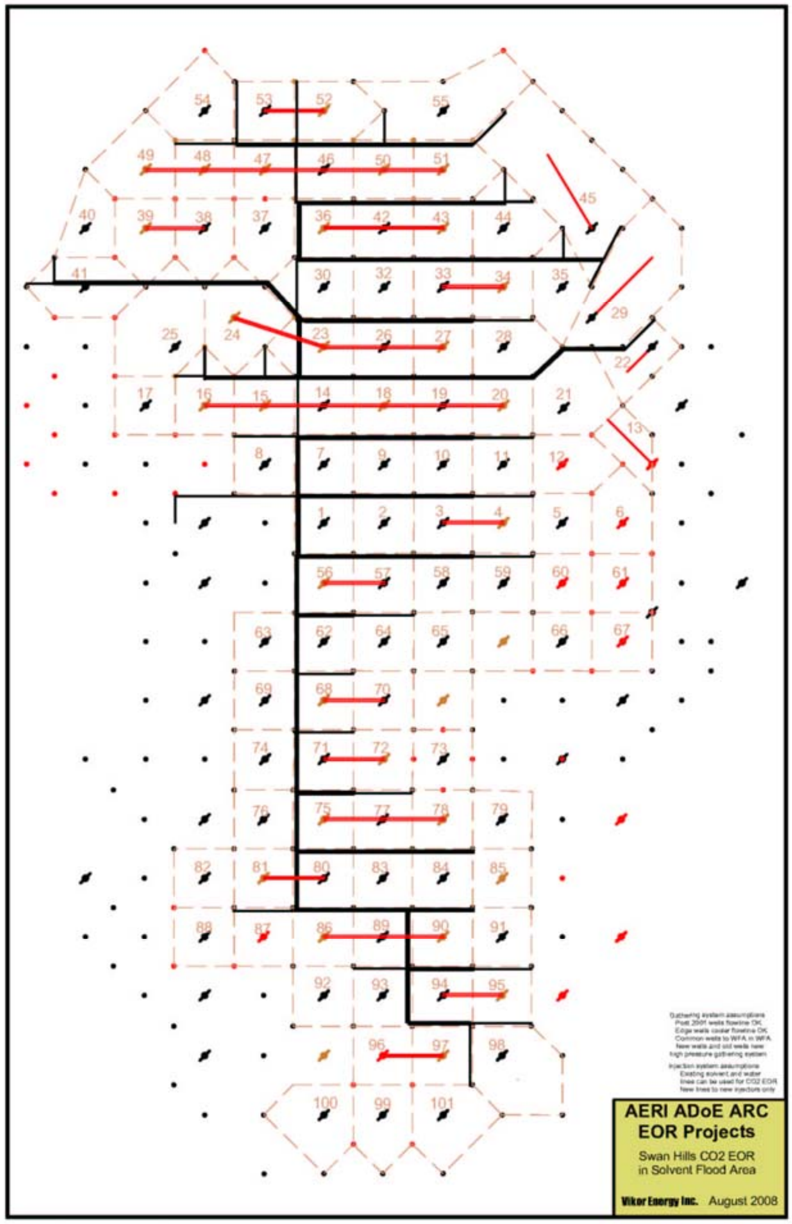


Figure 5.2.4.2: Plan for gathering system lines (black) and CO_2/water injection lines (red)

Table 5.2.4.3 BHL CO_2 EOR SFA
Summary of Results

OOIP	149.4	e^6m^3	939.8	10^6 Bbl			
Oil Production							
Base Case	1,316	e^3m^3	8,275	10^3 Bbl	0.9%		estimate
CO_2 EOR	4,539	e^3m^3	28,547	10^3 Bbl	3.0%		"T" Factor
Total	5,854	e^3m^3	36,822	10^3 Bbl	3.9%		0.78
	Production				Sales		
Base Case	84	e^6m^3	3.0	bcf	84	e^6m^3	
CO_2 EOR	1,231	e^6m^3	43.7	bcf	739	e^6m^3	
Total HCMS	1,315	e^6m^3	46.7	bcf	822	e^6m^3	
Solution Gas	585	e^6m^3	14.3	bcf	404	e^6m^3	
CO_2 Injection	45,211	Gg	24,292	e^6m^3	862.2	bcf	40.5%
CO_2 Purchased	10,337	Gg	5,554	e^6m^3	197.1	bcf	9.3%
CO_2 Production	38,959	Gg	20,933	e^6m^3	743.0	bcf	34.9%
WAG Ratio	1:1		Maximum Source CO_2		9	years	
Maximum purchased CO_2			2,000	tonne/day	38,142	mcf/d	
Maximum injected CO_2			8,200	tonne/day	156,373	mcf/d	
CO_2 Utilization Factor		(CO_2 EOR oil only)					
Gross	9.96	t/m^3	30.20	mcf/Bbl			
Net	2.28	t/m^3	6.91	mcf/Bbl			
Water Injection					% HCPV		
Chase & WF	250,188	e^3m^3	1,573,638	10^3 Bbl	117.9%		
WAG	95,128	e^3m^3	598,340	10^3 Bbl	44.8%		

Risk Factors

The most significant technical risks include:

1. Prior miscible solvent flood operations have produced a significant portion of the miscible oil in the reef making oil saturation when the CO_2 EOR is initiated difficult to predict. This is a quaternary flood rather than tertiary, the first in the world.
2. Simulation predictions are very complex and many simplifying assumptions must be made. The difficulties completing the runs and inability to meet expected WOR and the much lower total oil recovery in the simulator compared to the field is of concern. Performance of all of the areas was not history matched, consequently prediction is less reliable.
3. The operation would need to be integrated with the lower quality waterflood area that borders much of the solvent flood area.

5.2.5 Redwater D-3

The information provided in this section of the report assumes a horizontal flood commercial CO_2 development strategy utilizing inverted 9-spot patterns. ARC Resources agrees that the results of the report are representative of the development strategy employed, but have chosen to evaluate the performance of a vertical flood development strategy. While ARC Resources is in the early stages of their evaluation, the work completed to date suggests a vertical flood development strategy should perform better than a horizontal flood development strategy.

The Redwater D-3 pool is one of the largest conventional oil fields in Canada. The area covered 15,100 ha and contained 229.55 e^6m^3 (1,444 million barrels) of OOIP, production to date equals 132.6 e^6m^3 (834 million barrels), 57.8% OOIP, see Table 5.2.5.1. The OOIP utilized is slightly higher than carried by the ERCB. The production forecast for both Base Case waterflood and CO_2 EOR based on compositional modelling using the GEM simulator. The forecasts were utilized as developed **without** any risk factors; the recoveries appear to be reasonable.

Table 5.2.5.1 Redwater D-3 CO_2 EOR

Development Plan Parameters							**Area Performance**				
Area	Injectivity per well	Productivity per well	OOIP	Predict WOR	Recovery to date		% HCPV Inject			Recovery % OOIP	
	(Rm^3/d)	(m^3/d)	e^3m^3	2013	e^3m^3	OOIP	CO_2	Total	WF	Base	EOR
A 1	5,000	400	72,231	200	28,043	38.8%	101%	400%	202%	0.9%	4.2%
A 2	2,500	500	85,453	300	58,029	67.9%	99%	314%	0%	0.0%	4.5%
A 3	3,000	200	71,865	150	46,567	64.8%	101%	504%	288%	1.6%	4.6%
Total			229,548		132,639	57.8%					
total millions barrels			1,443.8		834.3						

The EOR project was developed with 222 inverted 9 spot patterns using existing vertical wells on 16 ha (40 acre) per well spacing. The forecast assumes all wells stay on production for the life of the patterns that they service at rates provided from analysis of historical well performance in each area. Analysis indicates that the displacement process is horizontal, not vertical as assumed in previous EOR predictions in the pool. ARC Resources believes the displacement process is vertical, which is preferable if vertical continuity is sufficient for the process to work. Recovery from the pool is excellent to date, in part because of very efficient fluid handling. CO_2 EOR will have to be operated very efficiently to be economic as large volumes of fluid must be processed. Incremental recovery is relatively low because the process is not fully miscible and the remaining target is low.

Figure 5.2.5.1 shows the development area used and the layout of the 48 pattern clusters. Historical injectivity and productivity are excellent and shown in Table 5.2.5.1 for each area. Note that most pattern clusters are composed of several inverted 9 spot patterns to facilitate development planning. The project utilizes 222 existing vertical production wells converted to injection wells and 691 existing production wells as shown on Figure 5.2.5.2.

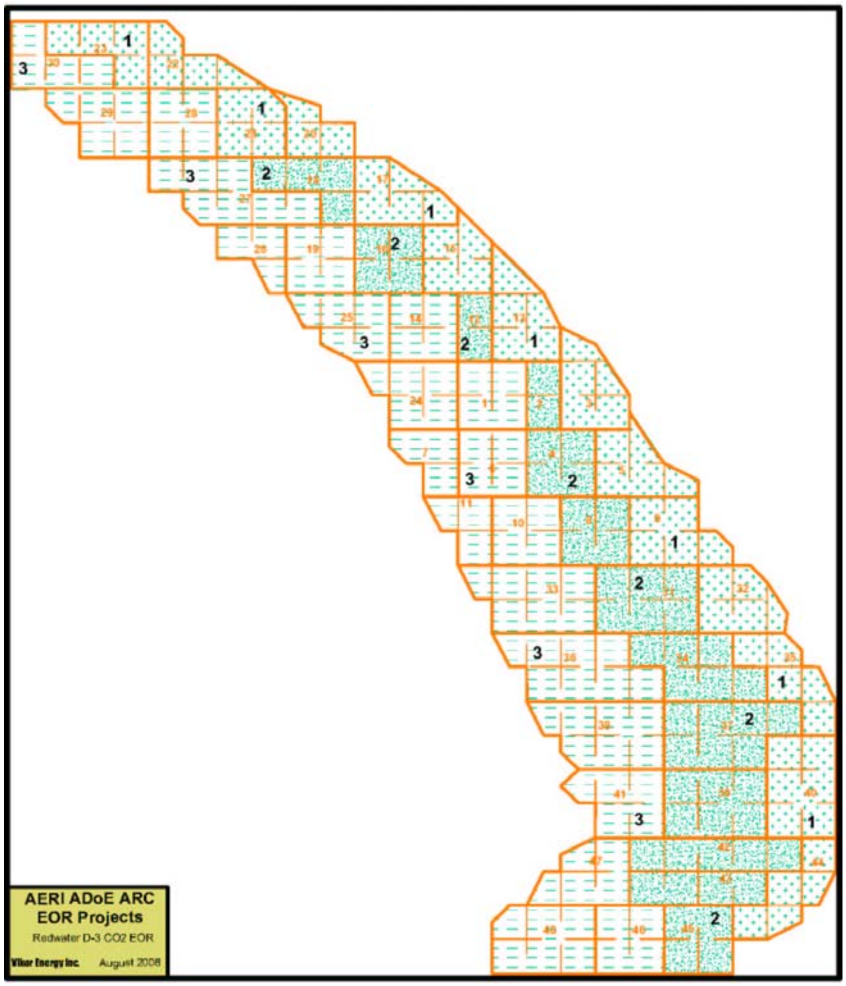


Figure 5.2.5.1: Development plan areas and layout of the 48 pattern clusters. Facies are indicated by 1: Forereef, 2: Reef buildup and 3: Lagoonal

The Redwater D-3 pool was originally developed on 40 acre per well spacing. Some of the wells have had the D-3 zone abandoned and have been recompleted up hole so they may not be available for the CO_2 EOR Project. Because of the excellent injectivity and productivity fewer wells can be utilized with an acceptable extension in project life. This will result in a reduction in capital cost to recomplete fewer wells that may be offset by higher costs to drill some new wells. Well operating costs will be reduced with fewer wells.

The predicted oil recovery under Base Case waterflood and the oil recovery above Base Case from CO_2 EOR are shown in Table 5.2.5.1. The development plan shut-in wells in the area at a WOR of 300, higher than other prototype pools, because of demonstrated efficient fluid handling. It is expected that Area 2 will have reached a WOR of 300 by start of EOR, therefore no additional waterflood recovery is predicted from this area.

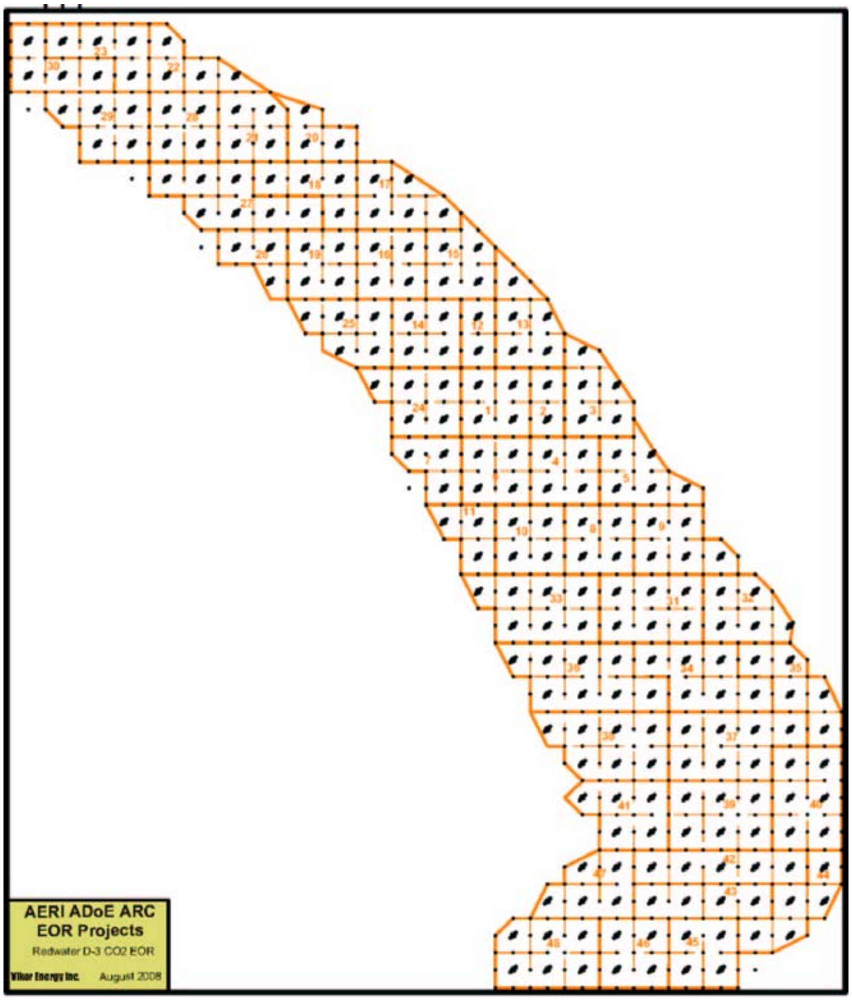


Figure 5.2.5.2: Layout of Patterns used for Development Plan

The full area production forecast is generated using fractional flow curves derived from the modeling of the 3 areas in the development area for continued waterflood using current strategy to a WOR of 300 and CO_2 EOR at a WAG of 1:1. Table 5.2.5.1 shows the total %HCPV of CO_2 and water, injected during WAG injection followed by chase water. The forecast for all the areas used a total injection up to 500% HCPV.

The CO_2 injected, produced and stored are shown on Table 5.2.5.2. The CO_2 injection forecast is that required to meet simulation prediction. In order to maximize CO_2 storage all produced CO_2 should be reinjected. This would also increase oil recovery.

Figure 5.2.5.3 shows the main new gathering system (in blue) and CO_2 and water injection lines (in red). In addition to the lines shown, an 800 m line to all wells was also included. As the injection wells are converted from existing producers, a complete new water injection system was installed. A complete new gathering system was installed to operate at high pressure, potential corrosion in existing system and desire to produce low CO_2 concentration wells to gas plant rather than dilute produced CO_2.

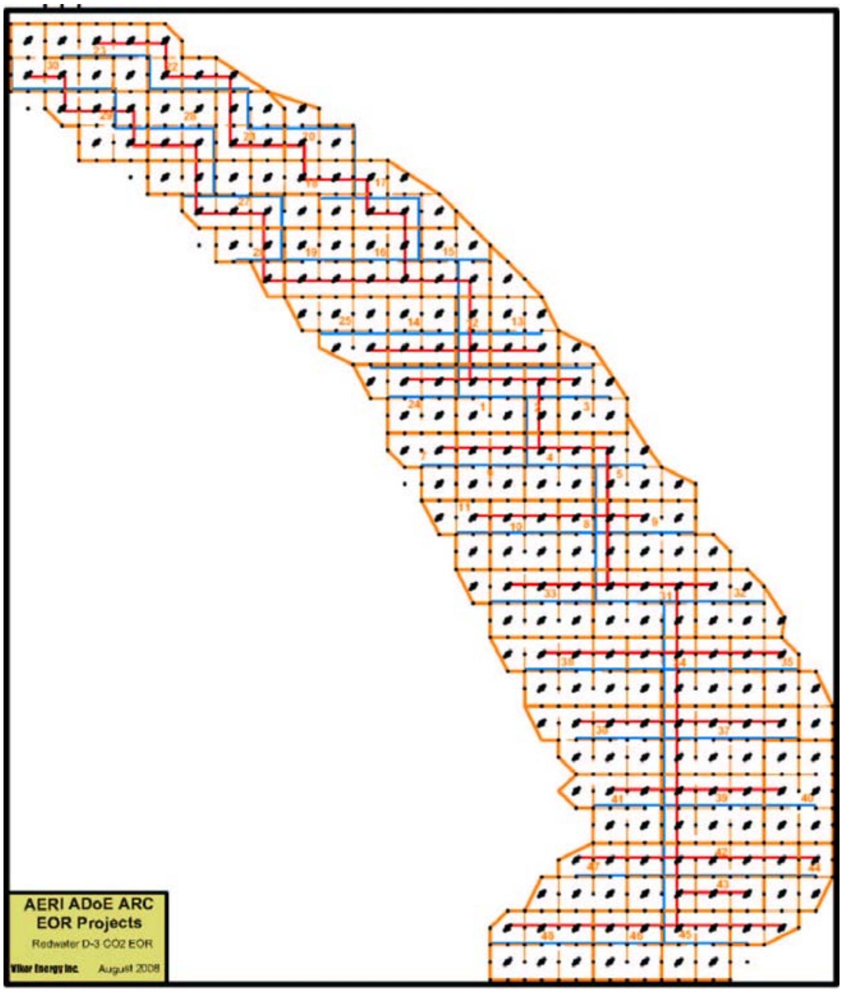


Figure 5.2.5.3: Pipeline layout showing new gathering system (blue) and water lines (red)

Table 5.2.5.2 summarizes some of the key results for both the Base Case Waterflood and the CO_2 EOR generated from the study. CO_2 EOR incremental oil recovery is 12.8 e^6m^3 or 5.6% OOIP is forecast by the simulation. The discrepancy between the recovery shown on Table 1 and the prediction is because waterflood recovery terminates at WOR of 300 but under EOR the oil is produced because WOR is lower. Sixty two million tonnes of CO_2, equivalent to 100.1% HCPV of CO_2, were injected at a WAG of 1.1 followed by up to 275% HCPV of chase water. Because of the high processing rate and tight well spacing the injection could be completed in about 30 years. Source CO_2 is required for 14 years, 11 years at maximum rate of 4,000 tonne per day. CO_2 storage is 11.1 million tonnes, only one sixth of the injected CO_2. CO_2 injection shown is that required to meet the forecast. If all produced CO_2 were injected, then 17.5 million tonnes would be stored. Net CO_2 utilization is good at 1.37 tonne/m^3 (4.1 mcf/Bbl); gross CO_2 utilization is 4.85 tonne/m^3 (14.7 mcf/Bbl), based on EOR oil.

Redwater is strategically located very close to major sources of higher purity CO_2. It also has potential for storage in the large aquifer under the oil pool.

Table 5.2.5.2 Redwater D-3 CO_2 EOR

Summary of Results

OOIP	226.7	e^3m^3	1,426	10^6 Bbl				
Oil Production								
Base Case	1,781	e^3m^3	11,204	10^3 Bbl	0.8%		estimate	
CO_2 EOR	12,778	e^3m^3	80,369	10^3 Bbl	5.6%		"T" Factor	
Total	14,559	e^3m^3	91,573	10^3 Bbl	6.4%		0.88	
Natural Gas Sales			0	e^6m^3	0.0	bcf		
CO_2 Injection	62,022	Gg	33,325	e^6m^3	1,182.8	bcf		100.1%
CO_2 Purchased	17,482	Gg	9,393	e^6m^3	333.4	bcf		28.2%
CO_2 Production	50,935	Gg	27,367	e^6m^3	971.4	bcf		82.2%
WAG Ratio	1:1		Maximum Source CO_2		11	years		
Maximum purchased CO_2			4,000	Mg/d	76.3	mmcf/d		
Maximum injected CO_2			15,699	Mg/d	299.4	mmcf/d		
CO_2 Utilization Factor		(CO_2 EOR oil only)						
Gross	4.85	t/m^3	14.72	mcf/Bbl				
Net	1.37	t/m^3	4.15	mcf/Bbl				
Water Injection					% HCPV			
Chase & WF	682.2	e^6m^3	4,291	10^6 Bbl	275.4%			
WAG	280	e^6m^3	1,758	10^6 Bbl	112.8%			

Risk Factors

The most significant technical risks include:

1. The flood must be operated at near miscible conditions to achieve predicted recovery. Reaching this pressure may be difficult with the underlying aquifer that is connected with the massive Cooking Lake aquifer.
2. The operating pressure and temperature are very close to CO_2 critical point complicating the performance prediction.
3. Whether the CO_2 flood can be operated as a vertical or horizontal displacement process is uncertain. The geological analysis used in this study suggests that barriers could preclude a vertical displacement process. The operator does not believe these barriers are continuous and is piloting to see if vertical displacement can be achieved. The horizontal displacement process evaluated in this study should be more conservative than a vertical displacement process.
4. Gravity override will very negatively impact a horizontal displacement process in the thick zones as the CO_2 is much lighter than oil (250 kg/m^3) at operating conditions.
5. If reservoir pressure could be increased to hydrostatic level, CO_2 density could be increased to about 700 kg/m^3 reducing gravity override and increasing CO_2 storage, but utilization factor would be much poorer.
6. The pool has many old wells, is relatively shallow and is proximate to areas with significant population and hence safety precautions will be critical.

A field pilot test will be necessary to confirm that the CO_2 will mobilize sufficient residual oil at achievable operating conditions.

5.3 EXTRAPOLATION TO ANALOGUES

The results of sector model simulation and prototype development plans were used to extrapolate results to analogue pools. For each of the major categories studied in the numerical modeling task, a number of analogue pools were selected for extrapolation of results. The broad characteristics of the pool types are given in Table 5.3.1.

Table 5.3.1: Data for selected pool types (ERCB 2006 Reserves)

Pool Types	OOIP 10^6 m^3	Total RF (range)	Major Pools
BHL Solvent Flooded - 8 pools	503.1*	0.39 to 0.50	Swan Hills, Swan Hills South, Judy Creek A
BHL-water flooded -10 pools	347.6*	0.27 to 0.55	Swan Hills, Judy Creek A, Carson Creek North and Virginia Hills
D-2 - 6 pools	154.3	0.25 to 0.65	Fenn-Big Valley, Leduc Woodbend. Joffre
D-3 – 5 pools	447.6	0.35 to 0.67	Redwater, Bonnie Glen, Sturgeon Lake South
Cardium - 5 pools	1070.8	0.2 to 0.50	Pembina, Ferrier
Total	**2523.4**		

*includes platform and reef build-up

Methodology

The methodology adopted to predict performance of analogue pools is based on the following assumptions/observations:

a. Within a given analogue grouping, there will be variations between various targets and patterns, reflecting reservoir quality (injectivity/productivity or rate of processing) and floodability (continuity of more prolific intervals impacting on volumetric sweep efficiency, and nature of 'thief' zones leading to recycling of water/CO_2)

b. Because the above factors also will have been operative during the preceding water flood or HCMF, data on waterflood and HCMF performance implicitly contain clues to subsequent performance under CO_2 EOR.

c. The incremental oil recovery due to CO_2 flooding at an analogue can be 'scaled' based upon prior performance of the analogue under waterflood and the ratio between waterflood incremental oil recovery and EOR incremental recovery at the prototype. This ratio can be obtained from field results, simulation or evaluations by credible sources such as ERCB.

d. In the case of quaternary flooding (CO_2 flooding after HCMF), a similar approach was used. In that case, incremental reserves due to quaternary flooding at the analogue were estimated based on tertiary (HCMF) recoveries.

e. Incremental oil recovery factors for tertiary HCMF for a very large solvent slug (say, 100% HCPV solvent slug followed by terminal waterflood) will be the same as recovery factor due to a combination of partial tertiary flood (say 15% HCPV solvent slug) followed by 100% HCPV CO_2 injection in the WAG mode, followed by a terminal water flood. This assumption was necessary for this exercise because of availability of limited amount of field/simulation results.

f. CO_2 injection occurs simultaneously (or phased in the same manner as done at the prototype) at the entire analogue area.

g. When certain pieces of specific reservoir data were missing, it was assumed that ERCB reserves data are valid for the prototype as well as various specific analogues.

Forecasting Steps

1. Verify if the areas indicated as analogous from geology are also analogous from performance point of view. This involves extracting and comparing historical production data from the ERCB data base of both the analogue pools and the prototype areas used in preparing the development plan for the prototype.

2. Verify if the data from prototypes can be readily extrapolated to analogs. (Are there different dominating mechanisms or influences from adjoining regions?)

3. Determine/estimate various incremental recovery factors based on assumptions c. to e. This involves plotting calendar day oil production rate and oil cut for each analogue and prototype area versus the respective cumulative oil production and extrapolating the curves to an economic limit (oil cut 1%, oil rate 1 m^3/d). Ideally these curves should converge to the same point on the cumulative oil axis.

4. Perform analyses in a non-dimensional basis (Δ RF (%OOIP); slug size expressed in HCPV). Injection/production rates can be ‘scaled’ based on ratios of historic processing rates during waterflooding in the prototype and analogue.

5.3.1 Beaverhill Lake Pools

Prototype Pool/Areas Selected

The prototype for waterflooded BHL pools was based on the Judy Creek BHL A pool sector model and the BHL A&B pool waterflooded Area Models to which results of the Judy Creek sector model were extrapolated. The BHL waterflood areas were designated:

WFA1 located along the western reef rim. This is an area that has had relatively little injection/production. Data based on only 5 operating wells may not be representative when the area is infilled to complete various proposed patterns. WF performance here was not very promising and correspondingly, EOR here may need to be closely scrutinized.

WFA2 located along the western reef rim to the north of WFA1. The area is of intermediate reservoir quality and has produced from 22 wells.

WFA3 located along the south-western reef rim to the south of WFA1, this area is of intermediate reservoir quality with production from 13 wells.

WFA4 along the eastern reef rim. This area is of relatively high reservoir quality that has had good oil production from 45 producers.

Table 5.3.1.1 provides a summary of the performance of the waterflood areas and derives the parameter "Ratio of ΔCO_2 oil to ΔWF Oil" which is utilized later in estimating incremental oil from the waterflood regions of BHL analogues. The very high recovery factor for WFA4 is thought to be due to migration of oil to this area from adjoining parts of the field.

Table 5.3.1.1: Ratio Between Estimated Incremental CO_2 EOR Recovery to Waterflood Recovery for BHL Waterflooded Areas

Study Area	OOIP ($10^6 m^3$)	Indicated Δ RF [WF] oil by decline curve (Field data) (%OOIP)	Indicated Δ RF [WF] oil from simulation From Table 4.3.6.4 (%OOIP)	Δ RF due to CO_2 (by simulation) (%OOIP)	Ratio of Δ CO_2 flood/ Δ WF (by simulation)
WFA-2	12.999	15	42.8	20.7	0.484
WFA-3	7.341	7.5	41.0	20.8	0.507
WFA-4	13.866	80.3	40.1	29.1	0.726

In terms of effectiveness of waterflood in enhancing reserves, the most successful operations were in the WFA4, followed by WFA2, WFA3 and WFA1. Due to complications caused by fluid influx/efflux from Swan Hills WFA areas, indicated RFs for waterflood from areal model simulation were used in the following analysis to extrapolate performance to the analogue pools.

The prototype for solvent flooded BHL pools was the reefal area of the Swan Hills BHL A&B pool (the platform region was excluded). Five solvent flooded areas were chosen extrapolating performance to the full Swan Hills pool (Figure 5.2.4.1). These were:

SFA-1 in the West-Central part of the Swan Hills pool. This region is characterized by relatively high oil and gas production.

SFA-2 located to the NE of SFA-1 region. This is in the interior of the reef dominated by shoal/lagoonal facies with relatively poor oil rates and recoveries.

SFA-3 located further to the East and North of SFA-2 region. It is of relatively higher reservoir quality than SFA-1 and SFA-2 regions and has received relatively more solvent injection.

SFA-6 located to the South of SFA-1 region. The wells here have contributed relatively large volumes of oil.

SFA-7 region located to the South and East of SFA-6 region. This region has received a relatively large amount of solvent and contributed a large amount of oil.

Wells in each of the above regions were selected to include existing flooding patterns. Adjoining regions thus share common producers.

Rationale for Selecting Prototype Areas

The selection of the prototype areas was made on the basis of geology and production history. Each of the Beaverhill Lake pools consists of several pay intervals, separated by thick dense intervals. These pay intervals coalesce in the fore-reef region. The back-reef/interior regions are dominated by shoal/lagoonal facies. The five solvent flooded regions have different combinations of shoal/lagoonal facies within the fore-reef/ back reef.

Analogous Pools/ Areas

The main CO_2-EOR targets in the category of non-solvent flooded (or water flooded) Beaverhill Lake reservoirs include Carson Creek North (A & B), Snipe Lake and Simonette A and B, besides the non-solvent flooded portions of larger pools such as Swan Hills. Carson Creek North is a limestone reef whereas Snipe Lake is a dolomite reef. Both these have been subjected to line drive water flood with relatively strong waterflood performance. Carson Creek North is the largest of these targets and has also performed much better in terms of recovery factors for primary and water flooding mechanisms.

Solvent flooded Beaverhill Lake pools analogous to the Swan Hills prototype include Ante Creek, Goose River*, Judy Creek A, Judy Creek B, Kaybob*, Swan Hills South, Virginia Hills. The two pools marked by asterisk (*) are dolomite pools; the rest are mainly comprised of limestone. Tables 5.3.1.2 and 5.3.1.3 summarize the performance to date of the BHL pools considered in this study. As an historical aside, in initial exploitation, only Imperial Oil injected water across the full face in their Swan Hills waterflood. Mobil (Carson Creek N), Amoco (Swan Hills) and Shell (Virginia Hills) only followed this practice later. Initially they injected water at the bottom of the formation. In these pools, waterflood recovery is understated and HCM recovery is overstated.

The Beaverhill Lake analogue pools were examined in a geological context to determine which of the prototype area models they most resembled. Table 5.3.1.4 shows the assigned areal simulation upon which the analogue projections were based.

Various wells in the prototype and analogous BHL pools have performed strongly during primary, water flooding and solvent flooding periods, spanning about 50 years. Oil rate decline has been very gradual during the above three phases of exploitation. Whereas water injection helped in enhancing overall oil production, the response to solvent flooding has largely been subtle whereby the decline in oil rate was significantly arrested, leading to more than 45% oil recovery to-date and oil rates that are still very strong (although an order of magnitude lower than the peak oil rates).

Table 5.3.1.2: Performance of Some Water Flooded BHL Oil Pools (ERCB Reserves data 2006)			
Pool	OOIP (10^3 m^3)	Primary Recovery Factor	Inc. Water Flood Recovery Factor
Carson Creek North A & B	57,130	0.16	0.352
Snipe Lake	36,650	0.12	0.18
Simonette A Simonette B	7,764 3,145	0.25 0.15	0.30 0.25

Table 5.3.1.3: Performance of Some Solvent Flooded BHL Oil Pools (ERCB Reserves data 2006)				
Pool	**OOIP (10^3 m^3)**	**Primary Recovery Factor**	**Incremental Water Flood Recovery Factor**	**Incremental HCM Solvent Flood Recovery Factor**
Swan Hills	458,100	0.17 0.14	→ 0.11	0.23
Swan Hills South	151,100	0.17 0.05	→ 0.07	0.23
Judy Creek A Judy Creek B	126,200 39,730	0.16 0.20	0.25 0.24	0.09 0.05
Virginia Hills	76,910	0.23 0.20	→ 0.124	0.22
Kaybob A	49,100	0.16 0.12	→ 0.24	0.305
Goose River A	25,500	0.16	0.23	0.07
Ante Creek	6,398	0.16	→	0.23

During quaternary CO_2-EOR (CO_2 flood following tertiary HCM solvent flood), part of production revenue will also be derived from enhanced and accelerated solvent recovery. Our preferred exploitation strategy will be to use the existing flooding patterns where possible. In regions with thicker pay (fore-reef) or in lagoonal areas with significant amount of bypassed oil, there may exist some opportunities of reducing well spacing by drilling infill vertical/ horizontal wells.

Since most BHL pools have somewhat similar geological characteristics and performance histories, empirical methods based on similarity principles should provide reasonable estimates of performance for various analogous pools. Results based on reservoir simulation for the sub-prototype regions (SFA-1, SFA-2, etc) will therefore be used to develop the desired empirical correlations. It should be noted that differences in the reservoir quality of individual pools or regions, past exploitation strategies and lithology (dolomite reservoirs at Kaybob and Goose River) may limit accuracy of extrapolations. An example of the application of the methodology is provided in the next section for the Judy Creek BHL A pool.

Table 5.3.1.4: Analogues to Beaverhill Lake Waterflood Prototype Areas and Beaverhill Lake Solvent Flood Prototype Areas

Field/Pool	Recovery Process	OOIP 10^3m3	Recovery Factor Primary	Recovery Factor IOR/EOR	Net Pay m	Porosity %	Reef Type	Lithology	Analogue
Ante Creek Beaverhill Lake	SF	5931	16	23	6.9	6.3	Swan Hills Complex Cycle 1 Bank Margin Pool	Limestone	SFA1
Carson Creek North Beaverhill Lake A & B	WF	56930	16	35.2	20.8	8	Cycle 2 Isolated Swan Hills Reef	Limestone	WFA4
Goose River Beaverhill Lake A	SF	16160	16	30	17.9	9.4	NE Margin of Large Cycle 2 Swan Hills Reef	Limestone	SFA3
Goose River Beaverhill Lake A	WF	9341	16	23	10.3	7.3	NE Margin of Large Cycle 2 Swan Hills Reef	Limestone	WFA3
Judy Creek Beaverhill Lake A	SF	77950	16	34	24.6	9	Cycle 2 Isolated Swan Hills Reef	Limestone	SFA3
Judy Creek Beaverhill Lake A	WF	48030	16	25	12.6	9	Cycle 2 Isolated Swan Hills Reef	Limestone	WFA2
Judy Creek Beaverhill Lake B	SF	28370	20	29	25.6	9.9	Sheltered Cycle 2 Swan Hills Reef	Limestone	SFA1
Judy Creek Beaverhill Lake B	WF	11360	20	24	10.4	8.5	Sheltered Cycle 2 Swan Hills Reef	Limestone	WFA2
Kaybob Beaverhill Lake A	SF	34000	16	30.5	17.8	7.6	Cycle 2 Isolated Swan Hills Reef	Limestone	SFA3
Kaybob Beaverhill Lake A	WF	10000	16	24	18.6	6.2	Cycle 2 Isolated Swan Hills Reef	Limestone	WF4
Simonette Beaverhill Lake A	WF	9162	25	30	15.7	8	Swan Hills Complex Bank Margin Pool	Dolomite	WFA4
Simonette Beaverhill Lake B	WF	3145	15	25	14.5	7	Swan Hills Complex Bank Margin Pool	Dolomite	WFA4
Snipe Lake Beaverhill Lake	WF	31000	12	23	10.5	6.8	NE Margin of Large Cycle 2 Swan Hills Reef	Limestone	Redwater
Swan Hills Beaverhill Lake A & B	WF	163700	17	33	36.3	8	Cycle 2 Isolated Swan Hills Reef	Limestone	Prototype
Swan Hills Beaverhill Lake A & B	SF	261300	14	11	10.2	7	Cycle 2 Isolated Swan Hills Reef	Limestone	Prototype
Swan Hills South Beaverhill Lake A & B	SF	124800	18	30.7	22.2	8.4	Cycle 2 Isolated Swan Hills Reef	Limestone	SFA1
Virginia Hills Beaverhill Lake	SF	35340	23	22	19.6	9	NE Margin of Large Cycle 2 Swan Hills Reef	Limestone	SFA1
Virginia Hills Beaverhill Lake	WF	38930	19.9	12.4	8.7	9	NE Margin of Large Cycle 2 Swan Hills Reef	Limestone	WFA4
Total OOIP		965449							

5.3.1.1 Judy Creek BHL A Pool

Solvent flooded areas of Judy Creek BHL A pool were examined in sections 22, 23, 24, 25, 26, 27, 34, 35 and 36 of Township 63 Range 11 W5M; Sections 28, 29, 30, 31, 32 & 33 of Township 63 Range 10 W5M; Sections 4, 5, 6, 7, 8 & 9 of Township 64 Range 10 W5M; and Sections 1, 2, 3, 1 & 11 of Township 64 Range 11 W5M.

The pool is operated by Pengrowth and has been extensively developed under HCMF using ethane as the HCM solvent. Many of the original HCMF patterns, now under chase waterflood, continue to produce injected HC solvent. New HCMF solvent flood patterns are added as produced ethane becomes available. As noted in Figures 5.3.1.1 to 5.3.1.4, the most prolific area of Judy Creek A (and the area with the most solvent injection) is in the north-east part of the pool. Areas to the south and west are much less productive. The number of waterflood patterns continues to decrease as more solvent flood patterns are added. Comparable plots of the performance of the Swan Hills waterflooded prototype area WFA2 and the Swan Hills solvent flooded prototype area SFA3 that are used as comparison for the methodology are provided in Figures 5.3.1.5 to 5.3.1.7 and Figures 5.3.1.8 to 5.3.1.11, respectively.

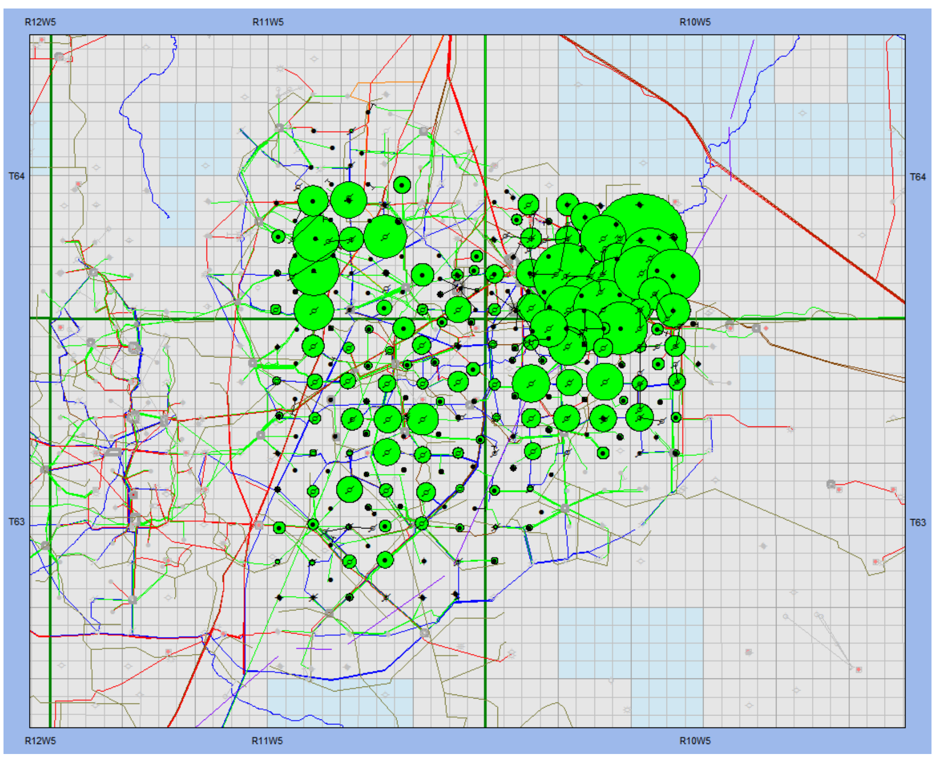


Figure 5.3.1.1: Distribution of Cumulative oil produced (Judy Creek A Solvent Flood area)

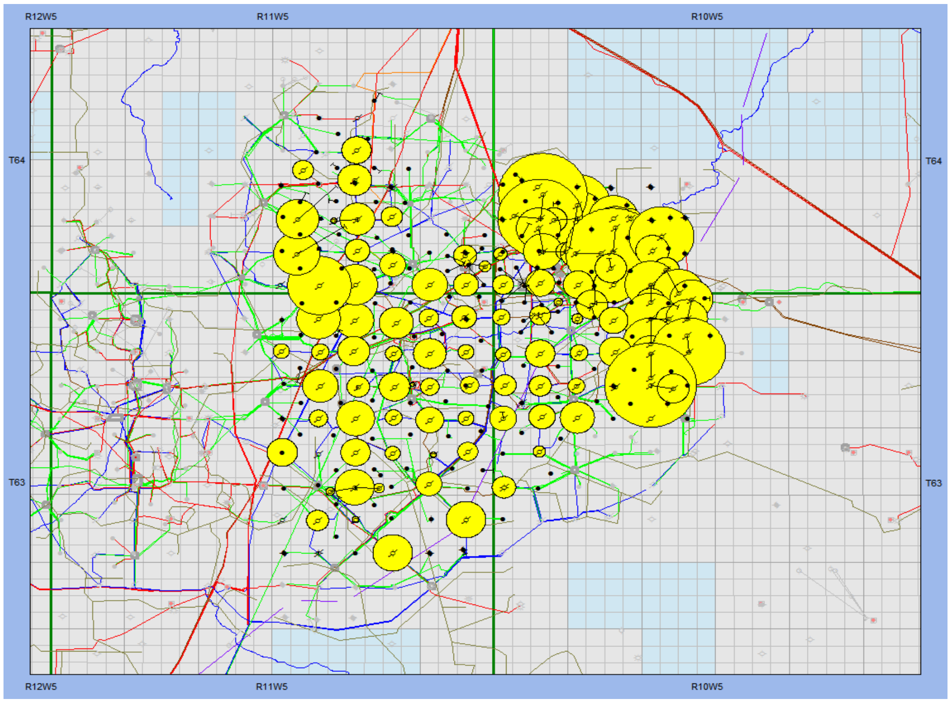


Figure 5.3.1.2: Distribution of Cumulative Solvent Injected (Judy Creek A Solvent Flood area)

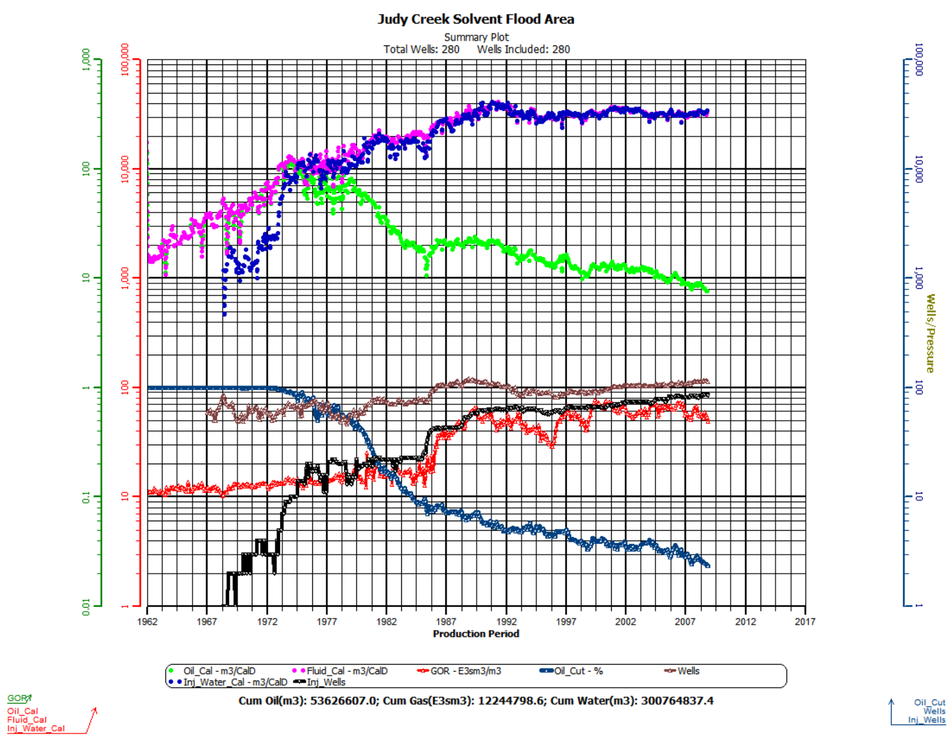


Figure 5.3.1.3: Oil rates and Oil-cuts as functions of time (Judy Creek BHL A Solvent Flood area)

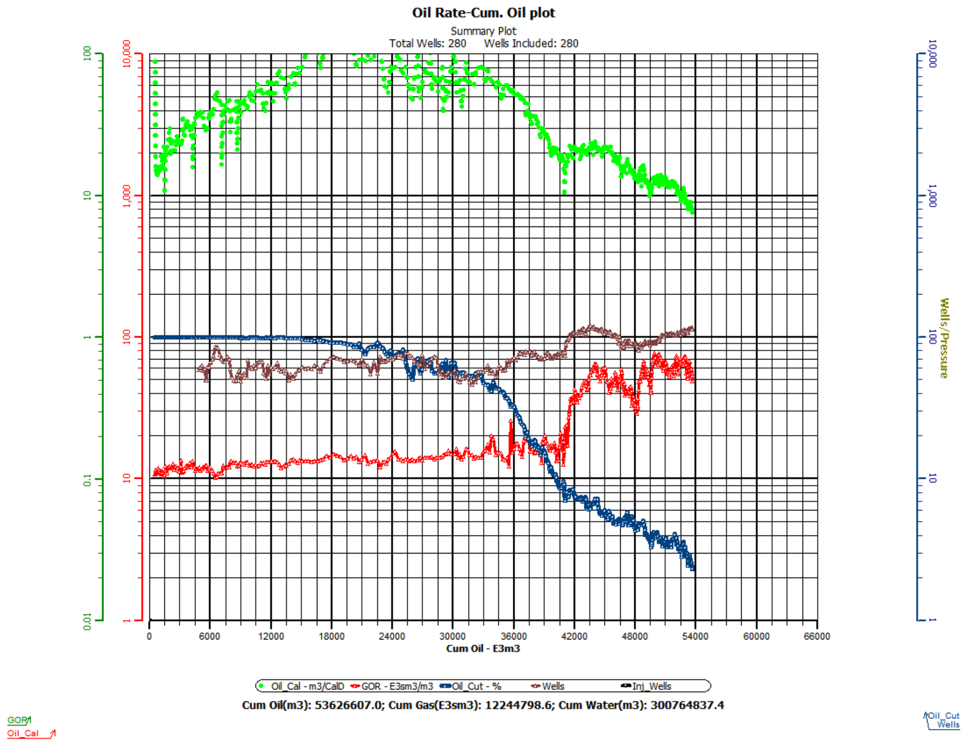


Figure 5.3.1.4: Oil rates and Oil-cuts as functions of Cumulative Oil produced (Judy Creek BHL A Solvent Flood area)

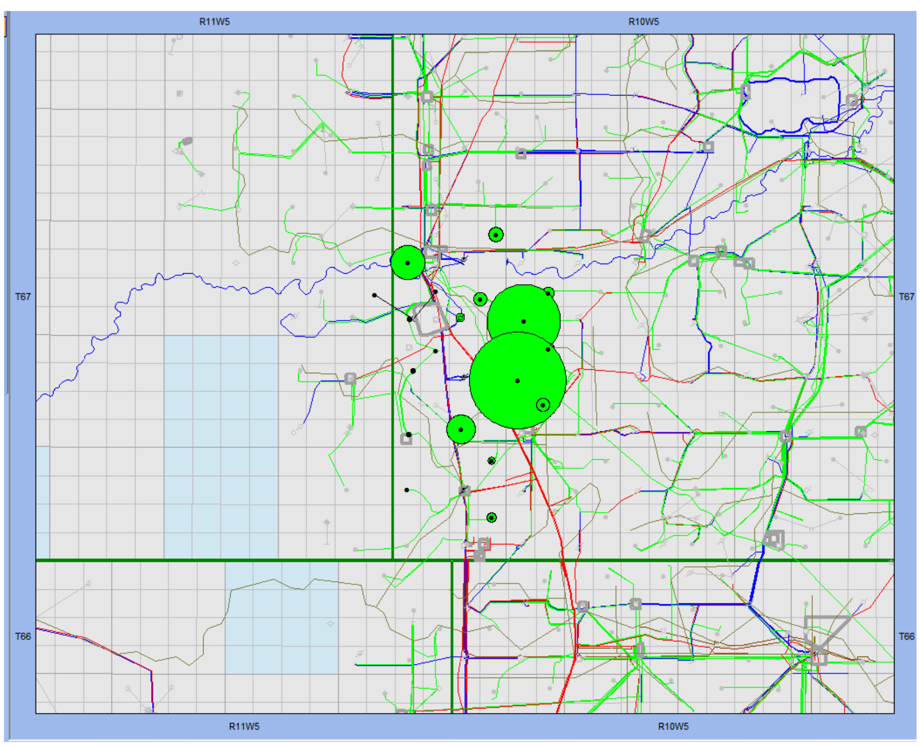


Figure 5.3.1.5: Distribution of Cumulative Oil Produced in the Swan Hills WFA2 area model

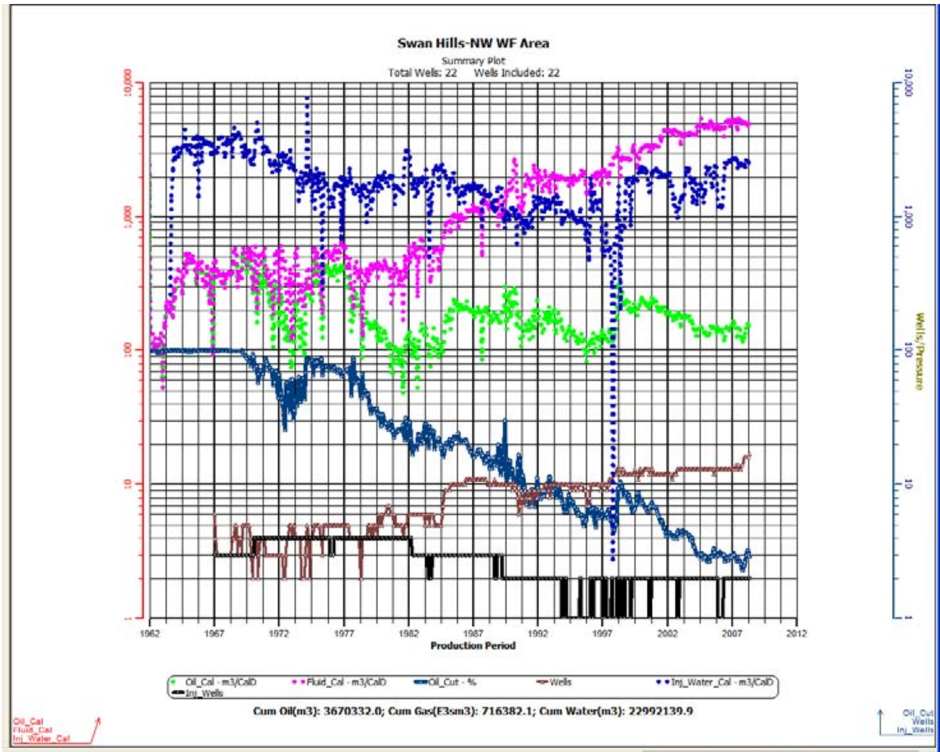


Figure 5.3.1.6: Oil rates and Oil-cuts as functions of time (Swan Hills WFA2)

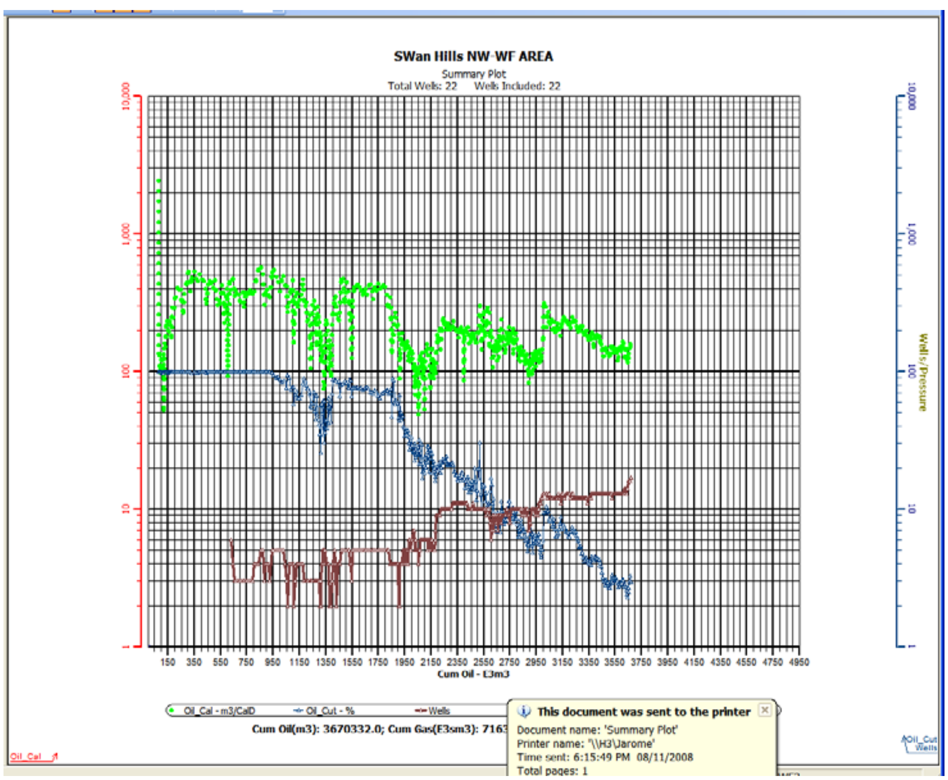


Figure 5.3.1.7: Oil rates and Oil-cuts as functions of cumulative oil produced (Swan Hills WFA2)

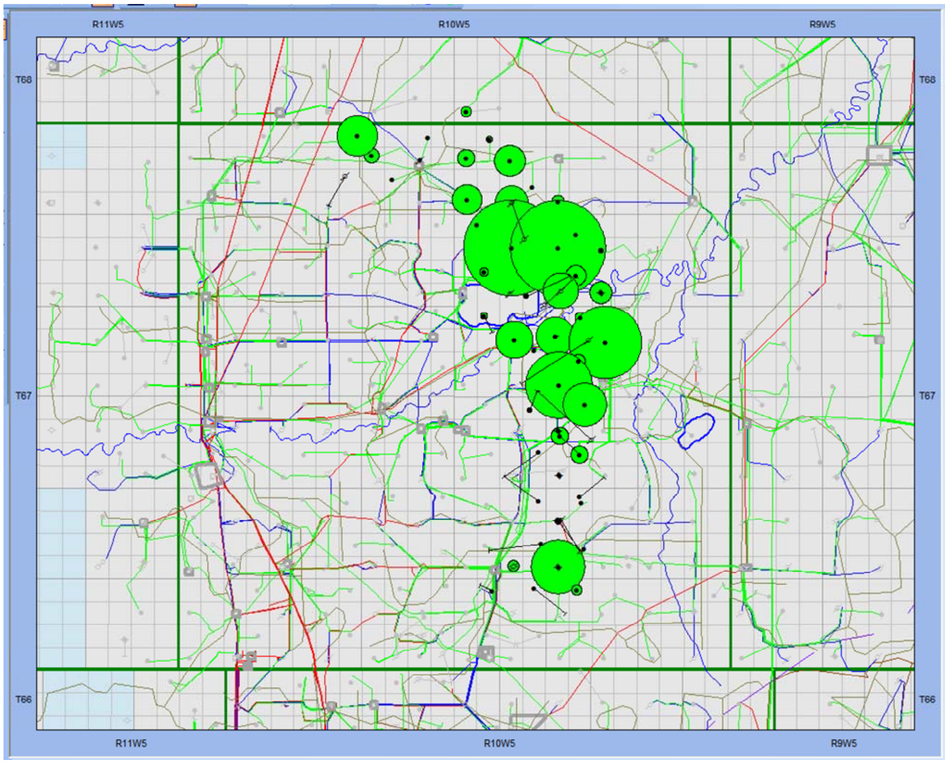


Figure 5.3.1.8: Distribution of Cumulative Oil Produced Solvent Flood Prototype Area SFA3

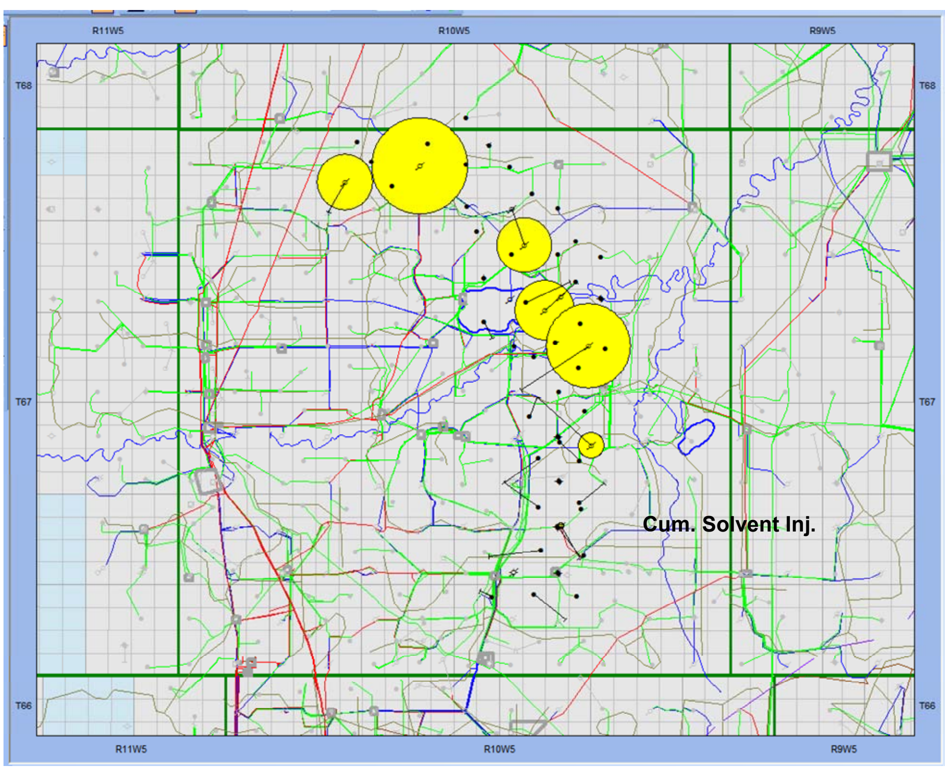


Figure 5.3.1.9: Distribution of Cumulative Solvent Injected Solvent Flood Prototype Area SFA3

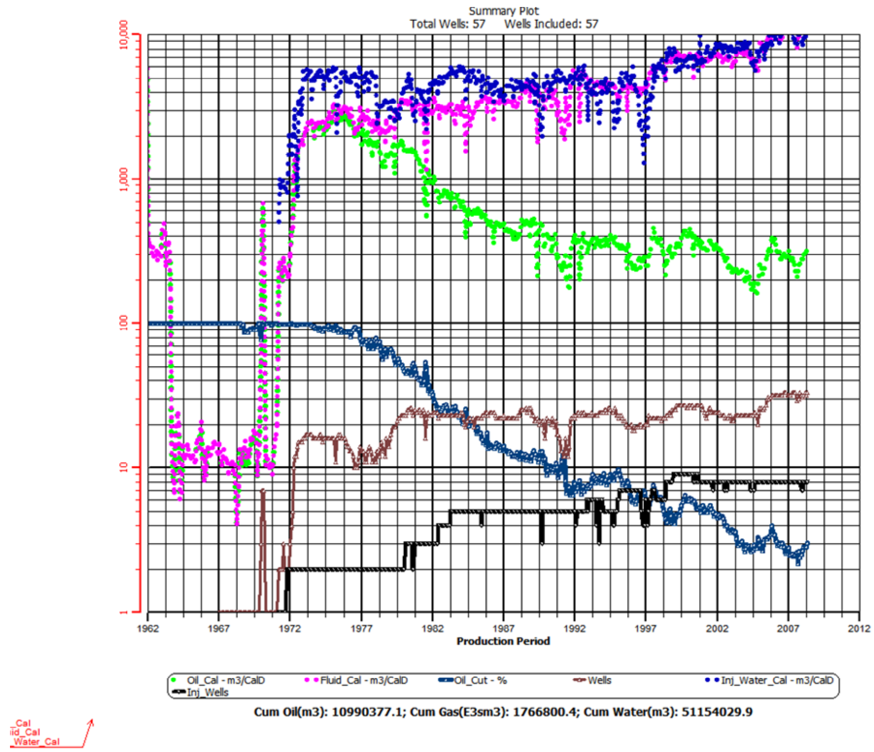


Figure 5.3.1.10: Oil rates and Oil-cuts as functions of time Solvent Flood Prototype Area SFA3

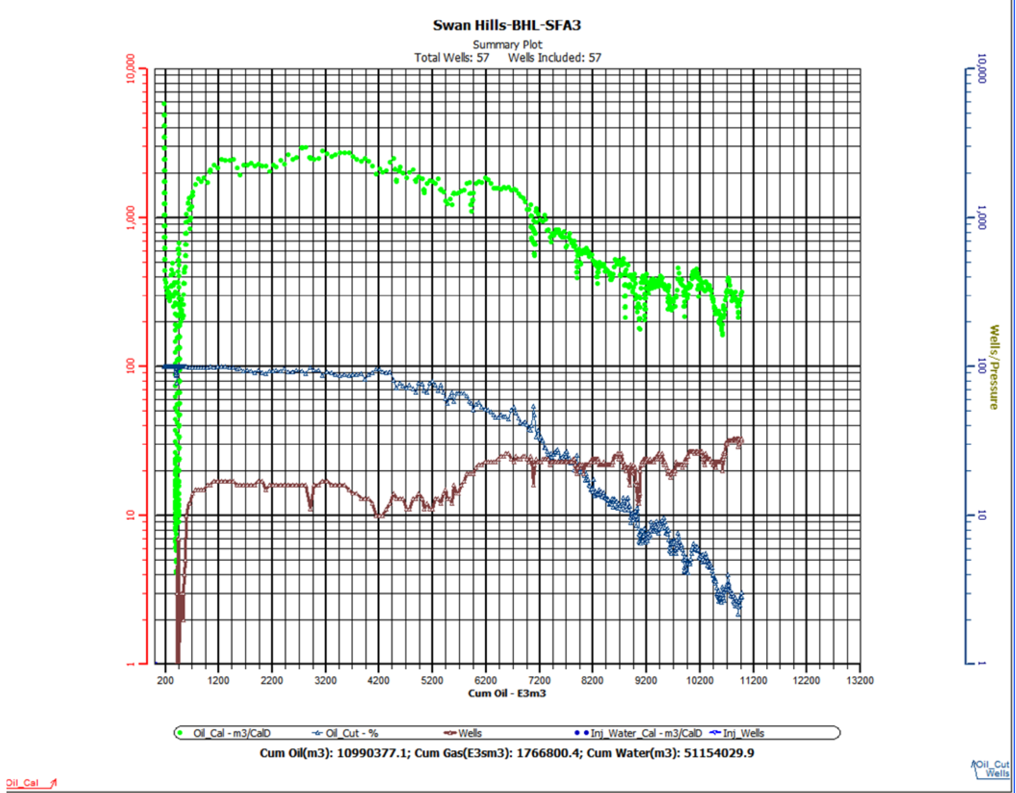


Figure 5.3.1.11: Oil rates and Oil-cuts as functions of Cumulative Oil produced Solvent Flood Prototype Area SFA3

Table 5.3.1.5 summarizes the analysis of the production plots and provides the estimated incremental oil based on the methodology.

Table 5.3.1.5: Estimated incremental CO_2 EOR for Judy Creek BHL A Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF oil decline curve or for WF from simulation 10^6m^3 (RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3
SFA-3	17.66	1.0 (5.7%)	2.7%	0.47	
Judy Creek HCMF Area	77.95	7.5 (9.6%)		Use 0.47*0.096= 4.5% for Δ oil CO_2	3.52
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484	
Judy Creek WF Area	48.03	6 (13%) WF		Use 0.484*0.13= 6.29% for Δ oil CO_2	2.90

In a similar manner, the estimated CO_2 EOR potential for the remaining BHL analogue pools was determined.

5.3.1.2 Judy Creek BHL B Pool

Estimated incremental CO_2 EOR recovery for the Judy Creek BHL B pool is provided in Table 5.3.1.6. For Judy Creek B Pool, a realistic combined incremental reserves target for WF+HCMF areas is 1.5 million m^3.

Table 5.3.1.6: Estimated incremental CO_2 EOR for Judy Creek BHL B Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF oil decline curve or for WF from simulation 10^6m^3 (RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10_3m^3/d/i.w.
SFA-1	34.57	1.1 (3.2%)	3.1%	0.97		500 (inj.) 250 (prod.)
Judy Creek B HCMF Area	28.37	1.25 (4.4%)		Use 0.97	1.21	600 (inj) 325 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Judy Creek B-WF area	11.36	2.73 (24%) ERCB-WF		Use 0.484 or 11.6% for Δ oil CO_2	1.32	

5.3.1.3 Carson Creek North BHL A&B Pool

Table 5.3.1.7 provides estimated incremental CO_2 EOR for the Carson Creek North BHL A&B pool. Based on WFA2, the predicted incremental CO_2 EOR for Carson Creek North is 9.7 million m^3. Because large areas of Carson Creek are of poor quality, this may be high.

Table 5.3.1.7: Estimated Incremental CO_2 EOR for Carson Creek North BHL A & B Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 (RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Carson Creek North	56.93	20.04(35.2%) ERCB-WF		Use 0.484 or 17.0% for Δ oil CO_2	9.7	600 (inj.) 400 (prod.)

5.3.1.4 Goose River BHL A Pool

The solvent flooded area of Goose River BHL A pool is the NW part of the pool, which though covering less than half the area of the pool, has contributed about 75% of the total oil production, including a similar proportion of incremental ultimate tertiary oil reserves. This area can be flooded by CO_2 utilizing existing wells via four 9-spot patterns, each covering 96 ha (240 acre). Table 5.3.1.8 gives the estimated incremental CO_2 EOR oil for the Goose River BHL A pool.

Table 5.3.1.8: Estimated incremental CO_2 EOR for Goose River BHL A Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 (RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
SFA-3	17.66	1.0 (5.7%)	2.7%	0.47		1000 (inj.) 150 (prod.)
Goose R. SF Area	16.16	1.13 (7%) ERCB		Use 0.47*0.07	0.53	350 (inj.) 250 (Prod.)
WFA-3	7.342	41.0	20.8%	0.507		200 (inj.) 300 (prod.)
Goose R. WF Area	9.341	2.15 (23%) ERCB-WF		Use 0.507*0.23	1.09	300 (inj.) 200 (Prod.)

5.3.1.5 Kaybob BHL A Pool

Table 5.3.1.9 gives the estimated incremental CO_2 EOR oil for the Kaybob BHL A pool. From geology and performance, Swan Hills WFA-4 is the appropriate prototype but it is deeply influenced by fluid encroachment from adjoining areas. WFA-2 is the next best prototype; using WFA2 the incremental CO_2 recovery for Kaybob waterflood area is 2.09 million m^3.

Table 5.3.1.9: Estimated incremental CO_2 EOR for Kaybob BHL A Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 (RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
SFA-3	17.66	1.0 (5.7%)	2.7%	0.47		1000 (inj.) 150 (prod.)
Kaybob SF Area	36.83	2.0 (5.43%)		Use 0.47*.0543	0.94	300 (inj.) 75 (Prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Kaybob WF Area	11.29	2.71 (24%) ERCB-WF		Use 0.484*0.24	1.31	250 (inj.) 70 (Prod.)

5.3.1.6 Simonette BHL A Pool

Table 5.3.1.10 gives the estimated incremental CO_2 EOR oil for the Simonette BHL A pool. From geology and performance, Swan Hills WFA-4 is the appropriate prototype but it is deeply influenced by fluid encroachment from adjoining areas. WFA-2 is the next best prototype. Based on WFA4, the predicted incremental CO_2 EOR for Simonette waterflood area is 2.11 million m^3.

Table 5.3.1.10: Estimated incremental CO_2 EOR for Simonette BHL A Pool

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 (RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Simonette BHL A	9.162	2.75 (30%) ERCB-WF		Use 0.3*0.484	1.33	300 (inj.) 200 (Prod.)

5.3.1.7 Snipe Lake BHL A Pool

Geological assessment indicated that Snipe Lake BHL A would be an analogue of Redwater D-3. It is assumed that distribution of various facies in Snipe Lake is similar to that in Redwater D-3 reservoir. At

Redwater, original oil-in-place in the A1 (Fore Reef), A2 (Back reef) and A3 (lagoonal) facies was roughly distributed in ratios of 1: 1.4: 1.

Performance of the Snipe Lake reservoir does not very much resemble the performance of Redwater; recall that Redwater is an immiscible flood. Also, Redwater production is much more dominated by influx from the underlying aquifer. The overall production performance is closer to that in Swan Hills WFA-2 area, where incremental oil production by simulation was 20.7% vs. 42.8% for water flood (including contributions due to outside interference). Based on ratios between incremental recoveries due to EOR and waterflood, incremental oil recovery for Snipe Lake is indicated to be 0.23*0.0.484=11.1%.

Table 5.3.1.11: Estimated incremental CO_2 EOR for Snipe Lake BHL A

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Snipe Lake	31.00	7.13 (23%) ERCB-WF		Use 0.484*0.23	3.45	75 (inj.) 40 (prod.)

5.3.1.8 Swan Hills South BHL A & B Pools

Table 5.3.1.12: Estimated incremental CO_2 EOR for Swan Hills South BHL A & B Pools

EOR Study Area	OOIP 10^6m^3	Indicated Δ HCMF [WF] oil by decline curve 10^6m^3 RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 10^6m^3	Processing Rates during WF/SF 10^3m^3/d/i.w.
SFA-1	34.57	1.1 (3.2%)	3.1%	0.97		500 (inj.) 200 (prod.)
Swan Hills South HCMF Area	138.8	7.0 (5.04%)		Use 0.97*0.0504	6.8	500 (inj.) 325 (prod.)

5.3.1.9 Virginia Hills BHL A & B Pools

The north-west area of the pool has not been solvent flooded. This area is a target for CO_2 following waterflooding. From extrapolation of the water cut versus cumulative oil curve, these five patterns would produce 3.5 million m^3 incremental oil due to tertiary solvent flooding.

The CO_2 flood area after HCM solvent flood can be developed on five 9-spots drilled on 16 ha/well (40 acre/well) spacing. During quaternary CO_2 injection, it is estimated that they would produce 3.4 million m^3 incremental oil over 40 years for one HCPV of CO_2 injection.

Table 5.3.1.13: Estimated incremental CO_2 EOR for Virginia Hills BHL A Pool

EOR Study Area	OOIP $10^6 m^3$	Indicated Δ HCMF [WF] oil by decline curve $10^6 m^3$ (RF%)	Δ oil due to CO_2 (RF%) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 $10^6 m^3$	Processing Rates during WF/SF $10^3 m^3$/d/i.w.
SFA-1	34.57	1.1 (3.2%)	3.1%	0.97		500 (inj.) 200 (prod.)
Virginia Hills HCMF Area	35.34	3.5 (9.9%)		Use 0.97*0.099	3.4	500 (inj) 325 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Virginia Hills WF Area	38.93	4.827 (12.4%) WF ERCB		Use 0.726*0.124	3.5	350 (inj.) 125 (prod.)

5.3.1.10 Ante Creek BHL

Ante Creek is a 'linear' pool, with wells in the NW portion performing much better than in the SW portion. Much of water and hydrocarbon solvent injection has occurred in this area. Largest amount of solvent was injected in the well 10-07-65-23W5M, located in the South-central part but did not significantly improve oil recovery in the offset wells. However, water injection which began in 1969, was altogether discontinued in 1997 and the total fluid production has been steadily declining and GOR increasing since then. Very likely, reservoir pressure has declined and the reservoir would need to be re-pressurized ahead of CO_2 injection. The combined incremental recovery factor of 23% OOIP for water and solvent flood makes this a rather poor prospect for CO_2 injection, compared to other BHL pools.

5.3.2 D2/D3 Pools

Prototype Pool/Areas Selected

Redwater D3 was selected as the prototype reservoir to be studied in detail. Prototype areas were defined by including nine-spot flooding patterns comprising wells drilled on 16 ha spacing on the fore-reef (Eastern edge), reef build-up (central portion of the pool) and lagoon dominated regions to the west.

Analogous Pools/Areas

These types of pools are characterized by sustained strong oil rate performance until a majority of their ultimate oil reserves are produced (typically >70%). Some major pools of this type in Alberta are:

Bonnie Glen D-3A
Joffre D-2
Leduc-Woodbend D-2A
Fenn-Big Valley D-2A
Sturgeon Lake South D-3
Sturgeon Lake D-3

Rationale for Selecting Prototype Areas

Geological Features

All the above pools are carbonate reefs with regions dominated by

a. relatively thin fore-reef pay,
b. main reef build-up regions where pay becomes thick and,
c. relatively poor quality back-reef/lagoonal areas.

Performance Aspects of Redwater and Analogous Pools

After major water-breakthrough, water-cuts rapidly increase even after installing high volume lifting devices and disposing of the produced water within the pay horizon. Economic oil rates could not be sustained thereafter, leaving behind about half or more of the original oil unrecovered.

By the time of implementing CO_2 flooding (2013), most wells would have been essentially watered out (typically, WOR>150). The main EOR targets regions will be bypassed or would contain residual oil saturation within watered out pay intervals. There is generally relatively high injectivity/productivity at different wells and hence, each injector could support more than one producer.

If there are no barriers to vertical flow (or if unbroken, continuous pay interval exceeds 15 m), a vertical CO_2 flood yielding high recovery may become feasible in some areas. However, looking at various pools, such opportunities appear to be very limited. Hence seven-spot or nine-spot patterned (horizontal flood) mode of exploitation appears feasible in most of these pools.

Extrapolation Methodology

Rationale

Since the performance of the pools (history in terms of oil rate and water-oil ratio) is very similar for these pools and the main EOR target is residual oil, it is surmised that empirical methods based on similarity principles would provide reasonable estimates of performance for various analogous pools. Results based on reservoir simulation for the prototype pool (Redwater D-3) were therefore used to develop the desired estimates. This approach was described in more detail in Section 5.3.1.

Limitations

EOR at Redwater D-3 via CO_2 injection will be in immiscible mode with a strong component of vaporization. At most other pools, miscible flooding may be feasible. Also, production contribution due to the aquifer may be different for different pools due to differences in reservoir quality, aquifer strength, and previous exploitation strategy.

Redwater Analogue Pools

Minimum miscibility pressures (MMP) for CO_2 flooding have been determined for the D2/D3 analogues as shown in Table 5.3.2.1.

Table 5.3.2.1: Pressures and Recovery Factors of D-2/D-3 Analogue Pools

Pool	Initial Pressure MPa	Current Pressure MPa	MMP for CO_2 Flood (MPa)	Current Recovery Factor (ERCB)
Fenn Big Valley D-2A	12.88	11.4	13.99	0.63
Joffre D-2	17.38	15.9	12.86	0.3
Leduc Woodbend D-2A	12.58	5.3	12.23	0.427
Meekwap D-2A	21.62	20.5	15.56	0.58
West Drumheller D-2A	13.19		10.50	0.55
Bonnie Glen D-3A	17.3	6.38	13.36	0.67
Leduc Woodbend D-3A	13.261	10.5	12.06	0.76
Morinville D-3B	12.65		13.80	0.55
Redwater D-3	7.40		8.47	0.65
Sturgeon Lake D-3	26.97	22.3	12.26	0.35
Sturgeon Lake South D-3	27.24	21.20	15.78	0.59

Based on comparison of initial pressure (P_i) and MMP, Fenn Big Valley D-2A and Morinville D-3B will be immiscible with CO_2. Redwater will be a reasonable analogue. The remaining pools are miscible based on initial pressure. However, both Bonnie Glen D-3A, Leduc Woodbend D-2A and Leduc Woodbend D-3A are currently below MMP, so Redwater would be a reasonable analogue for them as well. It may be possible to repressure the pools by injection of water prior to conducting CO_2 flooding.

Solution gas drive is a principal mechanism for primary recovery but these pools all have a large aquifer beneath so some component of water influx likely occurs during exploitation. The ERCB classifies the recovery mechanisms of the pools as "primary", and for most, carries very large ultimate recovery factors (Table 5.3.2.1), suggesting a considerable contribution to recovery due to water influx. For purposes of extrapolation to analogue pools, a ratio of 1:3 has been used to reflect the relative influence of the solution gas drive and water influx mechanisms, respectively. Thus, for those pools that can be flooded miscibly, the incremental water influx (flood) based on the above ratio has been used to estimate incremental recovery. Thus, the “water influx” recovery factor has been set at 0.75 of the ERCB recovery factor. For the pools that can be flooded miscibly, WFA2 was used as a prototype.

5.3.2.1 Bonnie Glen D-3 A Pool

The Bonnie Glen D-3 A Pool, discovered in 1951, is the second-largest Woodbend oil field. The pool is an isolated dolomite reef in the Rimbey-Meadowbrook Reef Trend. Discovery pressure (17.3 MPa) was higher than MMP (13.4 MPa). However, pressure has declined below MMP to 6.4 MPa. Unless the reservoir is repressured, this will be a target for immiscible flood by CO_2. So Redwater is close to an ideal prototype.

Table 5.3.2.2: Estimated incremental CO_2 EOR for Bonnie Glen D-3A (Immiscible flood)

EOR Study Area	OOIP ($10^6 m^3$)	Indicated Δ water influx/ flood ($10^6 m^3$/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 ($10^6 m^3$)	Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Bonnie Glen D-3A	125.0	82.7 (67%) ERCB		Use RW 0.75*0.67*0.076 or 3.82% for Δ oil CO_2	4.77	300 (inj.) 100 (prod.)

5.3.2.2 Sturgeon Lake D-3A Pool

The Sturgeon Lake D-3A Pool is located at the northeast, windward margin of a large dolomite reef complex located in the West Shale Basin. Assessment is given in Table 5.3.2.3.

Table 5.3.2.3: Estimated incremental CO_2 EOR for Sturgeon Lake D-3

EOR Study Area	OOIP ($10^6 m^3$)	Indicated Δ water influx/ flood ($10^6 m^3$/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 ($10^6 m^3$)	Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Sturgeon Lake D-3	13.55	4.74 (35%) ERCB		Use WFA2 0.75*0.35*0.484 or 12.7% for Δ oil CO_2	1.72	700 (inj.) 150 (prod.)

5.3.2.3 Sturgeon Lake South D-3 A Pool

The Sturgeon Lake D-3A Pool is located at the southeast, windward margin of a large dolomite reef complex located in the West Shale Basin. Cadence Energy Inc., the current operator of the pool, has been studying to possibility of a CO_2 flood in the pool.

Table 5.3.2.4: Estimated incremental CO_2 EOR for Sturgeon Lake South D-3A

EOR Study Area	OOIP ($10^6 m^3$)	Indicated Δ water influx/ flood ($10^6 m^3$/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 ($10^6 m^3$)	Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Sturgeon Lake South D-3	46.07	27.18 (59%,) ERCB		Use 0.75*0.59*0.484 or 21.4% for Δ oil CO_2	9.87	700 (inj.) 300 (prod.)

5.3.2.4 Leduc-Woodbend D-3 A Pool

The Leduc-Woodbend D-3 A Pool is a large isolated dolomite reef in the Rimbey-Meadowbrook Reef Trend. The pool is under waterflood. Swan Hills water-flooded area WFA2 is a reasonable geological analogue for the Leduc-Woodbend D-3 A Pool, but Swan Hills is a limestone reservoir, and Leduc-Woodbend is a dolomite reservoir. Further, since current pressure is below MMP, Redwater the more appropriate analogue. It may be possible to raise pressure by water injection to move closer to a miscible flood, but since more than 75%OOIP has already been recovered the added potential due to miscible flooding may be small.

Table 5.3.2.5: Estimated incremental CO_2 EOR for Leduc Woodbend D-3A

EOR Study Area	OOIP ($10^6 m^3$)	Indicated Δ water influx/ flood ($10^6 m^3$/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 ($10^6 m^3$)	Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Leduc Woodbend D3A	52.65	40.0 (64% primary and 12%, WF) ERCB		Use 0.75*0.76*0.076 or 4.35% for Δ oil CO_2	2.28	300 (inj.) 150 (prod.)

5.3.2.5 Fenn Big Valley D-2 A Pool

Table 5.3.2.6: Estimated incremental CO_2 EOR for Fenn Big Valley D2A with Isolated Associated Gas cap (Horizontal Miscible flood)

EOR Study Area	OOIP (10^6m^3)	Indicated Δ water influx/ flood (10^6m^3/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 (10^6m^3)	Processing Rates during WF/SF (10^3m^3/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Fenn Big Valley D2A (WF area)	74.2	46.7 (63%,) ERCB		Use 0.75*0.63*0.076 or 3.59% for Δ oil CO_2	2.66	300 (inj.) 150 (prod.)
Fenn Big Valley D2A (SF Area)	5.8	0.30 (5.2%) SF (ERCB)		Use 0..076*5.2 or 2.5% for Δ oil CO_2	0.023	250 (inj.) 100 (Prod.)

Redwater is close to a proper prototype (very strong water drive) since this would be an immiscible CO_2 flood. A HCMF pilot was conducted in part of the pool earlier in its history and recovered approximately 5%OOIP. However, it is likely that any CO_2 flood will be immiscible. Total recovery from both areas will total approximately 2.7 million m_3.

5.3.2.6 Leduc Woodbend D-2 A Pool (Horizontal Miscible Flood)

Table 5.3.2.7: Estimated incremental CO_2 EOR for Leduc Woodbend D2A (Horizontal Miscible flood)

EOR Study Area	OOIP (10^6m^3)	Indicated Δ water influx/ flood (10^6m^3/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 (10^6m^3)	Processing Rates during WF/SF (10^3m^3/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Leduc Woodbend D-2A	32.7	46.7 (32.7% primary and 10%, WF) ERCB		Use 0.75*0.427*0.484 or 15.5% for Δ oil CO_2	5.07	50 (inj.) 15 (prod.)

5.3.2.7 Meekwap D-2 Pool

Table 5.3.2.8: Estimated incremental CO_2 EOR for Meekwap D2 Pool						
EOR Study Area	**OOIP ($10^6 m^3$)**	**Indicated Δ water influx/ flood ($10^6 m^3$/RF%)**	**Δ oil due to CO_2 (%RF) (simulation)**	**Ratio of Δ oil CO_2/Δ oil HCMF**	**Inferred Δ oil due to CO_2 ($10^6 m^3$)**	**Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)**
EOR Study Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Meekwap D2A	11.81	6.85 (20% primary and 38% WF) ERCB		Use 0.75*0.58*0.076 or 3.30% for Δ oil CO_2	0.39	600 (inj.) 250 (prod.)

5.3.2.8 West Drumheller D-2B Pool

Table 5.3.2.9: Estimated incremental CO_2 EOR for West Drumheller D2B (Horizontal Miscible flood)						
EOR Study Area	**OOIP ($10^6 m^3$)**	**Indicated Δ water influx/ flood ($10^6 m^3$/RF%)**	**Δ oil due to CO_2 (%RF) (simulation)**	**Ratio of Δ oil CO_2/Δ oil HCMF**	**Inferred Δ oil due to CO_2 ($10^6 m^3$)**	**Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)**
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
West Drumheller D2A	8.905	4.898 (55% primary) ERCB		Use 0.75*0.55*0.484 or 20.0% for Δ oil CO_2	1.78	150 (inj.) 30 (prod.)

5.3.2.9 Joffre D-2 Pool

Table 5.3.2.10: Estimated incremental CO_2 EOR for Joffre D-2 Pool						
EOR Study Area	**OOIP ($10^6 m^3$)**	**Indicated Δ water influx/ flood ($10^6 m^3$/RF%)**	**Δ oil due to CO_2 (%RF) (simulation)**	**Ratio of Δ oil CO_2/Δ oil HCMF**	**Inferred Δ oil due to CO_2 ($10^6 m^3$)**	**Processing Rates during WF/SF ($10^3 m^3$/d/i.w.)**
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
WFA-2	8.71	3.73 (42.8%)	20.1%	0.484		1000 (inj.) 300 (prod.)
Joffre D2	26.65	7.996 (25% primary and 5% WF) ERCB		Use 0.75*0.30*0.484 or 10.9% for Δ oil CO_2	2.90	80 (inj.) 10 (prod.)

5.3.2.10 Morinville D-3 B Pool

The Morinville D-3 B Pool is a located at the eastern, windward margin of the north-south trending dolomite Morinville Trend (the northerly continuation of the Rimbey-Meadowbrook Reef Trend). There were a total of 18 wells but most of the time 4 or fewer wells were on production and out of two injection wells, at any given time, only one was being used for water disposal. Currently, two wells are producing. The pressure in the reservoir is being maintained, in part by water disposal and also, most likely by water influx. However, initial pressure was less than MMP so CO_2 flood will likely be immiscible.

Table 5.3.2.11: Estimated incremental CO_2 EOR for Morinville D-3B Pool

EOR Study Area	OOIP (10^6m^3)	Indicated Δ water influx/ flood (10^6m^3/RF%)	Δ oil due to CO_2 (%RF) (simulation)	Ratio of Δ oil CO_2/Δ oil HCMF	Inferred Δ oil due to CO_2 (10^6m^3)	Processing Rates during WF/SF (10^3m^3/d/i.w.)
Redwater	229.55	135 (59%)	4.44%	0.076		3000 (inj.) 400 (prod.)
Morinville D3B	3.318	1.82 (55%) ERCB		Use 0.75*0.55*0.076 = 0.031 for Δ oil CO_2	0.104	400 (inj) 200 (prod.)

5.3.3 Cardium Pools

The largest Cardium target is the huge Pembina Cardium field. More than two thirds of the 1.3 billion m^3 of oil-in-place in the Pembina Cardium deposits has been subjected to water flooding. By and large, areas with thicker (>7 m) net pay and water injectivity exceeding 5 m^3/d/well (vertical) have been water flooded.

Overall recovery factor of 10% for primary and an additional 10% for water flooding have been assigned by ERCB. There is a great deal of heterogeneity within and amongst various water flooding Units in the Pembina field. This is reflected in average productivity, injectivity and recovery factors for individual Units. Interestingly, solution gas recovery was estimated at about 50%, indicating a significant amount of reservoir would remain unexploited by primary depletion and water flooding.

Past solvent flooding and immiscible gas flooding operations met with partial success, perhaps due to limitations in the available production technology, understanding of reservoir heterogeneity and recovery mechanics and prevailing economic conditions at the time of these tests.

General Methodology

The standardized methodology used to extrapolate performance from the analogues was to examine Oil Cut vs. Cumulative oil plotted on three cycle semi-log graph, so that the shapes of these curves could be compared to each other.

Assumptions/Speculations/ Observations about Past Production Trends

- Lateral heterogeneity=continuity=areal sweep
- Vertical stratification can be represented by Dykstra-Parsons coefficient.
- Primary reserves are contributed by all intervals. Very tight intervals like Sand 4 (with permeability < say, 5 md, especially in presence of other intervals of much higher permeability) are unlikely to contribute to waterflood or EOR. Although Sand 3 contains certain streaks with permeability exceeding 5 md, their potential EOR contribution may be ignored compared to Cardium sands 4, 5/6 and Conglomerate.
- Primary production contributions may continue for up to say, 20 years upon initiating waterflood. Likewise, at current state of water flooding (~45 years of water flooding and oil-cut) in most EOR Target areas of less than 10%; waterflood production contributions would continue for another 20 years.
- Stalling of decline in oil-cut vs. cumulative oil is an indicator of progression of volumetric sweep.
- Decreasing of injection rates promotes redistribution and spread of injected fluids.
- Most infill wells promote volumetric sweep but on occasions, some infill injectors/producers may actually be promoting short-circuiting of injected fluids.

- Performance may also be somewhat influenced by optimizing interventions such as redistributing injection-production, including shutting in of 'non-performing' injector and producer wells.

Oil-Cut vs. Cumulative Oil as Basis for Analogue Grouping

Oil-cut vs. cumulative oil curves generally provide good diagnostics of performance of waterfloods and EOR. They reflect how the injected fluids are sweeping the project area. These curves are generally unaffected by changes in water handling capabilities or well counts, although the shape of these curves may be somewhat affected by optimizing actions (e.g. infill wells, shutting in of high water producers, increasing or decreasing flooding rates).

A steep decline denotes very inefficient sweep, whereby the injected fluid essentially recycles after a short period, reflecting thief intervals (or regions) between injectors and producers.

For the 15 Pembina waterfloods reviewed, where the peak injection/production rates per well were strong (on the average, exceeding 15 m^3/d/well), no true thief-zone-dominating floods were seen. Roughly speaking, these floods can be divided in two groups. In Group I, the oil cut monotonically declines. In Group II, the decline in oil rates is stalled, indicating spreading of the sweep without undue decreases in oil cut. The former is generally associated with regions with prolific conglomerate and the latter without.

The amount of cumulative oil produced prior to seeing decrease in oil cut reflects strong primary production aided by generally good volumetric sweep prior to water breakthrough. It may be recalled that most of these floods were initiated in late 1950's/ early 1960's before the start of ERCB production databases. It may also be pointed out that although the Lower Pembina Sand (Sand 3) may contain some high quality pay intervals, it is generally seen to be contributing to oil production during the primary production only (other pay intervals have considerably higher flow capacities). Therefore, the ratio between oil produced while oil cut is essentially 100% and the ultimate oil produced (oil-cut vs. cumulative oil curve extrapolated to 1% oil-cut), reflects the proportion of pay intervals not contributing to waterfloods along with volumetric sweep in the more prolific intervals (Sands 4, 5/6 and Conglomerate).

The similarity of these curves during water flooding suggests that the fractional flow curves can be modified, taking into account, 'connectivity' within the reservoir (or, Dykstra-Parson coefficients). Note that this 'connectivity' during water floods will be higher than that during CO_2 flood (since CO_2 has a higher mobility than water). For sensitivity runs, modifications to thicknesses/permeabilities in the models by appropriate factors can be made.

A prototype area representative of the performance characteristics and geological features of the analogue area was selected. The performance of the prototype area [ratio $\Delta RF(CO_2)/\Delta RF(WF)$] was used as a factor to predict the expected CO_2 EOR reserves for the analogue areas. Table 5.3.3.1 provides the performance characteristics of the prototype areas based on simulation.

Table 5.3.3.1: Performance of Simulated Cardium Prototype Areas					
Category	Area #	OOIP (10^6 m^3)	RF (WF)	RF (CO_2)	ΔRF(CO_2)/ ΔRF(WF)
Thief Zone Present					
	NPCU subarea # 2	9.104	0.086	0.181	2.105
	3	6.232	0.133	0.179	1.346
	4	10.520	0.092	0.140	1.522
	5	23.276	0.053	0.180	3.396
	6	3.962	0.116	0.093	0.802
	8	17.191	0.100	0.176	1.760
No Thief Zone Present					
	1 ('A' Lease)	30.482	0.239	0.130	0.544

5.3.3.1 Pembina Southern Areas (Pembina Cardium Units 2 & 8)

An area to the South of the NPCU-1 Unit in Twp 47 and 48, Range 7 and 8, W5M was identified as an area with significant CO_2 EOR potential, and a geological model of the area was constructed to perform additional simulation parametric studies and extrapolations. The model was constructed using geological tops and core data from the Divestco GeoVista database (Figure 5.3.3.1). In some areas the accuracy of the model is limited due to inconsistent "picks" in the Cardium Formation in the GeoVista database. Three subareas were defined based on geological parameters and production performance: S1 to the north, S2 in the center, and S3 to the south. Reservoir parameters were calculated for each of the subareas for parametric studies and extrapolations (Table 5.3.3.2). We refer to this area as Pembina "South" and it encompasses parts of Cardium Units 2 and 8.

Table 5.3.3.2: Geological parameters for area south of NPCU 1. Cut-offs: Conglomerate: 3 % porosity, 0.25 mD permeability; sands: 8 % porosity, 0.8 mD permeability.				
	Area	**Rock Volume With Porosity Cutoff**	**Pore Volume With Porosity Cut-off**	**Average Porosity: Calculated**
		m3	m3	fraction
Conglomerate	**S1**	6,011,450	752,420	0.13
	S2	4,924,142	583,616	0.12
	S3	20,490,082	2,072,094	0.10
	Total	31,425,674	3,408,130	0.11
4/5/6 Sand	**S1**	53,622,957	7,773,707	0.14
	S2	188,472,545	28,206,775	0.15
	S3	238,257,493	35,142,853	0.15
	Total	480,352,995	71,123,335	0.15
Lower Cardium	**S1**	382,391,039	43,449,325	0.11
	S2	402,409,969	43,271,008	0.11
	S3	389,419,883	45,716,292	0.12
	Total	1,174,220,891	132,436,625	0.11

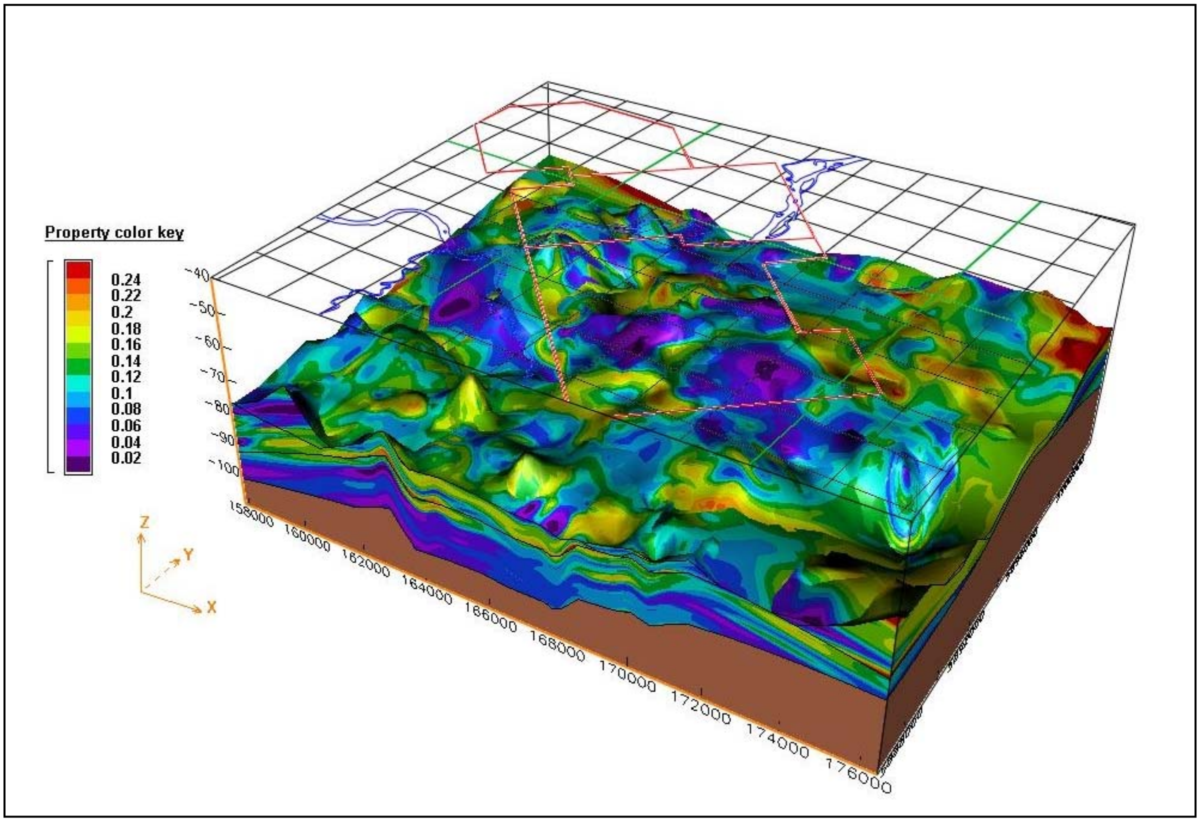


Figure 5.3.3.1: Block diagram showing porosity in Pembina area south of NPCU-1.

Northern Portion (S1)

This is the NW part of the prospective EOR area south of NPCU. It includes 30 current injectors and 44 current oil producers. Injectivity/productivity sharply deteriorates as we move towards Northern edges of the area. To the South-West, we could potentially add two additional patterns with good productivity/ injectivity (around injector's 08-05-048-8W5M at the edge of this area and 14-33-04708W5M). Some gas was injected in the past at 14-34-47-8-5 and wells 14-33 and 14-32 (to the west, outside this area), for which we can determine gas injectivity. Since 1962, cumulative oil production has been more than 3 times (aided by water flood), compared to pre-1962 cumulative oil production.

Central Portion (S2)

This is the central part of the prospective EOR area, located northwest of the river near the township line 47/48 and range line 7/8. It includes 49 current injectors and 92 current oil producers (some parts are developed on 40 acre spacing). Injectivity/productivity sharply deteriorates as we move towards Northern and southern edges of the area. To the South-West, we could potentially add two or three additional patterns with good productivity/injectivity. In general, injectivity/productivity deteriorates towards the Northern and Southern ends of the area. Since 1962, cumulative oil production has been more than 3.5 times (aided by water flood), compared to pre-1962 cumulative oil production.

Southern Portion (S3)

This is the Southern part of the prospective EOR area. It includes 63 current injectors and 160 current oil producers (some parts are developed on 40 acre spacing). Injectivity/productivity sharply deteriorates as we move towards the West of the area. To the South-West and Southeast, we could potentially add two or three additional patterns with reasonably good productivity/injectivity. Since 1962, cumulative oil production from the area has been about 3 times (aided by water flood), compared to pre-1962 cumulative oil production.

5.3.3.2 Berrymoor Unit

The Berrymoor Cardium Unit (Twp 49, Range 6, W5M) was also identified as an area with significant CO_2 EOR potential, and a geological model of the area was constructed to perform additional simulation parametric studies and extrapolations. The model was constructed using geological tops of the conglomerate, 4 Sand, and 3 Sand picked consistently from logs. Reservoir parameters were then calculated for parametric studies and extrapolations (Table 5.3.3.3).

The prospective EOR area within the Berrymoore Unit covers about 11 Sections and contains 122 wells, 19 of which are current injectors and 69 are current oil producers (most of this area is developed on 40 acre/well spacing). Injectivity/productivity sharply deteriorate as we move towards the northeast or southwest from central rows of wells, trending NW-SE.

Table 5.3.3.3: Properties of Berrymoor geological model

	Porosity Cut-off	Porosity Mode	Rock Volume with Porosity Cut-off	Pore Volume with Porosity Cut-off	Average Porosity Calculated
	%	fraction	m3	m3	fraction
Conglomerate	3%	0.13	25,167,549	2,930,806	0.12
4 Sand	3%	0.18	69,101,446	11,479,972	0.17
	8%	0.18	68,767,983	11,457,039	
3 Sand	3%	0.12	278,431,635	34,182,014	0.12
	8%	0.12	274,285,069	33,878,645	

There was limited oil production prior to 1962 although water injection had begun. By 1967, there were 11 injectors and 48 producers in this area. Since 1962, cumulative oil production from the area has been more than 20 times (aided by waterflood), compared to pre-1962 cumulative oil production.

Table 5.3.3.4 summarizes performance data, listed from the North to South for the Southern potential EOR areas in T 47/48, R 7/8, covering areas in and around PCU # 2 & 3 and also, for the Berrymoor Unit in T 49, R5/6:

Table 5.3.3.4: Performance data of Pembina southern EOR areas and Berrymoor					
Area	# Wells	Injectivity/well (m^3/d)	Productivity/well (m^3/d)	Water-Oil Ratio in 2013	Prim+WF Recovery million m^3
Northern (S1)	99	60	35	30	7
Central (S2)	169	35	25	20	10
Southern (S3)	258	40	15	15	16
Berrymoor	122	100	35	12.5	9

Table 5.3.3.5 provides the calculated incremental oil expected due to CO_2 flooding for the southern Pembina areas and Berrymoor based on the performance of the NPCU and A-lease prototype performance.

Prototype areas for Berrymoor and the Pembina southern areas were selected based on geological features of the areas as shown in Tables 5.3.3.1 and 5.3.3.2. Berrymoor had peripheral waterflood (due to the strong injectivity, relative to most other Pembina Cardium areas). Production distribution suggests it was quite effective. Table 5.3.3.6 provides the criteria used to assign prototype areas for comparison. Table 5.3.3.7 shows the determination of the CO_2 EOR recovery factor for each of the areas. Table 5.3.3.8 provides calculated CO_2 EOR reserves for other Pembina areas and Cardium analogues.

Table 5.3.3.5: Recovery factors for Pembina Southern EOR areas					
Area	PV[1] million m^3	OOIP[2] million m^3	Prim+WF ultimate Recovery million m^3	Recovery Factors[3] for only WF[4]	Incremental oil[5] due to CO_2 million m^3
Northern	51.98	37.89	7	0.085	4.9
Central	72.06	53.17	10	0.088	9.9
Southern	82.93	60.46	16	0.165	8.0
Berrymoor	48.59	35.42	9	0.154	6.5

[1]Used 3% porosity cut-offs
[2]Assumed 10% Connate Water and 0.81 shrinkage
[3]Assumed RF (Primary) = 10% OOIP
[4]Slightly over-estimated due to including entire production of boundary wells
[5]Refer to Table 5.3.3.4 (below) for estimation of recovery factors

Table 5.3.3.6: Prototypes for Pembina Southern EOR areas

Area	PV for Conglomerate million m^3	PV for 4/5/6 sand million m^3	PV for Lower Cardium million m^3	Recovery Factors for Water Flooding only	NPCU Prototype Area Selected
Northern	0.75	7.77	43.45	0.085	4
Central	0.58	28.21	43.27	0.088	2
Southern	2.07	35.14	45.72	0.165	6
Berrymoor	2.93	11.48	34.18	0.154	3

Table 5.3.3.7: Prototypes for Pembina Southern EOR areas

Area	NPCU Prototype Area Selected	Δ Recovery Factor for Water Flood in Prototype Area	Δ RF due to CO_2 in Prototype Area	Recovery Factors for Water Flooding (analogue)	ΔRF due to CO_2 in Analogue Area
Northern	4	0.092	0.14	0.085	0.13
Central	2	0.086	0.181	0.088	0.19
Southern	6	0.116	0.093	0.165	0.13
Berrymoor	3	0.133	0.179	0.154	0.21

Table 5.3.3.8: Data on Analogues (including from ERCB)

Analogue	OOIP (10^6 m^3)	RF (WF)	Reserves (WF) (10^6 m^3)	Prototype	ΔRF-CO_2/ ΔRF-WF (Prototype)	Δ Reserves in Analogue for CO_2 Flooding (10^6 m^3)
Ferrier Belly River Q/ Cardium G & L	73.840	0.15	11.084	'A' Lease Subarea # 1	0.544	6.0
Carrot Creek Cardium F	5.286	0.17	0.899	NPCU Subarea # 4	1.522	1.37
Cyn-Pem Cardium A	6.410	0.24	1.538	NPCU Subarea # 6	0.802	1.23
Cyn-Pem Cardium D	7.500	0.38	2.850	NPCU Subarea # 6	0.802	2.29
Cynthia Unit # 2	6.88		4 (P+WF)	NPCU Subarea # 3	1.346	1.23
Bear Lake (Pembina)	5.71		3.3 (P+WF)	NPCU Subarea # 4	1.522	1.75
Lobstick (Pembina)	37.9		5 (P+WF)	NPCU Subarea # 3	1.346	7.08

Notes: The last three targets, namely Cynthia Unit # 2, Bear Lake and Lobstick are conglomerate (thief zone) dominated, have relatively high injectivities and productivities. For these, in absence of data on OOIP and primary reserves, primary recovery factor was assumed to be 20% and projections for CO_2 flooding were based on ratios between RF(CO_2)/RF (P+WF) at the respective prototypes.

5.4 CO_2 Requirement and Storage for Prototypes and Analogues

The CO_2 requirement for each analogue pool was established based on the HCPV of CO_2 injected and produced in the corresponding prototype area. The properties of CO_2 for each analogue pool were determined based on the pressure and temperature of the pool in order to calculate the amount of CO_2 to be injected in each analogue. Note that the total OOIP studied for BHL Lake and Pembina groups is less than the total OOIP in the waterflood and solvent flood areas of the pools (Table 5.3.1). The study areas have been "high graded" to include those most likely to have successful EOR. The high graded areas have 1840.7 million m^3 (11578 million bbl) original-oil-in-place.

5.4.1 Beaverhill Lake Prototypes and Analogues

Tables 5.4.1 summarizes the results for the assessment of the BHL pools studied. For the BHL target pools, potential CO_2 EOR would be 55.6 million m^3 (350 million bbl). Total injection of CO_2 including recycle would be 360.2 Mt. giving a gross CO_2 utilization of 6.48 t/m^3 (19.6 mcf/bbl). A total of 99.2 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.78 t/m^3 (5.39 mcf/bbl). Essentially all of the purchased CO_2 is expected to be retained (stored) in the BHL pools at the end of the project life.

Table 5.4.1: CO_2 Requirement and Storage for BHL Prototypes and Analogues-No Risk Factor

Field/Pool	Recovery Process	OOIP[2]	Predicted EOR Oil Recovery	CO_2 Injected	CO_2 Purchased[1]	CO_2 Utilization		
		10^3m^3	10^3m^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
Ante Creek BHL	SF	5931	580	2.47	0.57	4.25	0.97	2.9
Carson Creek North BHL A & B	WF	56930	9700	54.2	16.9	5.59	1.74	5.3
Goose River BHL A	SF	16160	530	6.11	1.40	11.53	2.64	8.0
Goose River BHL A	WF	9341	1090	6.72	2.10	6.16	1.92	5.8
Judy Creek BHL A	SF	77950	3520	26.7	6.11	7.58	1.74	5.2
Judy Creek BHL A	WF	48030	2900	24.25	7.56	8.36	2.61	7.9
Judy Creek BHL B	SF	28370	1210	11.13	2.55	9.20	2.11	6.4
Judy Creek BHL B	WF	11360	1320	7.67	2.39	5.81	1.81	5.5
Kaybob BHL A	SF	36830	940	17.43	3.99	18.54	4.24	12.8
Kaybob BHL A	WF	11290	1310	10.0	3.13	7.66	2.39	7.2
Simonette BHL A	WF	7764	1330	14.2	4.44	10.69	3.34	10.1
Snipe Lake BHL	WF	36600	3450	18.5	5.78	5.37	1.67	5.1
Swan Hills BHL A & B (SF prototype)	SF	149435	4539	45.2	10.3	9.96	2.28	6.9
Swan Hills BHL A & B (WF prototype)	WF	43547	9486	39.9	12.5	4.21	1.31	4.0
Swan Hills South BHL A & B	SF	138800	6800	38.5	8.81	5.66	1.30	3.9
Virginia Hills BHL	SF	35340	3400	10.87	2.49	3.20	0.73	2.2
Virginia Hills BHL	WF	38930	3500	26.24	8.19	7.49	2.33	7.1
Sub-total for WF group	**WF**	**263,792**	**34,086**	**201.8**	**63.0**	**5.92**	**1.85**	**5.6**
Sub-total for SF group	**SF**	**488,816**	**21,519**	**158.4**	**36.2**	**7.36**	**1.68**	**5.1**
Total		**752,608**	**55,605**	**360.2**	**99.2**	**6.48**	**1.78**	**5.4**

[1] CO_2 purchased (and hence "net" utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.
[2] Build-up only as used in this study

5.4.2 D2/D3 Prototypes and Analogues

Table 5.4.2 summarizes CO2 requirement and storage for the D-2/D-3 target pools. Potential CO_2 EOR would be 44.4 million m^3 (279 million bbl). Total injection of CO_2 including recycle would be 277 Mt giving a gross CO_2 utilization of 6.24 t/m^3 (18.9 mcf/bbl). A total of 82 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.85 t/m^3 (5.60 mcf/bbl). Essentially all of the purchased CO_2 is expected to be retained (stored) in the D-2/D-3 pools at the end of the project life.

Table 5.4.2: CO_2 Requirement and Storage for D-2/D-3 Prototype and Analogues-No Risk Factor

Field/Pool	OOIP	Predicted EOR Oil Recovery	CO_2 Injected	CO_2 Purchased[1]	CO_2 Utilization		
	10^3m^3	10^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
Fenn Big Valley D-2A	74200	2700	46.2	13.4	17.1	4.97	15.0
Joffre D-2	26650	2900	11.8	3.69	4.08	1.27	3.8
Leduc Woodbend D-2A	32700	5.07	12.2	3.80	2.40	0.75	2.3
Meekwap D-2A	11810	390	9.26	2.69	23.7	6.91	20.9
West Drumheller D2A & B	8905	1780	3.74	1.17	2.10	0.66	2.0
Bonnie Glen D-3A	125000	4770	56.1	16.3	11.7	3.42	10.4
Leduc Woodbend D-3A	52650	2280	32.6	9.50	14.3	4.17	12.6
Morinville D-3B	3318	104	1.71	0.50	17.1	4.97	15.0
Redwater D-3	207000	12778	60.0	17.5	4.85	1.37	4.2
Sturgeon Lake D-3A	13550	1720	9.81	3.06	5.70	1.78	5.4
Sturgeon Lake South D-3	46070	9870	33.3	10.4	3.38	1.05	3.2
Total	**601,853**	**44,360**	**276.7**	**82.0**	**6.24**	**1.85**	**5.6**

[1] CO_2 purchased (and hence "net" utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.

5.4.3 Cardium Prototypes and Analogues

The Pembina Cardium field contributes the bulk of the CO_2 EOR for the Cardium group. For Pembina Cardium, potential CO_2 EOR would be 60.1 million m^3 (378 million bbl). Injection of CO_2 including recycle would be 214 Mt giving a gross CO_2 utilization of 3.56 t/m^3 (10.8 mcf/bbl). A total of 54.2 Mt of purchased CO_2 would be required giving net CO_2 utilization of 0.90 t/m^3 (2.73 mcf/bbl). Essentially all of the purchased CO_2 is expected to be retained (stored) in the Pembina Cardium at the end of the project life.

For the combined Pembina Cardium and Cardium analogues assessed, the total potential CO_2 EOR would be 71.4 million m^3 (449 million bbl). Injection of CO_2 including recycle would be 296 Mt giving a gross CO_2 utilization of 4.15 t/m^3 (12.6 mcf/bbl). A total of 71.9 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.01 t/m^3 (3.06 mcf/bbl). Essentially all of the purchased CO_2 is expected to be retained (stored) in the Cardium protoypes and analogues at the end of the project life.

Table 5.4.3: CO_2 Requirement and Storage for Pembina Prototypes and Analogues-No Risk Factor

Field/Pool	OOIP	Predicted EOR Oil Recovery	CO_2 Injected	CO_2 Purchased[1]	CO_2 Utilization		
	10^3m^3	10^3m^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
NPCU & PCU 20 (Pembina with TZ prototype)	66,900	11,209	36.9	10.4	3.29	0.93	2.8
A Lease & Cynthia Unit 3 (Pembina no TZ prototype)	59,700	7,673	68.5	13.9	8.93	1.81	5.5
Pembina Bear Lake	5,710	1,800	2.52	0.71	1.40	0.40	1.2
Pembina Berrymoor	35,400	6,530	15.7	4.43	2.40	0.68	2.1
Pembina Cynthia Unit 2	6,880	1,230	6.08	1.24	4.95	1.00	3.0
Pembina Lobstick	37,900	7,080	11.3	3.21	1.60	0.45	1.4
Pembina Cardium South (Units 2 & 3)							
Area S1	37,900	4,900	16.8	4.74	3.42	0.97	2.9
Area S2	53,200	9,850	23.5	6.65	2.39	0.68	2.1
Area S3	60,500	8,000	26.7	7.56	3.34	0.95	2.9
P. C. U. # 31	20,000	1,860	5.95	1.29	3.20	0.69	2.1
Pembina Sub-total	**384,080**	**60,100**	**214**	**54.2**	**3.56**	**0.90**	**2.73**
Caroline Cardium E, WF	4,400	260	2.97	0.90	12.0	3.41	10.3
Caroline Cardium E, SF	4,700	140	3.175	0.96	24.1	6.81	20.6
Carrot Creek Cardium F	5,286	1,400	1.06	0.30	0.76	0.21	0.64
Cyn-Pem Cardium A	6,410	1,200	2.59	0.73	2.16	0.61	1.8
Cyn-Pem Cardium D	7,500	2,300	2.24	0.63	0.97	0.28	0,85
Ferrier Belly River Q, Cardium G & L	73,840	9,250	69.9	14.2	11.65	2.36	7.2
Cardium Analogues Sub-Total	**102,136**	**11,300**	**82.4**	**17.7**	**7.25**	**1.57**	**4.76**
Total Protoypes + Analogues	**486,216**	**71,400**	**296**	**71.9**	**4.15**	**1.01**	**3.06**

[1] CO_2 purchased (and hence “net” utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.

6.0 REPORT SUMMARY

6.1 OVERVIEW

A detailed reservoir and development analysis to quantify the potential for incremental oil recovery and CO_2 capture and storage has been completed for five horizontal miscible CO_2 flood target pool types (prototypes) in Alberta. The detailed results from the five prototype pools have been extrapolated to some 35 analogue pools and areas to provide an estimate of CO_2 enhanced oil recovery potential, CO_2 requirement, and associated CO_2 storage potential for these pool types. Together, the prototype and analogue pools studied have original-oil-in-place of 2.523 billion cubic meters (15.869 billion barrels) and represent approximately 30% of Alberta's light-medium oil resource. For purposes of this study, the specific pool areas studied were high graded to include practical floodable areas most likely to have EOR applied (Table 6.2). The high graded areas had original-oil-in-place of 1.841 billion cubic meters (11.578 billion barrels). The ultimate objective of this project was to provide critical technical information and data to ADOE to accelerate the pace of CO_2 Enhanced Oil Recovery (EOR) and Carbon Capture and Storage (CCS) demonstration and field projects in Alberta.

While detailed economic assessment was not a deliverable of the project, economic indicators from the development plans were developed in sufficient detail that the Alberta Department of Energy (ADOE) could evaluate the economic and crown royalty impact of CO_2 EOR in Alberta. This data remains confidential is not included in this summary report.

ARC led the project with contributions from the Computer Modelling Group (CMG), Divestco Inc. (Divestco), Silvertip Ventures (Silvertip), SNC-Lavalin Inc. (SNC-Lavalin or SLI), Sproule Associates Limited (Sproule), and Vikor Energy Inc. (Vikor). The experience gained through this project has enhanced team member knowledge about CO_2 geological storage capacity in Alberta.

The target pool types were selected for study in consultation with ADOE and Alberta Energy Research Institute (AERI). They were: Beaverhill Lake waterflooded pools, Beaverhill Lake hydrocarbon miscible flooded pools, Pembina Cardium pools with thief zone, Pembina Cardium pools without thief zone, and Redwater D-3.

Specific prototype pools selected for detailed study included: waterflooded regions of Judy Creek BHL A and Swan Hills BHL A&B ; hydrocarbon solvent flooded regions of Swan Hills BHL A&B; North Pembina Cardium Unit (thief zone prototype); Pembina "A" Lease (no thief zone prototype); and Redwater D-3 (prototype for D-2 and D-3 pools).

The development plan results for the prototype pools are in Table 6.1. It was assumed that CO_2 was delivered at the field gate at the pressure required. No cost for delivered CO_2 was determined or assessed.

From the development plans, CO_2 EOR potential of the prototype pools is 45.7 million cubic meter (287.3 million barrel). Purchased CO_2 requirement is projected to be 64.6 million tonne for an average net utilization of 1.41 t/m^3 (4.27 mcf/bbl). Individual pool results vary based on amount of CO_2 injected and EOR recovery factor (Table 6.1).

Table 6.1: CO_2 EOR Prototypes-Development Plan Summary

		Cardium	Cardium	BHL	BHL	D-3	Total
		TZ	NTZ	WFA	SFA	Redwater	
OOIP	**e^6m^3**	66.9	59.7	43.5	149.4	226.7	546.3
Oil Recovery	**e^6m^3**	11.2	7.7	9.5	4.5	12.8	45.7
Oil Recovery	**10^6 Bbl**	70.5	48.3	59.7	28.5	80.4	287.3
		16.7%	12.8%	21.8%	3.0%	5.6%	8.4%
HCMS Recovery	**e^6m^3**				1,231		
CO_2 Injection	**Mt**	36.9	68.5	39.9	45.2	62.0	252.5
% HCPV		50.3%	99.1%	79.3%	40.5%	100.1%	
CO_2 Purchased	**Mt**	10.4	13.9	12.5	10.3	17.5	64.6
		14.2%	20.1%	24.8%	9.3%	28.2%	
Gross Utilization	**t/m^3**	3.29	8.93	4.21	9.96	4.85	
Net Utilization	**t/m^3**	0.93	1.81	1.31	2.28	1.37	
Gross Utilization	**mcf/Bbl**	9.97	27.07	12.76	30.20	14.72	
Net Utilization	**mcf/Bbl**	2.82	5.50	3.98	6.91	4.15	

Combined data for prototypes and analogue pools are presented in Table 6.2. Detailed development plans were not prepared for the analogues. Data has been extrapolated from prototype performance as described in the methodology section below. Thus, there is a lower accuracy in the estimates and F&D costs are not stated, since they have not been determined for the analogues. The total potential CO_2 EOR for the prototypes and analogues studied is projected to be 171.4 million m^3 (1.08 billion bbl); this would require purchase of 253 million tonne of CO_2, essentially all of which would be retained in the pools. .

6.2 METHODOLOGY

Prototype pools were selected from among the pools listed in Table 1 of the RFP in consultation with ADOE and operators based on perceived opportunity and availability of data from operators. For each prototype field a small (approximately 0.4 ha [1 section]) “sector” was selected for geological and numerical modelling. For each sector, Divestco built a geological model in Earthvision software.

Table 6.2: CO_2 EOR Requirement and Storage for Prototypes and Analogues – No Risk Factor							
Prototypes and Analogues	**OOIP**	**Predicted CO_2 Oil Recovery**	**CO_2 Injected**	**CO_2 Purchased**	**CO_2 Utilization**		
	10^3m^3	**10^3m^3**	**10^6t**	**10^6t**	**Gross (t/m^3)**	**Net (t/m^3)**	**Net (mcf/bbl)**
BHL Prototypes and Analogues (WFA & SFA)	752,608	55,605	360	99.2	6.48	1.78	5.4
D-2/D-3 Prototype and Analogues	601,853	44,360	277	82.0	6.24	1.85	5.6
Cardium Prototypes and Analogues (Thief zone and non-thief zone)	486,216	71,400	296	71.9	4.15	1.01	3.1
Total	1,840,677	171,365	933	253	5.44	1.48	4.5

The sector geological model was imported into a numerical simulator to create a comparable numerical model for simulation. The production history and well completion history (obtained from the ERCB data base and/or operator) for the sector were history matched using CMG simulation software (except the “Pembina without thief zone” prototype which used Eclipse simulation software). Once an acceptable history match was obtained, forecasts of various scenarios were carried out with the numerical model. Numerical modelling was carried out by Computer Modelling Group (BHL Solvent flood and Pembina with Thief Zone prototypes) and Alberta Research Council (BHL Waterflood, Pembina without Thief Zone, and Redwater prototypes).

First, a “do-nothing baseline” waterflood was continued using only those wells still in operation at the end of the history match to provide a “baseline” waterflood recovery. Then, CO_2 flood forecasts were carried out for various scenarios using different water-alternating-gas ratios, varying hydrocarbon pore volume injected, and well patterns. Sector model results were extrapolated to the full prototype by creating “area” models with adjusted geological parameters to reflect the reservoir variability across the full prototype and then rerunning forecast scenarios with the adjusted models.

Area model performance and fractional flow curves derived from the area model simulation were used as input for preparation of a “development plan” for each prototype. Development plans were prepared by Vilkor Energy Inc. using Vikor’s “Pattern Development Model” (Appendix 1). Using existing wells and new wells where required, well patterns were prepared for each prototype pool to fully develop a CO_2 flood in the prototype pool. The Pattern Development Model is used to assess development scenarios by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns. Well cost factors for well drilling, completion and conversion for the prototype pools were developed by Silvertip Ventures. Unit cost factors for gas processing have been derived from capital and operating cost estimates prepared by SNC Lavalin (SNC). SNC has reported two cases: a full produced gas recycle case with no separation of CO_2 from other produced gases and a recycle case in which CO_2 is separated from produced gases prior to reinjection. For the Swan Hills waterflood area, Pembina, and Redwater development plans, the full recycle scenario was used. For the Swan Hills hydrocarbon solvent flood area development plan, the CO_2 separation scenario was used. Pengrowth, the Judy Creek Gas Conservation System operator, provided input into the estimates. The SNC report is provided as Appendix 3.

The cost factors have been utilized in the development plans to estimate capital expenditures to implement the development scenarios. No capital cost was included in the waterflood case. No additional contingency was added to the SNC and Silvertip estimates. Assumptions used in developing the cost factors are provided in the respective Sections. Vikor developed the field and plant operating costs, other than recycle operating costs. Estimated capital and operating costs have not been included in this summary report.

6.3 DEVELOPMENT PLANS

Swan Hills Waterflood Development Plan

The EOR project was developed using, where possible, inverted 5 spot patterns on 32 ha (80 acre) per well spacing and required 10 existing injection wells and 30 converted production wells for injection into all layers. The inverted 5 spot patterns on 32 ha (80 acre) per well spacing are consistent with recent development; experimentation with further infill to 16 ha (40 acre) per well spacing is ongoing. Twenty-two new wells and 54 existing production wells were used for production. It was assumed that less productive layers in all wells would be stimulated to enhance processing rate when most productive layers are shut in. The forecast assumed all wells stay on production for the life of the patterns that they service at rates as determined from analysis of historical well performance in each area.

The development plan forecasts recovery of almost 9.5 million m^3 of EOR incremental oil by injection of almost 40 million tonnes of CO_2, including 12.5 million tonnes purchased plus recycle.

The most significant technical risks for BHL waterflood targets include:

- Prior waterflood and solvent flood operations have likely displaced oil in the reef making oil saturation when the CO_2 EOR is initiated difficult to predict. The wide variation in oil recovery in Table 5.2.3.1 may be a result of this.
- Simulation predictions are very complex and many simplifying assumptions must be made. In this case, performance of all of the areas was not history matched, consequently prediction is less reliable.
- The operation would need to be integrated with the larger solvent flood area that borders much of the waterflood area.

Swan Hills Solvent Flooded Region Development Plan

The area of the reef build-up in the Swan Hills Beaverhill Lake A&B Pool that previously had hydrocarbon miscible solvent flood injection was chosen as the prototype for CO_2 EOR in Solvent Flood Areas (SFA) of Beaverhill Lake Pools. The development area consisted of 100 inverted 5 spot patterns on 32 ha (80 acre) per well spacing. The spacing is consistent with recent Swan Hills development.

CO_2 EOR incremental oil recovery of over 4.5 million m^3 or 3.0% OOIP is forecast by the simulation with the injection of over 45 million tonnes of CO_2 (10.3 million tonnes purchased) 40% HCPV of CO_2 at a WAG of 1:1 followed by chase water in four of the five areas. Source CO_2 is required for 22 years, 9 years at maximum rate of 2,000 tonne per day.

The most significant technical risks include:

- Prior miscible solvent flood operations have produced a significant portion of the miscible oil in the reef making oil saturation when the CO_2 EOR is initiated difficult to predict. This is a quaternary flood rather than tertiary, the first in the world.
- Simulation predictions are very complex and many simplifying assumptions must be made. The difficulties completing the runs and inability to meet expected WOR and the much lower total oil recovery in the simulator compared to the field is of concern. Performance of all of the areas was not history matched, consequently prediction is less reliable.
- The operation would need to be integrated with the lower quality waterflood area that borders much of the solvent flood area.

Pembina with Thief Zone Development

The EOR project development plan for Pembina with Thief Zone used existing vertical wells on 32 ha (80 acre) per well spacing for injection into all zones and the existing vertical production wells completed in all zones plus new 600 m horizontal wells competed only in sand 4. The concept was that the area is productivity limited with restricted communication between sand 4 and the upper sand 5/6 and conglomerate. By injecting into all zones and limiting production from the sand 5/6 and conglomerate, pressure should be higher in the upper zone promoting injection into the higher oil saturation sand 4. In addition new horizontal water injection wells were drilled at the end of the on-trend patterns to try to create a pressure "fence" to minimize loss of CO_2 from the patterns through natural fractures.

The development plan shows that the NPCU enhanced recovery by CO_2 will recover significant incremental oil with the given assumptions. Important features of the development plan results are:

- CO_2 incremental oil for the development area is 16.7% of original-oil-in-place. This is approximately 11.2 million m^3 (70.5 million barrels) incremental recovery from the 66.9 million m^3 (421 million barrels) of original-oil-in-place in the development area.
- In 75 years 5.6 million m^3 of waterflood oil is also produced; without the development 4.8 million m^3 of Base Case waterflood oil would be produced in 75 years.
- Gross CO_2 utilization factor was 3.29 tonne/m^3 (10.0 mcf/bbl) of incremental oil; net utilization factor was 0.93 tonne/m^3 (2.82 mcf/bbl)
- Source CO_2 is required for 32 years, 13 years at maximum rate of 1,200 tonne per day.
- Total CO_2 injection was 36.9 million tonnes, of which 10.4 million tonnes was purchased.If all produced CO_2 were injected 10.4 million tonnes would be stored. Considering that this is the best area of Pembina, this is not a large amount of stored CO_2.

A number of risk factors exist:

- In the numerical simulation of NPCU, production from the top conglomerate zone was controlled in order to achieve better sweep and recovery from the lower zones (which contain the bulk of the OOIP). The ability to control the flow of CO_2 into the conglomerate is uncertain and introduces risk that the field may not perform as predicted by the simulation and development plan. In addition, the integrity of the shale and impacts of the vertical fractured wells are unknowns. These factors may be mitigated by improvements in horizontal well drilling and fracturing technology in the years preceding the start of the CO_2 flood. At this stage the highest probability that could be assigned is an 80% chance of success with this approach. The ARC Resources CO_2 pilot may help to assess this risk.
- Can the productivity of the horizontal wells running in the off trend direction be achieved and sustained and fracturing into the upper zones be prevented. Once significant volumes of CO_2 are produced, well bottom hole producing pressure must be kept high to minimize Joule-Thompson cooling further impacting productivity.
- Processing rate for injection/production in much of the Pembina area is low. The risk is that there may not be enough productivity and injectivity in any but the best area of Pembina to complete the project in a reasonable time. The numerical simulation required significant time to inject the required volumes of CO_2 that can significantly impact project economics.
- Can we flood off trend from the line drives and contain the CO_2 in the pattern with the fence wells.
- Field piloting, testing of long horizontal wells in Sand 4 and successfully stimulating with multiple fractures, and staging of the project can help reduce technical risks.

Pembina without Thief Zone Development

The EOR project was developed as a line drive with vertical injection wells on 16 ha (40 acre) per well spacing for injection into all zones and new 1,200 m horizontal wells between the injectors, completed in the middle of sand 4 with fractures to the other layers. The area is very productivity limited and required infill drilling to tight , 20 acre spacing per well. In addition new horizontal water injection wells were drilled at the end of the on-trend patterns to try to create a pressure "fence" to minimize loss of CO_2 from the patterns through natural fractures. All of the trend patterns are developed together to use the fence wells before adjacent off trend patterns are developed.

The EOR recovery project benefits from two factors, a very significant acceleration of oil production and good incremental recovery from CO_2 injection. The modelling indicated that almost 1,000 years of operation would be required to reach the economic limit with current wells, only 8.4% HCPV of water was injected in 75 years in the Base Case waterflood. A very large amount of capital is involved in developing the area to achieve an acceptable processing rate; the development plan was not optimized.

The parts of the “A” Lease and the better portion of the Cyn Pem Unit #3 analyzed are the best parts of these areas in the Pembina Cardium. CO_2 EOR incremental oil recovery of 7.7 million m^3 or 12.8% OOIP is forecast by the simulation with the injection of 68.5 million tonnes of CO_2 (13.9 million tonnes purchased), 99.1% HCPV of CO_2 at a WAG of 1:1 followed by chase water. All of the patterns had finished chase water injected in the 65 year forecast. In 65 years, 13.9 million m^3 of waterflood oil is also produced, without the development only 5 million m^3 of Base Case waterflood oil would be produced in 75 years. Source CO_2 is required for 29 years, 22 years at maximum rate of 1,500 tonne per day. If all produced CO_2 were injected, then 13.9 million tonnes would be stored. Net CO_2 utilization is 1.8 tonne/m^3 (5.5 mcf/Bbl); gross CO_2 utilization is poor at 8.9 tonne/m^3 (27 mcf/Bbl), based only on the CO_2 EOR oil.

The most significant technical risks include:

- The impact of the natural fractures on containing the flood in the patterns and zones is a very large geological risk. Will the flood move off trend from the line drive and the fence wells contain the CO_2 in the pattern?
- Can the productivity of the horizontal wells running in the off trend direction be achieved and sustained?
- Can the flow be forced to the off trend wells with good vertical conformance?
- Is the acceleration of the remaining reserves and the CO_2 EOR potential sufficient to support the capital expenditure required?
- Will the productivity and injectivity be adequate to complete the project in a reasonable length of time?
- Operating pressure is very high so cap rock and well bore integrity is critical. Also the high pressure will complicate well operation and workovers.
- Can wax deposition in the reservoir near production wells caused by cooling from the expansion of CO_2 be avoided?

An extended field pilot test will be necessary to develop strategies to mitigate these risks.

Redwater Development

The Redwater EOR project was developed with 222 inverted 9 spot patterns using existing vertical wells on 16 ha (40 acre) per well spacing. The forecast assumes all wells stay on production for the life of the patterns that they service at rates provided from analysis of historical well performance in each area. that The development plan assumed that the displacement process is horizontal, not vertical as assumed in previous EOR predictions in the pool. ARC Resources believes the displacement process is vertical, which is preferable if vertical continuity is sufficient for the process to work. Recovery from the pool is excellent to date, in part because of very efficient fluid handling. CO_2 EOR will have to be operated very efficiently to be economic as large volumes of fluid must be processed. Incremental recovery is relatively low because the process is not fully miscible and the remaining target is low.

CO_2 EOR incremental oil recovery of 12.8 million m^3 or 5.6% OOIP is forecast by the simulation. Sixty-two million tonnes of CO_2 (17.5 million tonnes purchased), equivalent to 100.1% HCPV of CO_2, were injected at a WAG of 1.1 followed by up to 275% HCPV of chase water. Because of the high processing rate and tight well spacing the injection could be completed in about 30 years. Source CO_2 is required for

14 years, 11 years at maximum rate of 4,000 tonne per day. If all produced CO_2 were injected, then 17.5 million tonnes would be stored. Net CO_2 utilization is good at 1.37 tonne/m^3 (4.1 mcf/Bbl); gross CO_2 utilization is 4.85 tonne/m^3 (14.7 mcf/Bbl), based on EOR oil.

The most significant technical risks include:

- The flood must be operated at near miscible conditions to achieve predicted recovery. Reaching this pressure may be difficult with the underlying aquifer that is connected with the massive Cooking Lake aquifer.
- The operating pressure and temperature are very close to CO_2 critical point complicating the performance prediction.
- Whether the CO_2 flood can be operated as a vertical or horizontal displacement process is uncertain. The geological analysis used in this study suggests that barriers preclude a vertical displacement process. The operator does not believe these barriers are continuous and is piloting to see if vertical displacement can be achieved. The horizontal displacement process evaluated in this study should be more conservative than a vertical displacement process.
- Gravity override will very negatively impact a horizontal displacement process in the thick zones as the CO_2 is much lighter than oil (250 kg/m^3) at operating conditions.
- If reservoir pressure could be increased to hydrostatic level, CO_2 density could be increased to about 700 kg/m^3 reducing gravity override and increasing CO_2 storage, but utilization factor would be much poorer.
- The pool has many old wells, is relatively shallow and is proximate to areas with significant population and hence safety precautions will be critical.

A field pilot test will be necessary to confirm that the CO_2 will mobilize sufficient residual oil at achievable operating conditions.

6.4 ANALOGUES

A number of "analogue" pools to the prototype pools were identified. The results of sector model simulation and prototype development plans were used to extrapolate results to the analogue pools. A methodology was developed to extrapolate simulation and development plan results to estimate CO_2 enhanced oil recovery potential and CO_2 requirements and utilization for the analogue pools.

Table 6.3 gives EOR oil recovery and CO_2 requirements for the Beaverhill Lake group of pools. For the BHL target pools, potential CO_2 EOR would be 55.6 million m^3 (350 million bbl). Total injection of CO_2 including recycle would be 360.2 Mt. giving a gross CO_2 utilization of 6.48 t/m^3 (19.6 mcf/bbl). A total of 99.2 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.78 t/m^3 (5.39 mcf/bbl). Essentially all of the purchased CO_2 would be retained (stored) in the BHL pools at the end of the project life.

Table 6.3: CO_2 Requirement and Storage for BHL Prototypes and Analogues-No Risk Factor

Field/Pool	Recovery Process	OOIP	Predicted EOR Oil Recovery	CO_2 Injected	CO_2 Purchased[1]	CO_2 Utilization		
		10^3m^3	10^3m^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
Ante Creek BHL	SF	5931	580	2.47	0.57	4.25	0.97	2.9
Carson Creek North BHL A & B	WF	56930	9700	54.2	16.9	5.59	1.74	5.3
Goose River BHL A	SF	16160	530	6.11	1.40	11.53	2.64	8.0
Goose River BHL A	WF	9341	1090	6.72	2.10	6.16	1.92	5.8
Judy Creek BHL A	SF	77950	3520	26.7	6.11	7.58	1.74	5.2
Judy Creek BHL A	WF	48030	2900	24.25	7.56	8.36	2.61	7.9
Judy Creek BHL B	SF	28370	1210	11.13	2.55	9.20	2.11	6.4
Judy Creek BHL B	WF	11360	1320	7.67	2.39	5.81	1.81	5.5
Kaybob BHL A	SF	36830	940	17.43	3.99	18.54	4.24	12.8
Kaybob BHL A	WF	11290	1310	10.0	3.13	7.66	2.39	7.2
Simonette BHL A	WF	7764	1330	14.2	4.44	10.69	3.34	10.1
Snipe Lake BHL	WF	36600	3450	18.5	5.78	5.37	1.67	5.1
Swan Hills BHL A & B (SF prototype)	SF	149435	4539	45.2	10.3	9.96	2.28	6.9
Swan Hills BHL A & B (WF prototype)	WF	43547	9486	39.9	12.5	4.21	1.31	4.0
Swan Hills South BHL A & B	SF	138800	6800	38.5	8.81	5.66	1.30	3.9
Virginia Hills BHL	SF	35340	3400	10.87	2.49	3.20	0.73	2.2
Virginia Hills BHL	WF	38930	3500	26.24	8.19	7.49	2.33	7.1
Sub-total for WF group	**WF**	**263,792**	**34,086**	**201.8**	**63.0**	**5.92**	**1.85**	**5.6**
Sub-total for SF group	**SF**	**488,816**	**21,519**	**158.4**	**36.2**	**7.36**	**1.68**	**5.1**
Total		**752,608**	**55,605**	**360.2**	**99.2**	**6.48**	**1.78**	**5.4**

[1] CO_2 purchased (and hence "net" utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.

Table 6.4 gives EOR oil recovery and CO_2 requirements for the D-2 and D-3 group of pools. For the D-2/D-3 target pools, potential CO_2 EOR would be 44.4 million m^3 (279 million bbl). Total injection of CO_2 including recycle would be 277 Mt giving a gross CO_2 utilization of 6.24 t/ m^3 (18.9 mcf/bbl). A total of 82 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.85 t/m^3 (5.60 mcf/bbl). Essentially all of the purchased CO_2 would be retained (stored) in the D-2/D-3 pools at the end of the project life.

Table 6.5 gives the EOR oil recovery and CO_2 requirements for the group of Cardium pools and areas studied. The Pembina Cardium field contributes the bulk of the CO_2 EOR for the Cardium group. For Pembina Cardium, potential CO_2 EOR would be 60.1 million m^3 (378 million bbl). Injection of CO_2 including recycle would be 214 Mt giving a gross CO_2 utilization of 3.56 t/m^3 (10.8 mcf/bbl). A total of 54.2 Mt of purchased CO_2 would be required giving net CO_2 utilization of 0.90 t/m^3 (2.73 mcf/bbl). Essentially all of the purchased CO_2 would be retained (stored) in the Pembina Cardium at the end of the project life.

Table 6.4: CO_2 Requirement and Storage for D-2/D-3 Prototype and Analogues-No Risk Factor							
Field/Pool	**OOIP**	**Predicted EOR Oil Recovery**	**CO_2 Injected**	**CO_2 Purchased[1]**	**CO_2 Utilization**		
	10^3m^3	**10^3**	**10^6t**	**10^6t**	**Gross (t/m^3)**	**Net (t/m^3)**	**Net (mcf/bbl)**
Fenn Big Valley D-2A	74200	2700	46.2	13.4	17.1	4.97	15.0
Joffre D-2	26650	2900	11.8	3.69	4.08	1.27	3.8
Leduc Woodbend D-2A	32700	5.07	12.2	3.80	2.40	0.75	2.3
Meekwap D-2A	11810	390	9.26	2.69	23.7	6.91	20.9
West Drumheller D2A & B	8905	1780	3.74	1.17	2.10	0.66	2.0
Bonnie Glen D-3A	125000	4770	56.1	16.3	11.7	3.42	10.4
Leduc Woodbend D-3A	52650	2280	32.6	9.50	14.3	4.17	12.6
Morinville D-3B	3318	104	1.71	0.50	17.1	4.97	15.0
Redwater D-3	207000	12778	60.0	17.5	4.85	1.37	4.2
Sturgeon Lake D-3A	13550	1720	9.81	3.06	5.70	1.78	5.4
Sturgeon Lake South D-3	46070	9870	33.3	10.4	3.38	1.05	3.2
Total	**601,853**	**44,360**	**276.7**	**82.0**	**6.24**	**1.85**	**5.6**

[1] CO_2 purchased (and hence "net" utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.

For the combined Pembina Cardium and Cardium analogues assessed, the total potential CO_2 EOR would be 71.4 million m^3 (449 million bbl). Injection of CO_2 including recycle would be 296 Mt giving a gross CO_2 utilization of 4.15 t/m^3 (12.6 mcf/bbl). A total of 71.9 Mt of purchased CO_2 would be required giving net CO_2 utilization of 1.01 t/m^3 (3.06 mcf/bbl). Essentially all of the purchased CO_2 would be retained (stored) in the Cardium protoypes and analogues at the end of the project life.

Table 6.5: CO_2 Requirement and Storage for Pembina Prototypes and Analogues-No Risk Factor

Field/Pool	OOIP	Predicted EOR Oil Recovery	CO_2 Injected	CO_2 Purchased[1]	CO_2 Utilization		
	10^3m^3	10^3m^3	10^6t	10^6t	Gross (t/m^3)	Net (t/m^3)	Net (mcf/bbl)
NPCU & PCU 20 (Pembina with TZ prototype)	66,900	11,209	36.9	10.4	3.29	0.93	2.8
A Lease & Cynthia Unit 3 (Pembina no TZ prototype)	59,700	7,673	68.5	13.9	8.93	1.81	5.5
Pembina Bear Lake	5,710	1,800	2.52	0.71	1.40	0.40	1.2
Pembina Berrymoor	35,400	6,530	15.7	4.43	2.40	0.68	2.1
Pembina Cynthia Unit 2	6,880	1,230	6.08	1.24	4.95	1.00	3.0
Pembina Lobstick	37,900	7,080	11.3	3.21	1.60	0.45	1.4
Pembina Cardium South (Units 2 & 3)							
Area S1	37,900	4,900	16.8	4.74	3.42	0.97	2.9
Area S2	53,200	9,850	23.5	6.65	2.39	0.68	2.1
Area S3	60,500	8,000	26.7	7.56	3.34	0.95	2.9
P. C. U. # 31	20,000	1,860	5.95	1.29	3.20	0.69	2.1
Pembina Sub-total	**384,080**	**60,100**	**214**	**54.2**	**3.56**	**0.90**	**2.73**
Caroline Cardium E, WF	4,400	260	2.97	0.90	12.0	3.41	10.3
Caroline Cardium E, SF	4,700	140	3.175	0.96	24.1	6.81	20.6
Carrot Creek Cardium F	5,286	1,400	1.06	0.30	0.76	0.21	0.64
Cyn-Pem Cardium A	6,410	1,200	2.59	0.73	2.16	0.61	1.8
Cyn-Pem Cardium D	7,500	2,300	2.24	0.63	0.97	0.28	0,85
Ferrier Belly River Q, Cardium G & L	73,840	9,250	69.9	14.2	11.65	2.36	7.2
Cardium Analogues Sub-Total	**102,136**	**11,300**	**82.4**	**17.7**	**7.25**	**1.57**	**4.76**
Total Protoyes + Analogues	**486,216**	**71,400**	**296**	**71.9**	**4.15**	**1.01**	**3.06**

[1] CO_2 purchased (and hence "net" utilization, the ratio of purchased CO_2 to EOR oil produced) was directly determined only for prototypes in the development plans. For the analogues, the ratio of purchased to injected CO_2 of the respective prototypes was used to estimate the CO_2 purchase requirement.

6.5 RECOMMENDATIONS

ARC recommends further work in the following areas:

- A total of 17 different prototypes were recommended to cover the formations suitable for horizontal miscible, horizontal immiscible and floods on pools with a gas cap. To commence the project 5 prototypes were selected in the largest horizontal miscible pools. Additional work on the 12 other prototypes and on the vertical displacement pools, not included in the original RFP would enhance the understanding of potential CO_2 recovery in Alberta.
- The five simulations produced in this report require more refinement. Specifically more sensitivities are required. Time and resources available in the current project were not sufficient to conduct a broad suite of sensitivities. Area models could be improved by more realistic history matching.
- The simulations have been run on the prototypes with the most potential for CO_2 EOR in the province. History matches and sensitivity studies to select injection strategy for these simulations were performed on relatively small areas of the pools. Predictive only runs were made for other pool areas with adjusted pay, porosity, permeability and saturation, without any history match or analysis of optimum injection strategy. Accuracy could be improved by completing history matches and injection strategy sensitivities on all of the areas. In particular further work on the Beaverhill Lake Solvent Flood Areas would be beneficial because of the size of the prize and the difficulty achieving satisfactory prediction runs.
- Locating CO_2 backbone pipeline in relation to the best CO_2 storage reservoirs.
- This study was restricted to the field characteristics for CO_2 flooding and did not consider the proximity to suitable CO_2 sources and the cost to deliver CO_2 to the field. It would be useful to build on this work by evaluating potential sources and estimate transportation costs to deliver the CO_2 to the fields so economics can be run to quantify the size of the “gap” between the cost to capture, purify, compress and transport the CO_2 and its value as a solvent.

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Appendix 1

Pattern Development Model
Vikor Energy Inc.

The Pattern Development Model is used to assess development scenarios by starting new patterns to fully utilize available purchased and produced CO_2 within the limits of injectivity and productivity of the operating patterns.

Input Data:

OOIP is calculated for each pattern. The maximum allowed injection and production rate in reservoir m^3 per day is specified for each well. In order to improve oil production response CO_2 may be injected at a higher ratio to water initially (lower WAG). The WAG ratio utilized and the HCPV injected are shown in the description of each run.

Production wells are assigned to the appropriate patterns in a matrix with the injection wells. Production wells common to several patterns have their production allocated to each operating pattern.

CO_2 Source:

Available purchased CO_2 volume is specified and can be varied over project life. To control the pace of development of the pool the CO_2 source volume should be selected to provide about 10 years of source CO_2 injection at a flat rate. Once the last patterns are developed the program reduces the required CO_2 source rate to match the maximum required injection of CO_2. The model always preferentially recycles produced CO_2.

Pattern Layout:

Patterns can be selected to use existing waterflood patterns with water injection wells converted to WAG injectors. New infill wells can be drilled or producing wells converted to injectors and injection wells converted to producers. The OOIP is required for each pattern. The pattern layout must be consistent with the performance prediction, i. e. separate prediction of the performance for a 9 spot and 5-spot is needed.

Injection/Production Determination:

Production and injection rate is an important parameter in enhanced oil recovery economics. A reasonable estimate of the maximum productivity and injectivity for each well in the pool is required to develop the production schedule.

Fractional Flow Curves:

The fractional flow curve is the percentage of oil, hydrocarbon solvent, CO_2 and water at reservoir conditions being produced at any point in time. The oil, hydrocarbon solvent (if applicable) and CO_2 are determined for each time step, by default water fraction is the remainder so the sum equals one.

The fractional flow curves used to predict the oil and solvent recovery from CO_2 EOR are for the incremental oil (solvent) to the EOR development only. Simultataneously with the production from the EOR developed area the oil (solvent) recovery from the Base Case waterflood from the total pool is calculated and added to the EOR oil (solvent) in the EOR developed area and separately for the remainder of the pool. This data is reported on the output table in columns headed “in CO_2 EOR” and “Base Case (Existing W/F or HCMS Patterns not on CO_2 flood)”. The “T” factor can be calculated by dividing the CO_2 EOR oil minus the oil “in CO_2 EOR” divided by CO_2 EOR plus “Base Case (Existing W/F or HCMS Patterns not on CO_2 flood)”.

Fractional flow curves are used to predict the produced oil and CO_2 flow as a fraction of total production and as a function of the percentage hydrocarbon pore volume of total CO_2 plus water injection. Different fractional flow curves are used to run sensitivities for different development strategies, WAG ratios or reservoir assumptions. Different fractional flow curves can be assigned to patterns to account for changes in the reservoir properties.

A separate set of fractional flow curves are needed for each different pattern response expected for each Case. For example a Case might be to inject 100% CO_2 for 10% HCPV, followed by a WAG ratio of 0.5 for 20% (CO_2) HCPV, followed by a WAG ratio of 2.0 for 20% (CO_2) HCPV, then followed by 100% water for 50% HCPV, for a total injection of 150% HCPV, 50% HCPV CO_2. A set of fractional flow curves, preferrably in 1% HCPV increments showing the share of flow (in reservoir volume) of oil, CO_2 and, if applicable, hydrocarbon miscible solvent, remainder is assumed to be water, for each area that has different performance. See attached example fractional flow table.

To account for some risk a percentage of predicted oil and CO_2 production can be used in the economic runs.

Prediction Method:

A sufficient number of patterns for the specified injection rate begin to operate at the start of the project. The program injects the available purchased CO_2 and the volume of CO_2 produced in the previous time step, at the specified WAG ratio and the percentage of hydrocarbon pore volume injected at the end of the specified time is determined. The fractional flow curve for this percentage of hydrocarbon pore volume is then used to predict the volume of oil and CO_2 produced. The status of injection for each pattern is tracked independently for each time step.

The maximum injection rate is determined by the pattern injectivity and productivity, assuming a voidage replacement ratio of one. The available productivity is calculated from the productivity of the specified wells producing from the pattern. The producing well productivity is divided equally among the number of operating patterns from which the well produces. Pattern productivity will change as new patterns are added. Some of the wells which initially only produce from one pattern could ultimately, in a five spot development, produce from four patterns.

A new pattern is added when the existing patterns are unable to take the available CO_2. Once all of the patterns are operating the source CO_2 purchases are limited to match the demand assuming 100% of the produced CO_2 is recycled. CO_2 injection terminates into a pattern when the specified % HCPV of CO_2 is reached and the pattern remains in operation, including any producing wells associated with it, until the total CO_2 and water injection volume is reached.

Output:

The program tracks the number of patterns and wells operating at any given time. The new injection and production wells required with a new pattern is determined and the specified well completion and tie-in cost added when the pattern comes on stream.

The production well starts up when the first pattern it is associated with begins injection and is shut in when the last pattern it is associated with ceases injection. The number of operating injection and production wells is tracked in order to estimate well operating costs. The oil, water, and CO_2 production and the volume of source and recycled CO_2 and water injected are calculated monthly.

Appendix 2

Conceptual Surface Facilities Design For CO_2 Flood

SCN Lavalin

SNC·LAVALIN

FINAL REPORT
Revision 1

ENHANCED HYDROCARBON RECOVERY STUDY

Prepared for

Alberta Research Council Inc. (ARC)

Project #017935

September, 2008

SNC·LAVALIN

TABLE OF CONTENTS

NOTICE TO READER

This document contains the expression of the professional opinion of SNC-Lavalin Inc. ("SLI") as to the matters set out herein, using its professional judgment and reasonable care. It is to be read in the context of the agreement dated November 12, 2007 (the "Agreement") between SLI and Alberta Research Council Inc. (the "Client" or "ARC"), and the methodology, procedures and techniques used, SLI's assumptions, and the circumstances and constraints under which its mandate was performed. This document is written solely for the purpose stated in the Agreement, and for the sole and exclusive benefit of the Client, whose remedies are limited to those set out in the Agreement. This document is meant to be read as a whole, and sections or parts thereof should thus not be read or relied upon out of context.

SLI has, in preparing the cost estimates, followed methodology and procedures, and exercised due care consistent with the intended level of accuracy, using its professional judgment and reasonable care, and is thus of the opinion that there is a high probability that actual costs will fall within the specified error margin. However, no warranty should be implied as to the accuracy of estimates. Unless expressly stated otherwise, assumptions, data and information supplied by, or gathered from other sources (including the Client, other consultants, testing laboratories and equipment suppliers, etc.) upon which SLI's opinion as set out herein is based has not been verified by SLI; SLI makes no representation as to its accuracy and disclaims all liability with respect thereto.

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1.0 EXECUTIVE SUMMARY

This study forms part of one component, Task 3, of a wider project being undertaken by ARC for the Alberta Energy Research Institute ("AERI") titled "CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta". SNC Lavalin's scope of work is to evaluate two cases of the surface facility design in a conceptual commercial scale operation, for the selected oil field (subsequently defined as a "hypothetical" field). We are told that the purpose of developing this processing design and cost estimate is to provide a basis for extrapolating the processing from one hypothetical Alberta oil producing field to any number of real Alberta oil fields once the preliminary reservoir evaluation work has been completed and ranked (a task being done by others in parallel with this work).

Two cases were considered to process the production from the hypothetical oilfield:

Case 1: Separation of fluids and compression of the produced gas back into the reservoir without any CO_2 /hydrocarbon separation.

Case 2: Separation of fluids, recovery and purification of CO_2 and compression of the produced CO_2 for re-injection into the reservoir at a purity of some 96% v/v CO_2.

The design concept for the CO_2 processing facility excludes any gathering or distribution pipelines. The facility is assumed to be installed as a new separate unit at the inlet of an existing oil production and treating facility in Alberta. It is assumed that the new facility will require electric power from the grid and that all other utility requirements (relatively minor, including natural gas) will be available from the host oil production facility. It is also assumed that the oil production facility will have associated with it an adequately sized gas processing unit. Given the large inlet flowrate variations during the project lifetime, the facilities were sized based on operating year 19 flow rates, considered to be the peak production year of the project.

Note that all dollar values in this report are expressed in CAD. SLI has used an exchange rate from USD, the currency of most of the external information sources, at a nominal exchange rate of CAD 1.00 = USD 1.00.

Capital and operating costs of the selected membrane technology are summarized as follows:

Table 1.0-1
Selected Membrane Technology - Capital and Operating Costs Summary

CO_2 Re-injection Strategy	Case 1 Mixed Re-injection (No CO_2 separation)	Case 2 CO_2 Re-injection (With CO_2 separation)
Raw Stream CO_2 Conc. Vol %	88	88
Re-Injected Stream CO_2 Conc. Vol % (1)	89	96
Separated CO_2 Volume Tonnes per stream Day (1)(2)	5280	4900
Separated CO_2 Volume Tonnes per Calendar Year (1)(2)	1,830,000	1,700,000
Capital Cost CAD MM (1st quarter 2008)	141	292
Operating Costs CAD MM/yr (3)	4.43 - 12.23	6.8 - 24.08
Unit value of CO_2 that generates a project real NPV_8 of zero (4)	$19.65	$23.68
Total CO_2 reinjected over 40-year Project life; million tonnes	39.13	36.32

Notes:
(1) Actual amounts vary from year to year
(2) Numbers are rounded
(3) Range over project life
(4) Case 2 includes income from sales of C1, C2, C3+ at market price less processing costs.

In our opinion, the results indicate:

1. CO_2 recovered from produced gas at a CO_2-EOR project that has the parameters used here will likely be a less expensive source of CO_2 than fresh CO_2 purchased from a CO_2 supply pipeline. This is the case whether ethane and other components are extracted from the produced gas or not.
2. Separation of ethane from the produced gas is costly from a capital standpoint and does not appear to be an economic proposition on its own.

2.0 INTRODUCTION

2.1 Overall Project Scope

This study forms part of one component, Task 3, of a wider project being undertaken by the Client for the Alberta Energy Research Institute ("AERI") titled "CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta". As we understand it the other two components are:

- Task 1 identifies, based on reservoir and performance characteristics, seventeen prototype pools forming the basis for further evaluation in Tasks 2 and 3.
- Task 2 involves more rigorous evaluation of the 17 pools selected from Task 1. Of these pools, 12 are evaluated using correlations (incorporated in PRIze) and five are to be benchmarked against actual field data and available simulation predictions and to permit extrapolation of information to other Alberta pools.

Task 3 (this task) is to prepare a development plan where economic factors and policy elements can be considered and evaluated. Specifically, SNC-Lavalin's scope of work is to evaluate two cases of the surface facility design in a conceptual commercial scale operation, for the selected oil field (subsequently defined as a "hypothetical" field). ARC has further Task 3 responsibilities for downhole operational estimating and extrapolation of all results to other Alberta pool locations.

The original intent was that Tasks 1 and 2 would precede the commencement of Task 3 but due to time constraints and the desire to maintain the study completion date, it was decided that Task 3 would proceed parallel to Tasks 1 and 2, on the basis of assumed reservoir production volumes and compositions developed by Vikor Resources on behalf of AERI as "typical" of what might be produced from a mature Alberta oilfield. In this instance the example used was Judy Creek and Pengrowth were very helpful in providing typical analyses and other information about their operations in the area.

2.2 SNC-Lavalin Scope

ARC asked SNC-Lavalin Inc. ("SLI") to conduct a study to examine the technical feasibility and associated costs of recovering CO_2 from oilfield production from a "typical" Alberta oilfield EOR project and compression of the recovered CO_2 for further EOR use or delivery to a pipeline in the same area. This study report summarizes SLI's findings based on two cases evaluated:

- ***Case 1:*** Separation of fluids and compression of the produced gas back into the reservoir without any CO_2 /hydrocarbon separation.

- ***Case 2***: Separation of fluids, recovery and purification of CO_2 and compression of the produced CO_2 for re-injection into the reservoir at a purity of some 96% v/v CO_2.

The study contains preliminary designs and cost estimates at an accuracy level of +/- 40%, for separation of the produced fluids, CO_2 recovery, compression, dehydration and re-injection of up to ~100 MMSCFD (1.8 million tpa) of CO_2 resulting from breakthrough of CO_2 from the reservoir. This (Class V) level of capital cost estimate is based on a combination of vendor budget estimates for specific pieces of equipment, information supplied by technology licensors, development of a major equipment list by SLI, and capacity-factored estimates from SLI's database for equipment and processes where SLI was not able to obtain vendor quotations.

3.0 STUDY OBJECTIVES, SCOPE AND METHODOLOGY

SLI's scope of work includes the following:

- SNC-Lavalin's scope of work is to evaluate two cases of the surface facility design in a conceptual commercial scale operation, for the selected oil field (subsequently defined as a "hypothetical" field).
- A key consideration is whether to re-inject the full CO_2 rich produced gas stream or separation the CO_2 from the produced gas before reinjection to meet reservoir needs. It was agreed to do one case with full recycle (no CO_2 separation) and the other with CO_2 separation to show the process variation and cost differences. However, in reality, each situation will vary and will depend on the reservoir performance prediction in Task 2 (by others).
- Conceptual design of the surface facilities required to support the EOR operation. Where suitable, re-use of existing infrastructure would be preferred. Capital and operating costs are then estimated based on the surface facilities and operational plan (conceptual, +/- 40% cost estimate). Capital expenditures shall be phased consistent with the development plan, adjusted for logical increments of capacity.
- Provide conceptual details of processing (separation, regeneration, dehydration and compression).
- Generate Class V capital and operating cost estimates (±40%) for the facilities provided.

In generating the study results, SNC-Lavalin used:

- Data supplied by CO_2 separation technology licensors;
- Budget-level equipment quotations from compressor vendors;
- In-house equipment and construction cost information;
- Comparison with publicly available information from other projects.

We developed:

- HYSIS™ computer models of the process for each case;
- A process flow diagram for each case;
- Heat and material balance for each case;
- Utility consumption estimates for both cases;
- Major Equipment-factored cost estimates for each case;
- Capacity-factored estimates for some process and equipment blocks in both cases;

- Operating cost estimates for each case, with and without capital charges;
- An additional cost estimate and capacity matrix for the produced fluids gathering system and CO_2 distribution system, together with field test separator costs.

Appendix 1 lists the SLI team members.

4.0 STUDY BASIS

For this study, the CO_2 source is a hypothetical oilfield where produced fluids contain increasing volumes of CO_2 over time as the CO_2 breaks through with increasing primary and recycle CO_2 injection and oil production from the EOR project. The timing and volumes have been determined by Vikor Resources on behalf of ARC. The field production will be gathered via a typical field gathering system with satellite test separators and batteries feeding a central processing plant, assumed for this purpose to be in the Judy Creek area. In normal circumstances one of the goals would be to utilize as many of the existing facilities at the existing processing plant as possible and modify and adapt them in the most cost-effective way possible to accommodate changes in gas production and increasing CO_2 concentrations. This can only be done effectively on a specific case basis. Since it is our understanding that this study is directed towards extrapolating results to a wide range of processing plants over a wide geographic area, our two simulation cases assume a stand-alone facility in each case; i.e. the inlet separation facilities we are adding are self sufficient for the volumes of produced fluids and their product streams will continue on as appropriate to feed the existing facilities. When applied to a specific location, there will be the possibility that existing processing plant facilities may be used at least in part. In our opinion the result could be some capital and operating cost savings, partially offset by some revamp costs.

Our design requires few significant amounts of external utilities other than electric power. We have assumed that all other utilities such as instrument air, natural gas, etc. will be available in modest amounts from the host plants. As is common practice in oil and gas processing facilities in western Canada our designs avoid the use of steam. The facilities we design are assumed to be totally independent of the source facilities for electric power and any synergies of integration would be developed for specific cases in the future.

Table 4.0-1 summarizes the produced fluid and CO_2 quality.

Table 4.0-1
Produced Fluid and CO_2 Quality

CO_2 Reinjection Strategy	Raw Stream CO_2 Conc. Vol %	Re-Injected Stream CO_2 Conc. Vol %	Separated CO_2 Volume Tonnes per stream Day	Separated CO_2 Volume Tonnes per calendar Year
Case1 Mixed Re-injection	88	89	5280	1,830,000
Case 2 CO_2 Re-injection	88	96	4900	1,700,000

Note that these numbers represent design values. Actual numbers vary widely from year to year. All numbers are rounded.

5.0 CASE DEFINITIONS

Two equipment configurations were established in discussion with ARC and Vikor. They are outlined below. Refer also to Process Flow Diagrams in Appendix 2.

In both cases primary separation of the fluids (oil, produced water and produced gas) is virtually identical.

Case 1 (Mixed Reinjection)

Production fluids are separated from the produced gas stream and the CO_2 rich gas is dehydrated and compressed to 2100 psig for reinjection into the reservoir. CO_2 is not separated or purified prior to compression, so the reinjected gas contains substantial amounts of methane and ethane along with the CO_2.

Case 2 (CO_2 Reinjection)

Beginning with the raw produced gas stream, production fluids are separated and the CO_2 rich gas is dehydrated and fed to a CO_2 separation unit where a "pure" (96% v/v CO_2) stream is generated. The CO_2 separation unit consists of refrigeration followed by a membrane separation package. Two other streams are produced from the CO_2 separation unit:

i A hydrocarbon gas stream, Ethane and Methane rich, that is fed to existing gas processing plant;

ii A hydrocarbon liquid stream, rich in propane and heavier components, that is expected also to be fed to the existing gas processing plant.

The "pure" CO_2 stream is compressed to 2100 psig for reinjection to the reservoir. The reinjected gas contains some 96% v/v CO_2, the balance being methane and ethane with only traces of nitrogen and virtually no heavier hydrocarbons.

To improve the CO_2 and Ethane separation a recycle gas stream is compressed and returned to the membrane CO_2 separation package inlet.

6.0 TECHNICAL DEVELOPMENT OF THE CASES

As noted above, cases 1 and 2 contemplate different approaches to produced gas handling. Case 1 permits 100% reinjection of produced gas, following elementary separation of heavier components and water. Case 2 involves separation and purification of the CO_2, and within practical limits maximizes ethane recovery. The two cases require quite different process designs and equipment and yield substantially different capital and operating costs. Not only does Case 2 require separation equipment not needed in Case 1, but also the compressor selection is different for the two cases. Case 2 also contemplates a period of one year at the beginning and four years at the end of the project, when produced gas is not separated but fully reinjected, owing to very small produced gas volumes indicated by Vikor in those time periods.

6.1 Processing Capacity Requirements

For both cases, the wide variation in quality and quantity of produced gas over the project life necessitates consideration of how best to balance the need for processing capacity against the desire to minimize and delay capital cost expenditures, avoid having large amounts of capacity standing idle for long periods, and maintain a high level of operating efficiency in the operating units.

Using some basic guidelines, SLI elected to split the processing and compression capacity into two equal trains, whose combined capacity would at the peak point of gas production be capable of handling 100% of the produced gas. The second train would be installed so as to come into operation at the point when the first train reaches 100% capacity. In concept, later in the project life when total produced gas volumes once again drop below the maximum capacity of a single train, the older train 1 would be shut down and the newer train 2 would continue to operate until the end of the project.

As noted above, for case 2, the scheme envisions delaying produced gas separation until year 2 of the project, and shutting it down in at the end of year 36. Beyond year 36, the volumes of produced gas available do not allow sustainable operation of even a single train of gas separation. During these two periods the dried produced gas would be 100% recycled without separation, similar to case 1.

The resulting schemes are as follows:

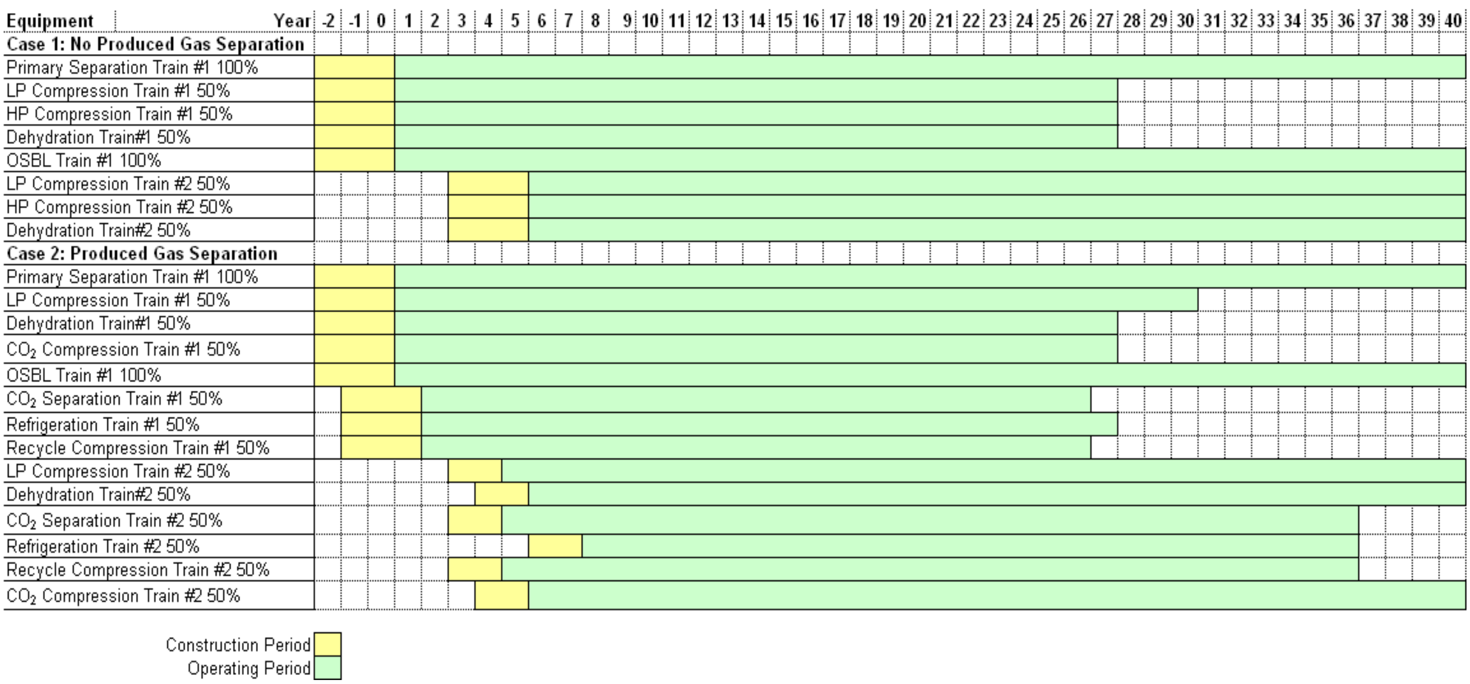
Table 6.1-1
Case Comparison – Equipment and Service Interval

Equipment	Case 1: No Gas Separation		Case 2: Gas Separation	
	Train #1	Train #2	Train #1	Train #2
Primary Separation	100% Capacity; year 1-40	Not needed	100% Capacity; year 1-40	Not needed
LP Compression	50% Capacity; year 1-27	50% Capacity; year 6-40	50% Capacity; year 1-30	50% Capacity; year 5-40
HP Compression	50% Capacity; year 1-27	50% Capacity; year 6-40	Not needed	Not needed
Dehydration (1)	50% Capacity; year 1-27	50% Capacity; year 6-40	50% Capacity; year 1-27	50% Capacity; year 6-40
CO_2 Separation	Not needed	Not needed	50% Capacity; year 2-26	50% Capacity; year 5-36
Refrigeration	Not needed	Not needed	50% Capacity; year 2-27	50% Capacity; year 8-36
Recycle Compression	Not needed	Not needed	50% Capacity; year 2-26	50% Capacity; year 5-36
CO_2 Compression	Not needed	Not needed	50% Capacity; year 1-27	50% Capacity; year 6-40
OSBL	100% Capacity; year 1-40	Not needed	100% Capacity; year 1-40	Not needed

Note (1) the dehydration system differs between the two cases, because of the need for refrigeration in Case 2.

Figure 6.1-1 provides a graphical illustration of the construction and operating periods for the equipment trains for each case.

Figure 6.1-1
Construction and Operating Period for Equipment Trains For Each Case



Other capacity variants are possible, such as breaking the processing capacity of each train into smaller amounts so the operating capacity at any time more closely matches the produced gas volume. Every actual project would do some kind of optimization via more detailed studies. In SLI's opinion the case presented here is sufficiently representative for the purposes of this study.

In each case the choice of two identical trains with staggered construction periods necessitates the use of assumptions regarding capital cost allocations, and to some extent operating costs. In our opinion, while economies of scale are lost, there are gains in being able to defer costs, and some costs are avoided because theoretically the second train is identical to the first. There are issues of operability and equipment turndown capacity, mainly with the compressors, that should be considered in the selection of the number of trains in a more specific project.

The following assumptions underlie our cost estimates for the two cases:

Equipment Economies of Scale: We are assuming none. The (unescalated) equipment costs for each train will be the same.

Engineering Design Costs: There will be some economies as a result of having two identical trains. We are also assuming that the initial engineering design will incorporate both trains. However, the time lag between first and second trains will mean some changes are likely. Given likely significant evolution of the process used for separation (membranes), the benefit of real operating history and the relatively long project life, there may be additional engineering work required to implement improvements and optimizations in the second train. This will be highly dependent on field and facility performance, timing and regulatory changes, if any.

Train 1 Pre-build for Train 2: We are assuming that Train 2 pre-build will be negligible; perhaps a few spool pieces in piping. Therefore there is no assessed effect on either Train 1 or Train 2 capital costs.

Construction Adjacent to an Existing Plant: This situation should be able to take advantage of the best of the circumstances (existing infrastructure) without facing the disadvantages (revamp costs and uncertainties). We are assuming:

- The existing control room can accommodate new facilities operations;
- Operator facilities will be adequate;
- Other than front end tie-ins there will be no need for additional intervention in the existing ISBL facilities;
- Main access roads and other general infrastructure will be adequate;
- Utilities supplies will be adequate except for power;
- No additional tankage is included except as specifically identified for the new units;
- Electric power supply will need to be upgraded twice;
- Maintenance facilities will need to be upgraded to handle additional and different equipment.

Overall, the net effect is that the percentage of direct costs associated with utilities, offsites and miscellaneous facilities will be substantially less than it would be for a green-field facility, but will still be significant and will vary from one host location to another.

Equipment Operation at Variable Throughput Rates: Electric power consumption is assumed to have a fixed and a variable component. Therefore the second train will not result in precise doubling of electric power capacity or use, nor will the yearly variation in power consumption be exactly proportional to plant throughput. The fixed component is a measurement of the total power losses and is considered constant during the project lifetime. The variable component is considered to be proportional to the plant throughput.

We are assuming that the strategy we are proposing will not require additional capital costs to allow equipment to run at high turndown ratios.

There will be some operating cost inefficiencies that result from operating equipment at high turndown ratios. These are not accounted for.

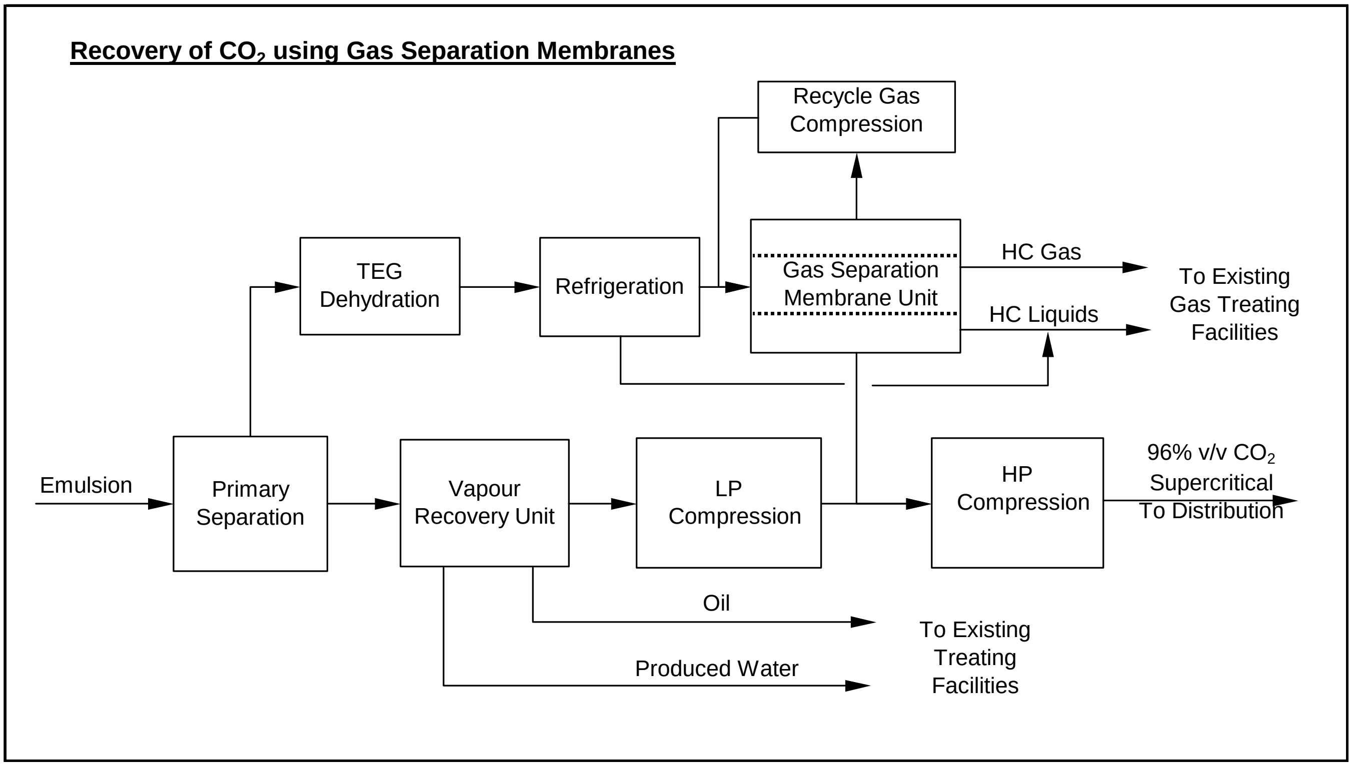
6.2 CO_2 Separation Technology

CO_2 is separated only in Case 2. Due to relatively high pressures and high CO_2 concentrations, membrane technology was considered to be likely the most appropriate to the inlet conditions.

Gas separation membranes use the difference in partial pressure between the feed gas side and the permeate side to preferentially separate a specific component of the gas stream based on its permeation rate across the membrane. Because the driving force for the membrane is the difference in partial pressure across the membrane, this poses challenges as the CO_2 purity requirement increases. As the CO_2 concentration in the permeate increases, the partial pressure differential decreases and reduces the driving force, thus requiring greater membrane areas to achieve the same separation. Equipment size and consequent capital cost premium increases very rapidly (exponentially). Membrane separation technology typically is most economically effective at reducing residual CO_2 to about 10% v/v. Using this technology it is possible to reduce residual CO_2 to about 3% v/v if required. This would equate to CO_2 product purity of about 98% v/v

The following block flow diagram illustrates the chief building blocks in a membrane gas separation system.

Figure 6.2-1
Recovery of CO_2 Using Gas Separation Membranes



6.3 State of Commercial Development: Gas Separation Membranes

Membrane gas separation technology is in use in many applications associated with CO_2, but they all exhibit at least one of the following two characteristics:

- Relatively high inlet gas stream pressure (greater than ~ 250 PSI);
- Need for compactness of equipment outweighs the capital cost disadvantages of membranes (offshore platforms).

In practice this means that membranes are used for separating CO_2 from some produced gases rather than from flue gas streams. In onshore applications where size and weight of equipment are less important, in our opinion each specific set of operating conditions requires an optimization where up to three processing options, singly or in combinations, may be considered:

- Thermal (Cryogenic) processes (Ryan-Holmes as an example);
- Chemical or physical absorption (amine separation or Benfield);
- Membrane Separation.

In our opinion, given the composition and pressure of the inlet stream in this hypothetical case and the requirement to recover ethane, membranes appeared to be the most likely approach. However, membranes and their performance are sensitive to the presence of aromatic hydrocarbons (they can degrade the membrane material), so it should be noted that in the chosen process scheme the gas stream is cooled to close to -15°C to initially remove the aromatic components.

We approached a commercial membrane supplier (NATCO-Cynara) and they were most helpful in assisting us.

We are aware of ongoing research to improve the selectivity of membranes at lower pressure differentials. They are presently not practical for flue gas CO_2 removal, largely because of the requirement to compress the entire inlet flue gas stream from atmospheric to at least 250 PSI to make the membrane work, and then losing much of that pressure across the membrane, resulting in the need to compress the CO_2 stream a second time.

SLI generated its own HYSIS™ simulation of the membrane CO_2 separation process and compared the results with licensor information and knowledge of commercial facilities.

6.4 Inlet Separation

The raw stream first encounters an inlet separator that does the initial rough separation of oil, gas and liquids. This facility is designed with two main separation vessels, but it is otherwise a single train for the entire project and as such is constructed 100% at the start.

SLI has also included a design and cost estimate for one test separator, sized for 150% of an average single producing well at peak project production. Field information used to establish the design basis was provided by ARC.

6.5 Compressors

SLI has adopted the philosophy that a CO_2 application is non-critical and therefore we will maximize the economies of scale rather than install smaller machines with the objective of increasing reliability. Although compressors may be available to handle the full flow at peak capacities, the main determining factor for train selection is the turndown capability of the compressors, given the high variability of the feed composition and flow rates. While we selected two parallel trains as the basis for this study, the suitability of more smaller trains should be evaluated when feasibility studies become more site specific.

6.6 Compressor Drivers

With the requirement for large amounts of rotating horsepower to compress the feed, CO_2, and recycle, SLI has chosen to use electric power due to the potential for sites being remote and with operations staff possibly unfamiliar with high pressure steam. Should a particular site have available excess steam generation capacity or be suitable for a steam system expansion, then steam drivers could be considered for compression. In our opinion studies of such options are very site specific and should be part of Front End Engineering Design (FEED).

6.7 Dehydration

Dehydration serves two purposes in this project. First, in both cases it is required to reduce the recycle stream water content to the point where no water condensation is possible, so that the use of stainless steel equipment and pipe can be minimized.

In case 2, a dehydration unit is also critical to lower the water content of the separated gas to approximately 11 lbs per million cubic feet prior to refrigeration, to avoid water freezing.

In our opinion a glycol-based system is the best choice for this service in both cases. These units are well established in CO_2 service for EOR operations in North America and can be manufactured by any qualified package vendor.

6.8 Refrigeration

As mentioned above, membrane performance and structural integrity are sensitive to aromatics content in the inlet gas. The raw CO_2 is cooled to near –15ºC and the aromatic and heavy compounds are removed as liquids. During this process the system reaches CO_2 liquefaction conditions and there will be a small quantity of liquid CO_2 condensed. Depending on the inlet gas composition there will also be some CO_2 – rich azeotrope mixtures that will condense during the refrigeration process.

Refrigeration can be performed using a standard propane refrigeration loop.

6.9 Membrane Separation

Usually there will be several cascading membrane separation stages involved in the process (the membrane licensor identified a requirement for 3 to 4 stages in this application). The permeate gas from the first stage will constitute the "purified" CO_2 product. The non-permeate stream will be subjected to further gas-liquid separation and becomes the feed for the second membrane stage, and so on. The permeate gas from the 2nd to 4th stages is CO_2 rich and can be recycled to the membrane system inlet after recompression, or can be delivered as CO_2 product together with the permeate from the first stage. The liquids separated from the non-permeate at each stage are combined and become the Hydrocarbon Liquid product of the plant, to be sent on to the existing gas processing facility. The non-permeate gas separated after the last membrane stage will constitute the Hydrocarbon Gas product, that will also be sent to the existing gas plant.

6.10 CO_2 Recycle

As mentioned above, the permeate gas from the 2nd to 4th membrane stages is CO_2 rich. Recycling this stream to the membrane unit inlet can improve substantially the CO_2-Hydrocarbon separation. In our design we tried to maximize Ethane recovery. We studied different scenarios from zero CO_2 recycle, achieving 45-50% overall Ethane recoveries, to higher CO_2 recycle rates, achieving over 90% overall Ethane recoveries. We selected an intermediate configuration that has about 25% recycle rate based on the membrane raw feed gas stream volume, and achieving above 75% overall Ethane recovery in the Hydrocarbon Gas stream leaving the membrane unit. In our opinion the CO_2 recycle rate and associated Ethane/Hydrocarbon recoveries are very site specific and their determination should be part of Front End Engineering Design (FEED).

6.11 Utilities

The electric power consumption of the facilities is substantial. Other facilities require minimal feed water treatment and waste disposal facilities. SLI has assumed that raw water and adequate power from the grid will be available on site. We have included substation costs for each phase of construction.

6.12 Plot Space

We have assumed that the required plot space can be made available at whatever locations are selected, immediately next to existing facilities to which our new facilities will be connected. Since layout and plot space is very specific to each site, no attempt has been made to define a layout. We would estimate that a total plot area of some 6000 m^2 or 1.5 acres is likely to be required for Case 1; 10,000 m^2 or 2.5 acres for case 2.

6.13 Control Rooms

We have assumed that sufficient capacity for additional control panels can be made available within existing control rooms at whichever sites may be selected.

6.14 Pipelines

The only pipelines to be considered are typical short run gathering lines and product lines between producing wells, injection wells and the processing facility. This study includes a generic table of pipeline costs to assist in the rough calculation of gathering and product lines and their extrapolation to other locations and configurations. It is located in Appendix 2. While part of Task 3, the extrapolation to various locations will be done by ARC. The Maximum Allowable Operating Pressure (MAOP) was assumed to be 740 psig for the gathering lines and 2250 psig for the product lines to reinjection.

Information regarding operating pressures will be specific to each location. We developed nominal values for these and discussed them with ARC, who concurred that they should be sufficiently representative for this study.

The design MAOP for the feed gathering system (740 PSIG) was determined by the anticipated wellhead pressures and the objective of remaining within the 300# ANSI standard for valves and fittings.

The design MAOP for the product CO_2 (2250 PSIG) was determined by the objective of remaining within the 900# ANSI standard for valves and fittings.

While this study contemplates only local gathering and distribution CO_2 pipelines, gathering and long distance CO_2 pipelines are well established in North America, with about 2400 km of trunk lines in operation.

In our opinion health and safety issues associated with the transport of CO_2 are manageable, and in general significantly less than those associated with the transport of gases containing H_2S. CO_2 is not toxic or flammable, but it is heavier than air and could pose a threat of asphyxiation under certain circumstances. As a general rule SLI treats CO_2 like H_2S for the purpose of designing emergency shutdown equipment.

Appendix 2 contains:

- Process flow diagrams for Cases 1 and 2;
- Heat and Material Balance for Cases 1 and 2;
- Utility requirements for Cases 1 and 2;
- Field pipeline size/cost tables.

7.0 COST ESTIMATES

Appendix 3 describes the cost estimating basis SLI used.

Appendix 4 contains the capital and operating cost estimates for both cases.

Table 7.0-1 shows the breakdown of capital costs. The estimates can be considered to be Class V, +/- 40%, first quarter 2008.

Table 7.0-1
Breakdown of Capital Costs

CASE		**1 - No CO_2 Separation**		**2 - CO_2 Separation**
UNIT	**Trains**		**Trains**	
PRIMARY SEPARATION	1	$17,770,000	1	$17,770,000
PRODUCED GAS LOW PRESSURE COMPRESSION	2	$19,710,000	2	$19,710,000
PRODUCED GAS HIGH PRESSURE COMPRESSION	2	$61,630,000		$ -
DEHYDRATION	2	$5,380,000	2	$9,330,000
CO_2 SEPARATION		$ -	2	$48,490,000
CO_2 COMPRESSION		$ -	2	$68,440,000
RECYCLE COMPRESSION		$ -	2	$32,360,000
REFRIGERATION		$ -	2	$19,830,000
		$104,490,000		**$215,930,000**
OSBL (ALLOWANCE OF 35% OF TOTAL COST)		$36,570,000		$75,580,000
OTHER COST		$ -		$ -
OTHER COST		$ -		$ -
ESTIMATE TIC		**$141,060,000**		**$291,510,000**

8.0 RESULTS

The operating cost tables are found in Appendix 4. They include a parasitic CO_2 calculation that provides a rough estimate of how much CO_2 is generated by the energy used to separate and compress the CO_2. As no CO_2 separation credits are assumed, the parasitic CO_2 noted in the table plays no part in the rest of the calculations. It is included as it is a standard parameter in all CO_2 separation studies. It becomes part of the "net CO_2 Sequestered" calculations, along with estimates of parasitic CO_2 associated with the primary CO_2 source, system losses and determinations of how much CO_2 is left in the ground.

8.1 Economic Calculations

SLI advises that we are not economists. Our economic calculations are simple and should not be used for economic decision-making. However, in our opinion they can be used as comparative tools to analyze a range of cases that have similar characteristics.

See Appendix 3 for an explanation of how operating costs are calculated. The unit cost per tonne of CO_2 is shown in two ways: The first "Cash Cost" is the total annual cash operating cost outlay divided by the annual amount of CO_2 separated and recycled. The calculation is using tonnes per year of CO_2 irrespective of the recycle stream composition, which will vary from year to year and case to case. The second set of results is from an NPV calculation and represents the constant value of CO_2 that will deliver an 8% real rate of return to the constructor/operator of the separation facilities over the life of the project. Thus, the numbers in the table illustrate a project where the proponent:

a. Does economic calculations on a 100% equity, before-tax, no-escalation or inflation basis;
b. Does project DCF calculations at an 8% discount rate and gets a NPV of zero over 2-3-year construction periods for each project phase and overall 40-year operating life.

These two conditions are sometimes described as generating a "real rate of return (of 8%)" and that term will be used in the subsequent discussion.

c. Receives the raw produced gas stream from the field at no cost;
d. Has no Owner's costs such as land, office, etc.;
e. Pays for, installs and operates all the recycle facilities;
f. Gets paid for the CO_2 recycled at no markup;
g. Receives no revenue for any product except the CO_2 (Case 1) and CO_2 + Ethane + Methane + NGLs (Case 2);
h. Gets no credit for net CO_2 stored;

i. Power cost: CAD 80.00/ MWh;

j. Natural gas cost: CAD 7.00/mcf;

k. Case 1 (no separation; no ethane recovered): CO_2 value determined by the economic calculation to deliver a NPV8 of zero (8% real rate of return);

l. Case 2 (CO_2 separated; Ethane recovered): CO_2 value determined by the economic calculation to deliver a NPV8 of zero with the following additional product values:

- Specification Ethane value of $400 per tonne. The ethane is in a stream that still requires further purification. SLI has assessed a nominal $50/tonne discount from specification ethane value to account for the existing plant's requirement to further purify the stream so the ethane can be sold as a product).
- Specification natural gas value of $7.00/mcf or CAD 185 per tonne. SLI has assessed a nominal $20/tonne discount from specification methane/natural gas value to account for the existing plant's requirement to further purify the stream so the methane can be sold as a product).
- Specification NGL (C3+) value of CAD 352/tonne. SLI has assessed a nominal $30/tonne discount from specification NGL value to account for the existing plant's requirement to further purify the stream so the NGLs can be sold as a product. This calculation is based on a nominal crude oil price of $100/bbl, 6.29 bbl/tonne at density 1.0 (API 10^o), NGL value of 80% of crude oil value, NGL density of 0.70 (API 70^o).

8.2 Observations

While it is not within SLI's mandate to perform overall economic analyses and we do not have all the information to do so, we have the following observations:

1. In Case 1 the value (cost) of CO_2 re-injected in the initial year and final six years of the project's life are very high, because of the small amounts of CO_2 being re-injected. It is acceptable to tolerate high CO_2 costs at the project's outset. However, for the final years unless the high CO_2 costs are offset by continuing significant additional oil production it would be our expectation that on economic grounds the project would be terminated short of its nominal 40-year life.
2. In Case 2 the same situation applies, but the period at the end of the project where reinjected CO_2 costs appear excessive is 7-8 years.
3. Case 2 indicates a CO_2 value of about $23.70 per tonne is required to deliver an 8% real rate of return, compared with about $19.70 in case 1. This difference has two sources:
   a. The additional equipment in case 2 is there mainly for the purpose of separating ethane, although it has additional effects of increasing the CO_2

concentration in the recycle stream and generating three more revenue streams (ethane, natural gas and NGLs).

b. The separation of an ethane stream results in about 10% of the total CO_2 that was recycled in Case 1 being lost, mainly via the ethane stream. Therefore Case 2 actually recycles 10% less CO_2 than Case 1. In a real project it is likely that the CO_2 leaving with the ethane would be separated from the ethane in the existing gas processing facilities and returned to the CO_2 recycle compressor suction, but evaluating such integration is beyond the scope of this study.

4. At the level of accuracy of our estimates, $19.70 and $23.70 for Cases 1 and 2 respectively, there is uncertainty that they may be considered to be the same number. Nonetheless, if they are close, even if the ethane separation case were to be shown to be somewhat better economically than the no-separation case, there is still the question of whether it is worth risking the additional ~$140 million in CAPEX.
5. The implication of the difference between the cases is that at a value of $350 per tonne of ethane in an impure stream, the business of separating ethane does not improve the economics of the project and may impair them somewhat.
6. The results will be particularly sensitive to revenue derived from ethane, natural gas and NGLs. Larger values for these streams may narrow the difference, while lower values and/or higher processing fees will increase the difference.
7. If reservoir conditions still dictate the need for much higher CO_2 content in the reinjection stream, the penalty for having to separate ethane is large from a capital standpoint but does not have as great an influence from an economic perspective.
8. From other information we are aware of, Case 2 at ~$23.70 per tonne of CO_2 represents a CO_2 source that is less expensive than what might be expected as a cost for raw CO_2 delivered via long-distance pipeline from an original CO_2 source that is quite pure to begin with.
9. Energy costs in the form of electric power are the largest component of operating costs.

SLI contrasted the results of our work with the knowledge that membranes are actually in use on produced gas from land-based CO_2-EOR projects, notably in SW USA. We asked the question: Under what circumstances could membranes be economically competitive in this service?

The answer appears to be that membranes would likely look more attractive if:

a. The raw stream contains no aromatics or other materials that could potentially damage the membranes;

b. The raw stream is lower in CO_2 concentration than the stream here, therefore making CO_2 separation essential to the success of the EOR project;

c. The requirement for ethane recovery was relaxed somewhat, thereby reducing or eliminating the need for a recycle stream and associated compressor.

Figure 8.1-1 shows how capital costs are split among the various components of the plant, for costs incurred in Case 1.

Figure 8.1-1
Capital Cost Breakdown for Various Components of the Plant in Case 1

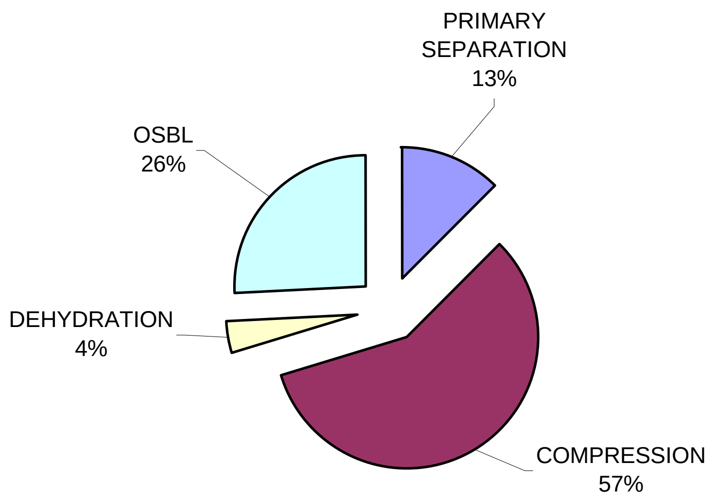


Figure 8.1-2 shows how capital costs are split among the various components of the plant, for costs incurred in Case 2.

Figure 8.1-2
Capital Cost Breakdown for Various Components of the Plant in Case 2

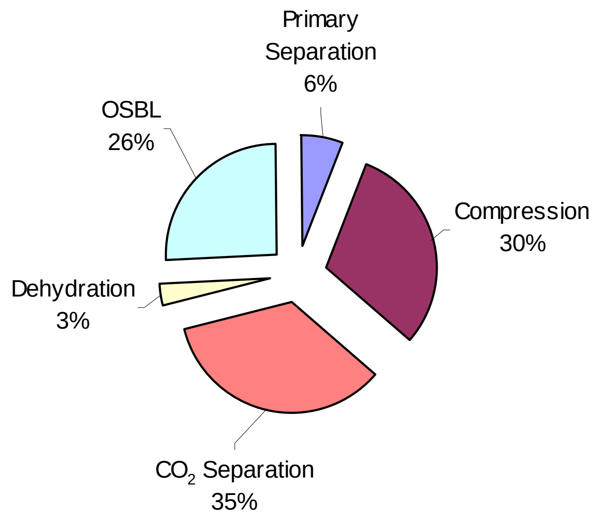


Figure 8.1-3 indicates how the operating costs are distributed in Case 1.

Figure 8.1-3
Distribution of Operating Costs, Case 1

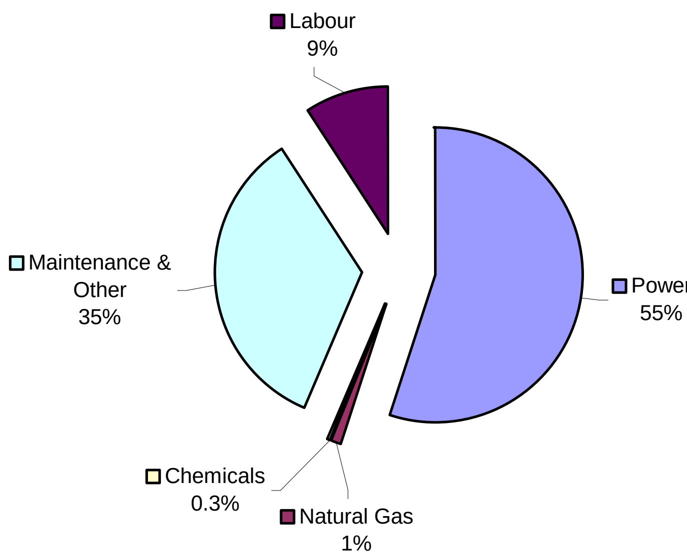
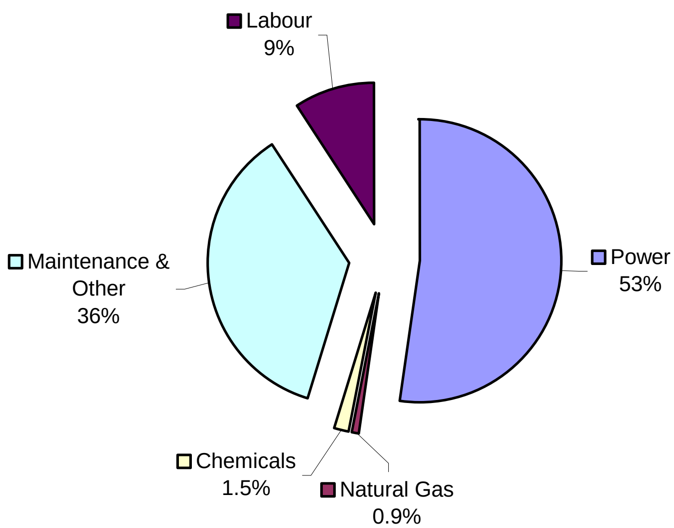


Figure 8.1-4 indicates how the operating costs are distributed in Case 2.

Figure 8.1-4
Distribution of Operating Costs, Case 2



9.0 CONCLUSIONS

In conclusion, in our opinion:

The technology for CO_2 recycle and ethane separation is commercially available.

Recycled CO_2, even when burdened with ethane recovery cost, appears to be a competitive source of CO_2 when compared with likely costs for raw purchased CO_2.

The two cases do not differ markedly in the amount of CO_2 recycled. The real difference between them is associated with how much ethane is recovered as a separate stream. The difference between the cases can therefore be seen as a rough measure of the cost of recovering an ethane-rich stream for use elsewhere.

Recovery of ethane in this hypothetical project does not appear to be an economic proposition.

While the dialogue among SLI, ARC and AERI has been extensive, the results of SLI's investigations suggests that a deeper understanding of the decision-making required of companies as they choose how to design a CO_2-EOR project requires longer analysis time periods, a greater degree of integration of the work of the reservoir engineers and the facilities engineers, and the evaluation of several more options for CO_2 separation and recycle.

10.0 RECOMMENDATIONS

Since this is a study on a "typical" Alberta situation, any specific decision on which case is most appropriate to a particular location will require additional effort to better define and optimize equipment, most appropriate number of processing trains, operational constraints, costs and revenue streams.

The study has assumed all utilities other than electric power would be available to the CO_2 separation facilities from the host plant. Any future work should look in detail into possible energy and other optimization opportunities with the host plant, which will vary from location to location.

The slightly negative result of the employment of membranes in an application that would appear to suit them suggests that further work may need to be done to better define the optimum CO_2 separation techniques in a Canadian context.

Appendix 1
SNC-Lavalin's Team Members

The following SNC-Lavalin personnel participated in the project:

Brian Fraser, P. Eng	Project Manager
Doug Macdonald, P. Eng	Project Advisor and Technical Participant
Sorin Andrei	Process Lead, Pipeline Design
Rodolfo Tellez	Process Modeling
Roger Warren, P. Eng	Licensor Package Development and Analysis, Technology Evaluation
Victor Campos	Retrofit Layout, Equipment Sizing
Herb Bowers	Cost Estimating

Appendix 2
Technical Design Parameters and Drawings

Technical Design Parameters and Drawings

V-001A/B
HP PRIMARY SEPARATOR
DIMENSIONS: 3660 mm ID x 16250 mm T/T
(NOTE 2)

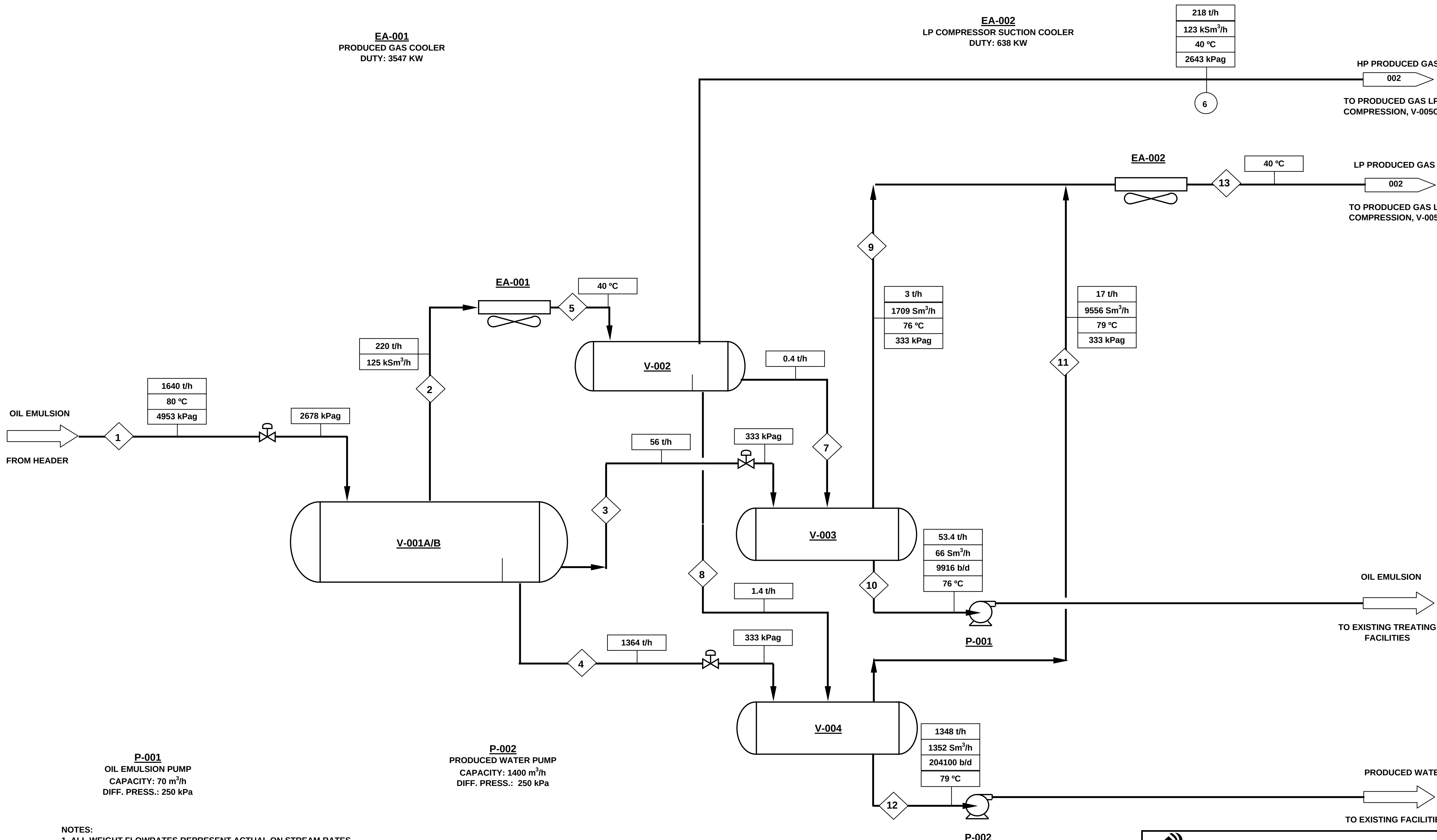
V-002
HP GAS SEPARATOR
DIMENSIONS: 1220 mm ID x 3350 mm T/T

V-003
LP OIL SEPARATOR
DIMENSIONS: 1750 mm ID x 5600 mm T/T

V-004
LP WATER SEPARATOR
DIMENSIONS: 4500 mm ID x 12500 mm T/T

EA-001
PRODUCED GAS COOLER
DUTY: 3547 KW

EA-002
LP COMPRESSOR SUCTION COOLER
DUTY: 638 KW



P-001
OIL EMULSION PUMP
CAPACITY: 70 m^3/h
DIFF. PRESS.: 250 kPa

P-002
PRODUCED WATER PUMP
CAPACITY: 1400 m^3/h
DIFF. PRESS.: 250 kPa

NOTES:
1. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
2. TWO VESSELS IN PARALLEL INSTALLED
3. ONE TRAIN 100% CAPACITY INSTALLED

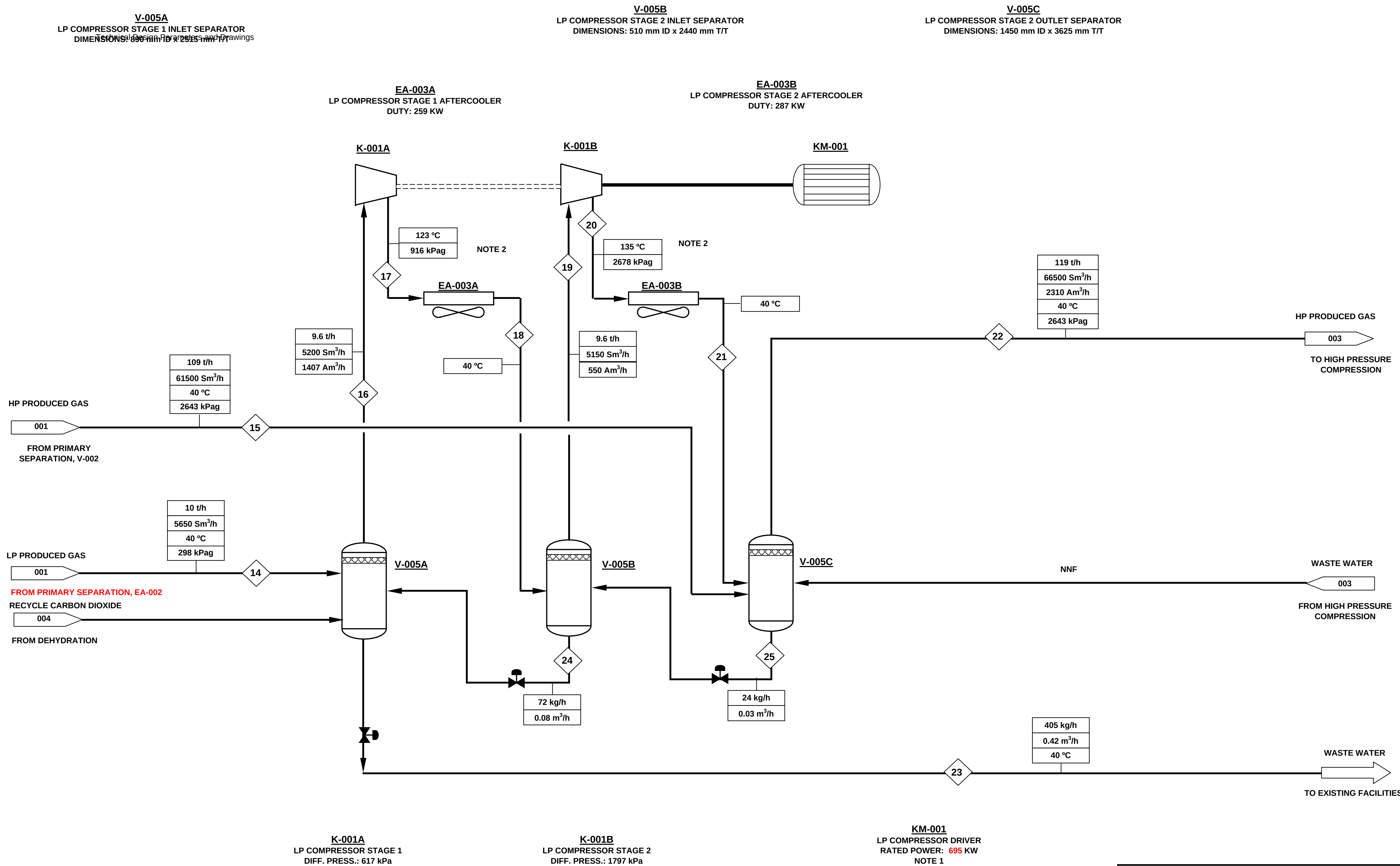
PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE: AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 1: NO CO2 SEPARATION
PRIMARY SEPARATION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
FEB 2008	NTS	SA	DM	BF

DOCUMENT NO. 017935-49-10-PFD-001 Rev.A



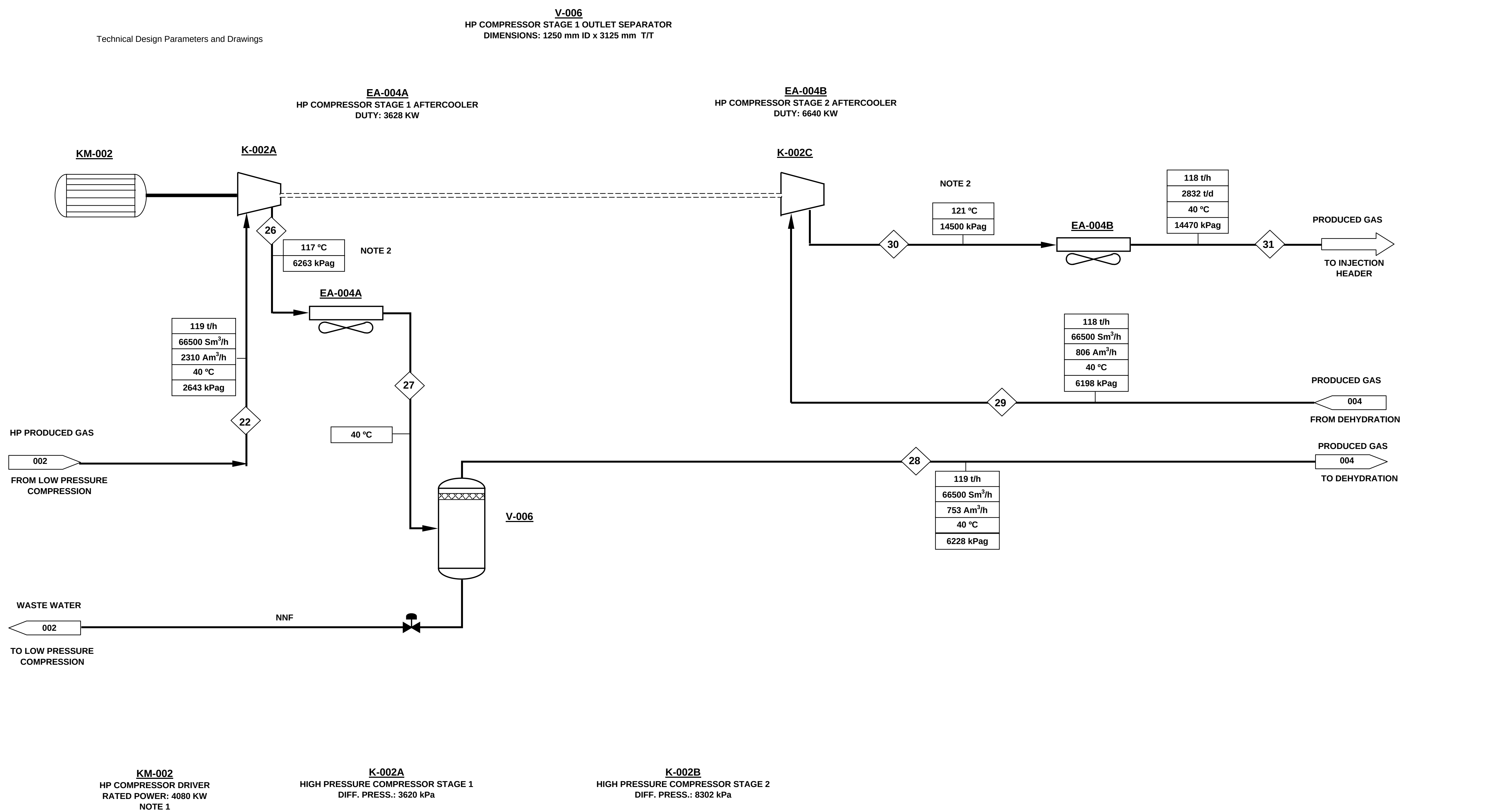
NOTES:
1. RATED POWER INCLUDES 10% POWER LOSS
2. ALL DISCHARGE PRESSURES AND TEMPERATURES ARE THEORETICAL. ACTUAL OPERATION PARAMETERS BY COMPRESSOR VENDOR
3. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
4. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE	AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY PROCESS FLOW DIAGRAM CASE 1: NO CO2 SEPARATION PRODUCED GAS LOW PRESSURE COMPRESSION			
DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
FEB 2008	NTS	SA	DM	BF
DOCUMENT NO.	017935-49-10-PFD-002 Rev. A			

Technical Design Parameters and Drawings



NOTES:
1. RATED POWER INCLUDES 10% POWER LOSS
2. ALL DISCHARGE PRESSURES AND TEMPERATURES ARE THEORETICAL. ACTUAL OPERATION PARAMETERS BY COMPRESSOR VENDOR
3. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
4. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

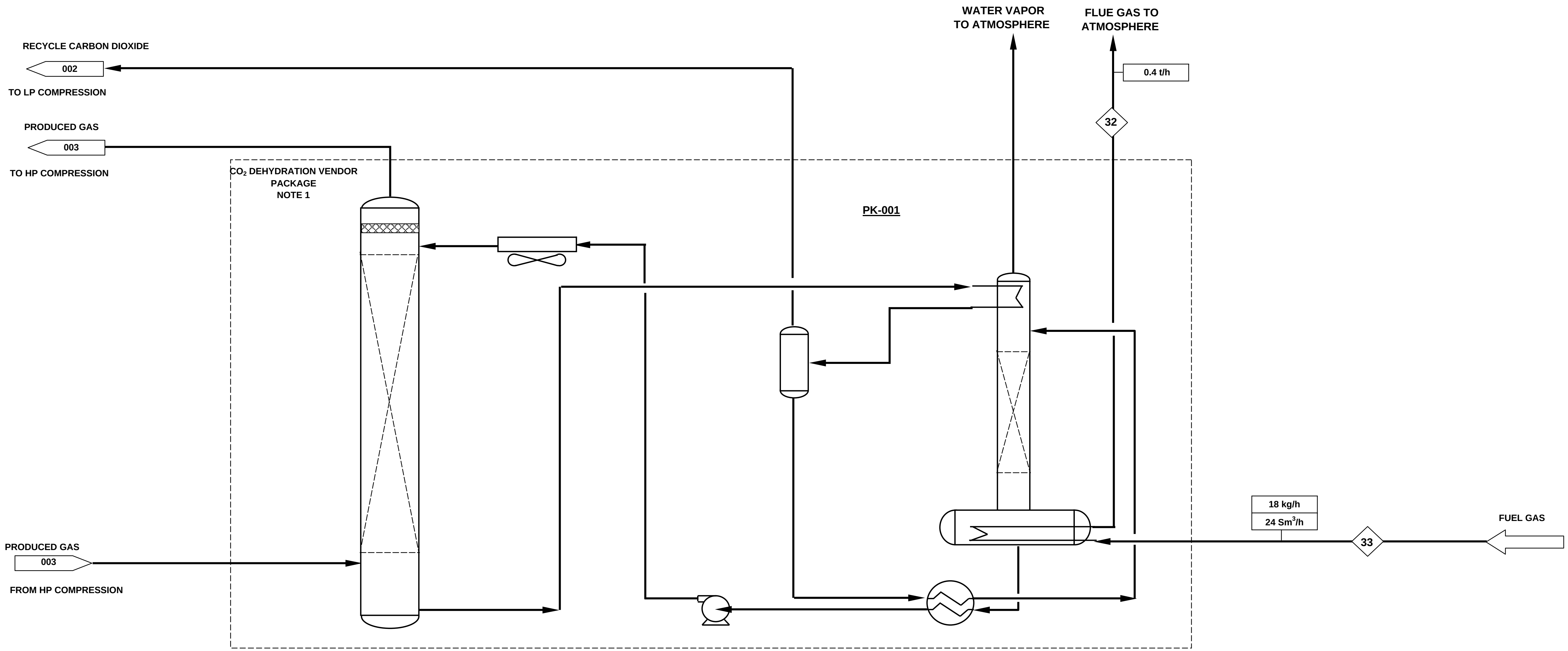
SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 1: NO CO2 SEPARATION
PRODUCED GAS HIGH PRESSURE COMPRESSION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
#REF!	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-10-PFD-003 Rev. A

PK-001
CO2 DEHYDRATION PACKAGE
CAPACITY: 2832 TPD (DRY GAS)



NOTES:
1. VENDOR PACKAGE INTERNAL CONFIGURATION IS FOR INFORMATION ONLY. THE ACTUAL CONFIGURATION MAY BE DIFFERENT.
2. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
3. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 1: NO CO2 SEPARATION
PRODECED GAS DEHYDRATION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
#REF!	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-10-PFD-004 Rev. A

Technical Design Parameters and Drawings

V-001A/B
HP PRIMARY SEPARATOR
DIMENSIONS: 3660 mm ID x 16250 mm T/T
CAPACITY: 197 m^3
(NOTE 2)

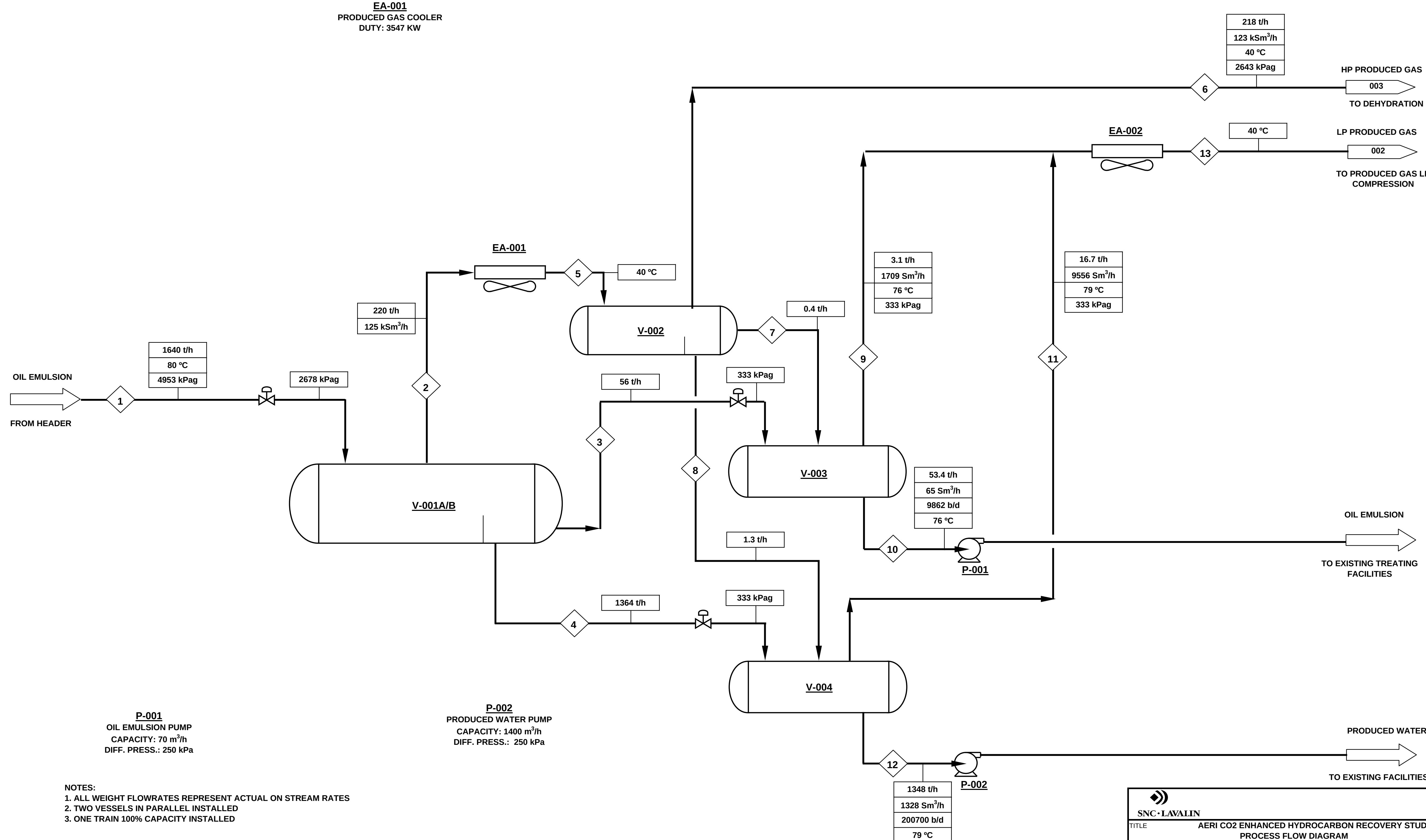
V-002
HP GAS SEPARATOR
DIMENSIONS: 1220 mm ID x 3350 mm T/T
CAPACITY: 4.9 m^3

V-003
LP OIL SEPARATOR
DIMENSIONS: 1750 mm ID x 5600 mm T/T
CAPACITY: 16.3 m^3

V-004
LP WATER SEPARATOR
DIMENSIONS: 4500 mm ID x 12500 mm T/T
CAPACITY: 247 m^3

EA-002
LP COMPRESSOR SUCTION COOLER
DUTY: 638 KW

EA-001
PRODUCED GAS COOLER
DUTY: 3547 KW



P-001
OIL EMULSION PUMP
CAPACITY: 70 m^3/h
DIFF. PRESS.: 250 kPa

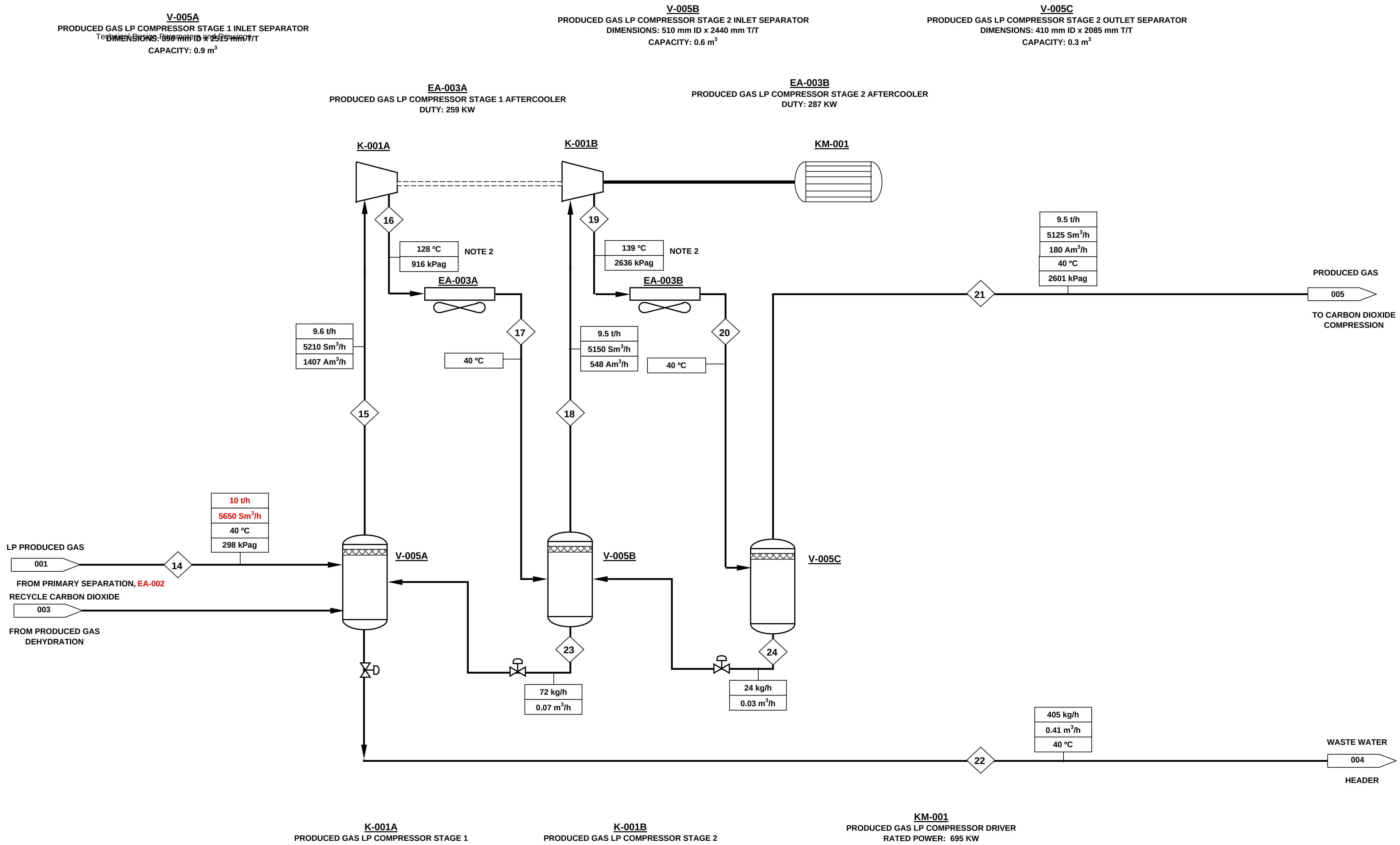
P-002
PRODUCED WATER PUMP
CAPACITY: 1400 m^3/h
DIFF. PRESS.: 250 kPa

NOTES:
1. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
2. TWO VESSELS IN PARALLEL INSTALLED
3. ONE TRAIN 100% CAPACITY INSTALLED

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE	AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY PROCESS FLOW DIAGRAM CASE 2: CO2 SEPARATED PRIMARY SEPARATION			
DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
Mar-08	NTS	SA	DM	BF
DOCUMENT NO.	017935-49-20-PFD-001 Rev.B			



NOTES:
1. RATED POWER INCLUDES 10% POWER LOSS
2. ALL DISCHARGE PRESSURES AND TEMPERATURES ARE THEORETICAL. ACTUAL OPERATION PARAMETERS BY COMPRESSOR VENDOR
3. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
4. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

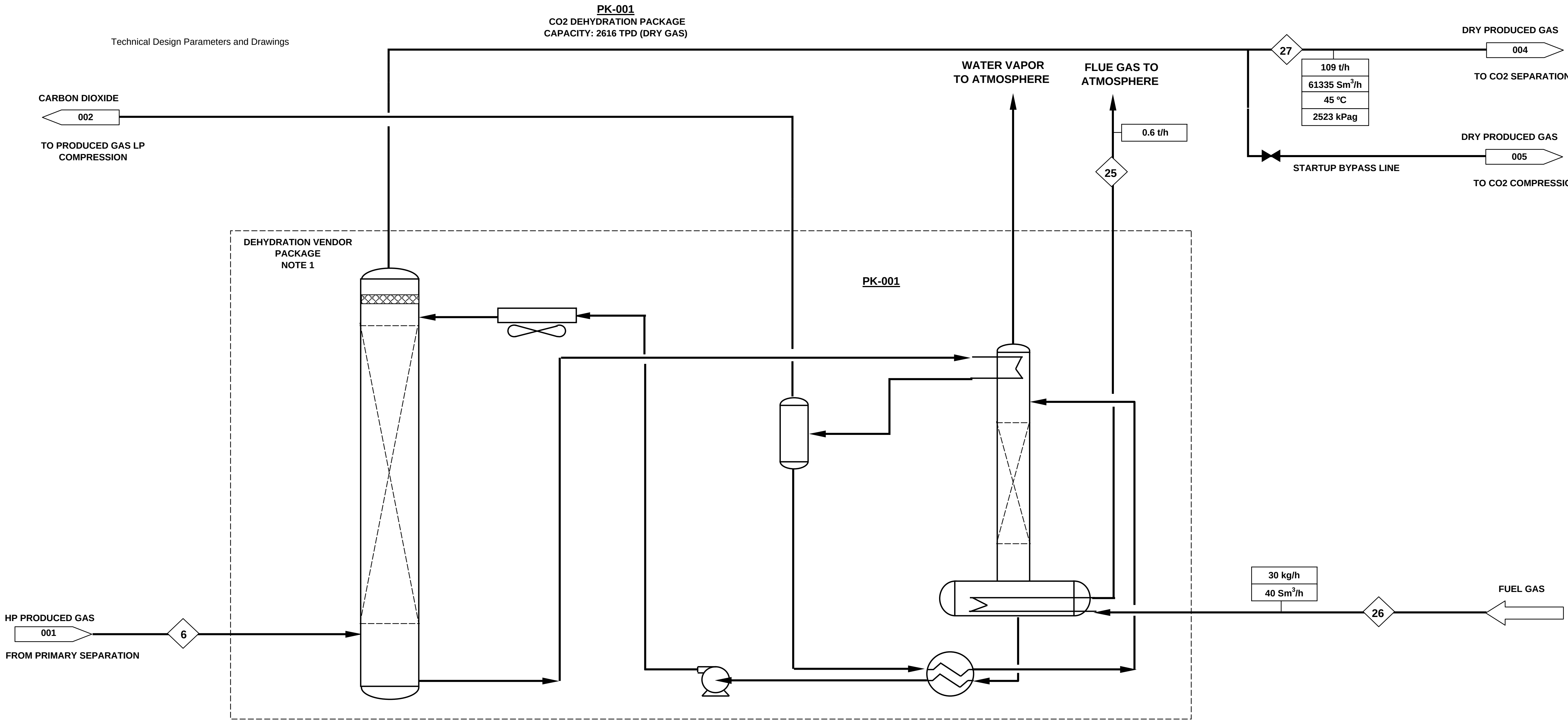
SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 2: CO2 SEPARATED
PRODUCED GAS LOW PRESSURE COMPRESSION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
Mar-08	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-20-PFD-002 Rev. B

Technical Design Parameters and Drawings



NOTES:
1. VENDOR PACKAGE INTERNAL CONFIGURATION IS FOR INFORMATION ONLY. THE ACTUAL CONFIGURATION MAY BE DIFFERENT.
2. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
3. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

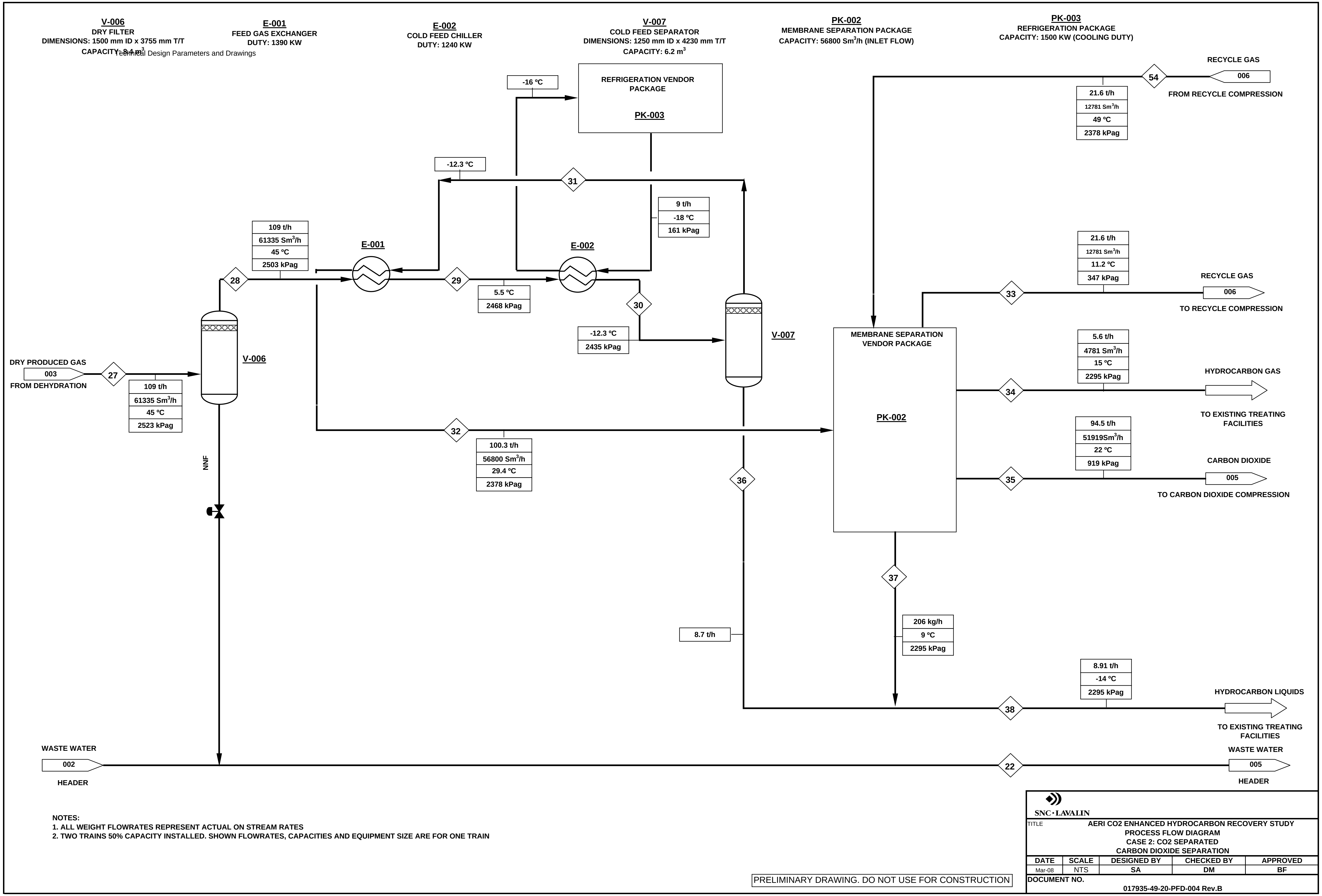
PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

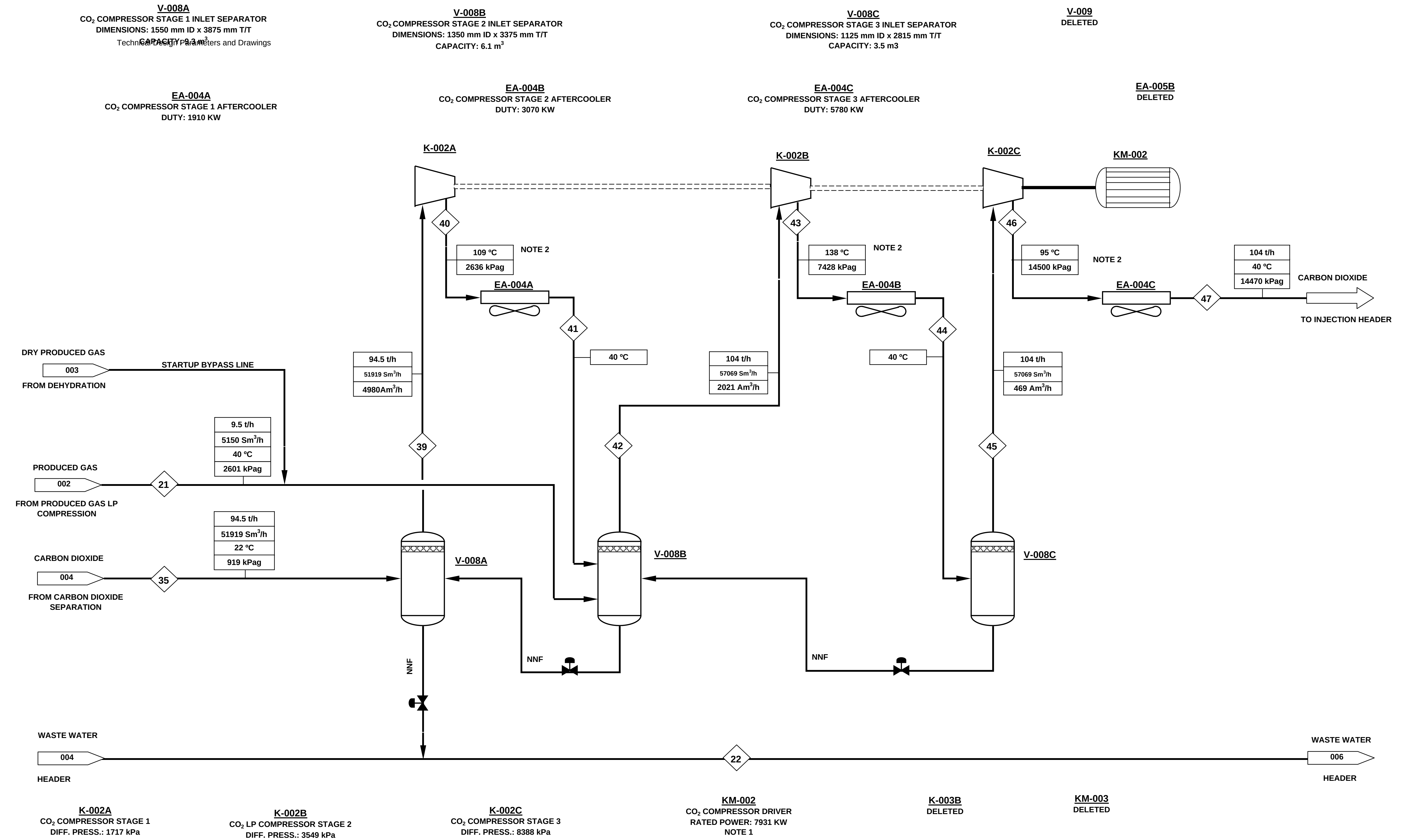
SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 2: CO2 SEPARATED
PRODUCED GAS DEHYDRATION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
Mar-08	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-20-PFD-003 Rev. B


V-006
DRY FILTER
DIMENSIONS: 1500 mm ID x 3755 mm T/T
CAPACITY: 8.4 m3
E-001
FEED GAS EXCHANGER
DUTY: 1390 KW
E-002
COLD FEED CHILLER
DUTY: 1240 KW
V-007
COLD FEED SEPARATOR
DIMENSIONS: 1250 mm ID x 4230 mm T/T
CAPACITY: 6.2 m3
PK-002
MEMBRANE SEPARATION PACKAGE
CAPACITY: 56800 Sm3/h (INLET FLOW)
PK-003
REFRIGERATION PACKAGE
CAPACITY: 1500 KW (COOLING DUTY)
REFRIGERATION VENDOR PACKAGE
PK-003
-16 ºC
-12.3 ºC
31
9 t/h
-18 ºC
161 kPag
RECYCLE GAS
006
FROM RECYCLE COMPRESSION
54
21.6 t/h
12781 Sm3/h
49 ºC
2378 kPag
109 t/h
61335 Sm3/h
45 ºC
2503 kPag
E-001
E-002
28
29
5.5 ºC
2468 kPag
30
-12.3 ºC
2435 kPag
V-007
V-006
DRY PRODUCED GAS
003
FROM DEHYDRATION
27
109 t/h
61335 Sm3/h
45 ºC
2523 kPag
21.6 t/h
12781 Sm3/h
11.2 ºC
347 kPag
RECYCLE GAS
33
006
TO RECYCLE COMPRESSION
MEMBRANE SEPARATION VENDOR PACKAGE
PK-002
5.6 t/h
4781 Sm3/h
15 ºC
2295 kPag
HYDROCARBON GAS
34
TO EXISTING TREATING FACILITIES
32
100.3 t/h
56800 Sm3/h
29.4 ºC
2378 kPag
94.5 t/h
51919Sm3/h
22 ºC
919 kPag
CARBON DIOXIDE
35
005
TO CARBON DIOXIDE COMPRESSION
NNF
36
37
206 kg/h
9 ºC
2295 kPag
8.7 t/h
8.91 t/h
-14 ºC
2295 kPag
HYDROCARBON LIQUIDS
38
TO EXISTING TREATING FACILITIES
WASTE WATER
002
HEADER
22
WASTE WATER
005
HEADER
NOTES:
1. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
2. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN
PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION
SNC·LAVALIN
TITLE
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 2: CO2 SEPARATED
CARBON DIOXIDE SEPARATION
DATE
SCALE
DESIGNED BY
CHECKED BY
APPROVED
Mar-08
NTS
SA
DM
BF
DOCUMENT NO.
017935-49-20-PFD-004 Rev.B



NOTES:
1. RATED POWER INCLUDES 10% POWER LOSS
2. ALL DISCHARGE PRESSURES AND TEMPERATURES ARE THEORETICAL. ACTUAL OPERATION PARAMETERS BY COMPRESSOR VENDOR
3. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
4. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

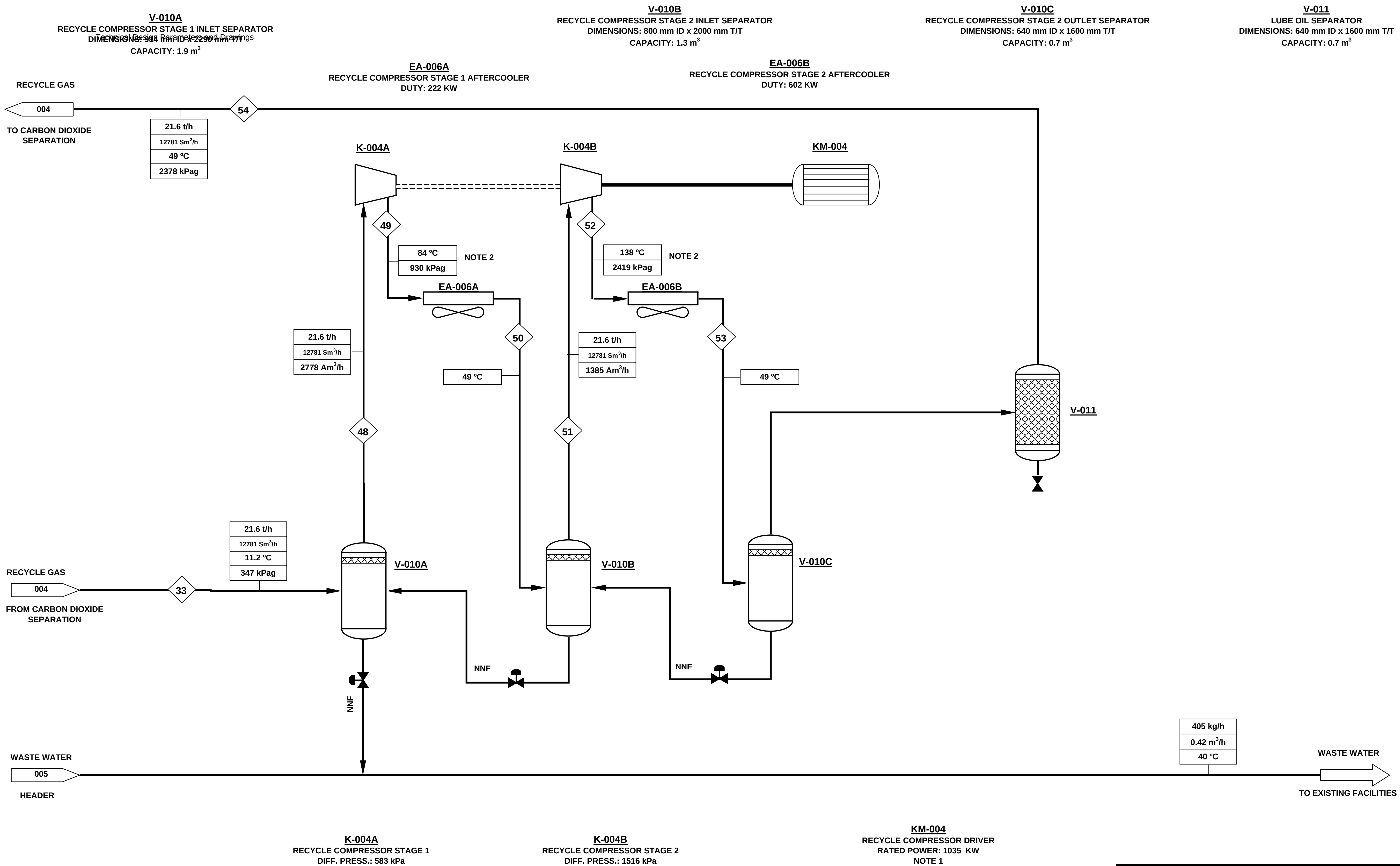
PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 2: CO2 SEPARATED
CARBON DIOXIDE COMPRESSION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
Mar-08	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-20-PFD-005 Rev. B



NOTES:
1. RATED POWER INCLUDES 10% POWER LOSS
2. ALL DISCHARGE PRESSURES AND TEMPERATURES ARE THEORETICAL. ACTUAL OPERATION PARAMETERS BY COMPRESSOR VENDOR
3. ALL WEIGHT FLOWRATES REPRESENT ACTUAL ON STREAM RATES
4. TWO TRAINS 50% CAPACITY INSTALLED. SHOWN FLOWRATES, CAPACITIES AND EQUIPMENT SIZE ARE FOR ONE TRAIN

PRELIMINARY DRAWING. DO NOT USE FOR CONSTRUCTION

SNC·LAVALIN

TITLE AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROCESS FLOW DIAGRAM
CASE 2: CO2 SEPARATED
RECYCLE COMPRESSION

DATE	SCALE	DESIGNED BY	CHECKED BY	APPROVED
Mar-08	NTS	SA	DM	BF

DOCUMENT NO.
017935-49-20-PFD-006 Rev. B

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HEAT AND MATERIAL BALANCE	Client:	ARC	Rev./Date	By	Checked	Approved
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY. CASE 1 - NO CO_2 SEPARATION	Project:	017935	A / Mar. 2008	VC	SA	BF
	Doc. #:	017935-49-10-HM-001	B / Sep. 2008	SA	DM	BF
	Page	1 of 3				

Stream Number	Units	1	2	3	4	5	6	7	8	9	10	11	12	13
Stream Description		Oil Emulsion from Header	Produced Gas	Recovered Oil Emulsion	Recovered Water	Cooled Produced Gas	HP Produced Gas	V-002 Separated Oil	V-002 Separated Water	LP Produced Gas from V-003	Oil Emulsion	LP Produced Gas from V-004	Produced Water	LP Produced Gas
Vapor Weight Fraction		0.123	1.00	0.00	0.00	0.99	1.00	0.00	0.00	1.00	0.00	1.000	0.000	0.925
Temperature	ºC	80	80	80	80	40	40	40	40	75.5	75.5	79.2	79.2	40.0
Pressure	kPag	4953	2678	2678	2678	2678	2643	2643	2643	333	333	333	333	298
Molar Rate	kg-mol/hr	80690	5277	363	75050	5277	5200	4.5	72.8	72.3	295	404	74719	477
Mass Rate	Ton/hr	1640	220.05	56.13	1363	220.05	218.33	0.39	1.33	3.12	53.40	16.71	1348.06	19.83
Actual Volumetric Flow	Am^3/hr	3841	5047	72.28	1409	4269	4267	0.50	1.33	474	69.33	2678.10	1396.23	2816.76
Standard Volumetric Flow	Sm^3/hr	-------	124800	67.4	1340	-------	123000	0.48	1.31	1709	817	9556	1328	-------
Enthalpy	GJ/h	-23.217	-1.868	-0.137	-21.201	-1.881	-1.859	-0.001	-0.021	-0.025	-0.113	-0.152	-21.070	-0.179
Molecular Weight		20.32	41.70	154.70	18.17	41.70	41.99	88.19	18.26	43.05	181.00	41.33	18.04	41.61
Actual Density	kg/m^3	426.90	43.60	776.50	968.00	51.55	51.17	793.10	999.99	6.56	770.20	6.24	965.50	7.04
Dynamic Viscosity	cP	-------	0.018	1.349	0.367	-------	0.016	0.530	0.674	0.016	1.773	0.016	0.355	-------
Thermal Conductivity	W/m-ºC	-------	0.025	0.111	0.663	-------	0.022	0.103	0.621	0.022	0.134	0.022	0.669	-------
Specific Heat	kJ/kg-ºC	-------	1.127	2.293	4.315	-------	1.140	1.230	4.256	1.057	2.312	0.974	4.350	-------
Surface Tension	dyne/cm	-------	-------	16.74	62.16	-------	------	15.90	68.83	------	20.70	------	62.420	-------
Compressibility		-------	0.9077	------	------	-------	0.8648	-------	-------	0.9834	-------	0.9831	-------	-------
Composition														
CO_2	% weight	13.64	91.57	5.45	1.40	91.57	92.25	13.23	2.29	86.27	0.80	95.10	0.24	93.72
Water	% weight	82.07	0.70	0.04	98.58	0.70	0.11	0.02	97.71	0.63	0.01	4.60	99.74	3.98
N_2	% weight	0.01	0.08	0.00	0.00	0.08	0.08	0.00	0.00	0.02	0.00	0.00	0.00	0.01
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	% weight	0.29	2.15	0.06	0.00	2.15	2.16	0.12	0.00	1.06	0.00	0.00	0.00	0.17
C2	% weight	0.41	2.96	0.26	0.00	2.96	2.98	0.72	0.00	3.89	0.06	0.00	0.00	0.61
C3	% weight	0.14	1.01	0.21	0.00	1.01	1.02	0.71	0.00	2.40	0.09	0.00	0.00	0.38
C4	% weight	0.08	0.53	0.27	0.00	0.53	0.53	1.11	0.00	1.82	0.18	0.00	0.00	0.29
$C5^+$	% weight	3.36	1.01	93.70	0.02	1.01	0.86	84.09	0.00	3.90	98.86	0.29	0.02	0.85

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HEAT AND MATERIAL BALANCE	Client:	ARC	Rev./Date	By	Checked	Approved
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY. CASE 1 - NO CO2 SEPARATION	Preoject:	017935	A / Mar. 2008	VC	SA	BF
	Doc. #:	017935-49-10-HM-001	B / Sep. 2008	SA	DM	BF
	Page	2 of 3				

Stream Number	Units	14	15	16	17	18	19	20	21	22	23	24	25	26
Stream Description		LP Produced Gas to Train A	HP Produced Gas to Train A	1st stage LP Compressor Suction	1st stage LP Compressor Discharge	Cooled 1st stage LP Compressor Discharge	2nd stage LP Compressor Suction	2nd stage LP Compressor Discharge	Cooled 2nd stage LP Compressor Discharge	HP Produced Gas	Waste Water	1st Stage Waste Water	2nd Stage Waste Water	1st Stage HP Compressor Discharge
Vapor Weight Fraction		0.925	1.000	1.000	1.000	0.989	1.000	1.000	0.995	1.000	0.000	0.000	0.000	1.000
Temperature	ºC	40	40	40	123.2	40	40	134.8	40	40	40	40	40	116.7
Pressure	kPag	298	2643	298	916	881	881	2678	2643	2643	298	881	2643	6263
Molar Rate	kg-mol/hr	238.3	2600	220.3	220.3	220.3	217.9	217.9	217.9	2816.6	21.5	3.6	1.1	2816.6
Mass Rate	Ton/hr	9.92	109.2	9.58	9.58	9.58	9.51	9.51	9.51	118.65	0.41	0.07	0.02	118.65
Actual Volumetric Flow	Am^3/hr	1408.38	2133.6	1406.23	697.48	549.42	549.33	251.67	176.79	2309.73	0.41	0.07	0.03	1239.18
Standard Volumetric Flow	Sm^3/hr	-------	61500	5210	5210	-------	5150	5150	-------	66650	0	0	0	66650
Enthalpy	GJ/h	-0.090	-0.930	-0.084	-0.084	-0.085	-0.084	-0.083	-0.084	-1.013	-0.006	-0.001	0.000	-1.006
Molecular Weight		41.61	41.99	43.47	43.47	43.47	43.65	43.65	43.65	42.13	18.85	20.16	21.64	42.13
Actual Density	kg/m^3	7.04	51.17	6.81	13.73	17.43	17.35	37.87	53.91	51.37	981.70	963.10	955.90	95.75
Dynamic Viscosity	cP	-------	0.016	0.015	0.020	-------	0.015	0.021	-------	0.016	0.771	0.869	0.930	0.021
Thermal Conductivity	W/m-ºC	-------	0.022	0.019	0.026	-------	0.019	0.028	-------	0.022	0.580	0.509	0.434	0.031
Specific Heat	kJ/kg-ºC	-------	1.140	0.927	0.995	-------	0.953	1.053	-------	1.136	4.201	4.026	3.814	1.269
Surface Tension	dyne/cm	-------	------	-------	-------	-------	-------	-------	-------	-------	59.87	59.42	58.47	-------
Compressibility		-------	0.8648	0.9801	0.9772	-------	0.9513	0.9461	-------	0.8644	-------	-------	-------	0.8638
Composition														
CO_2	% weight	93.72	92.25	96.97	96.97	96.97	97.46	97.46	97.46	92.69	0.47	1.45	4.94	92.69
Water	% weight	3.98	0.11	0.76	0.76	0.76	0.31	0.31	0.31	0.11	94.67	86.86	78.35	0.11
N_2	% weight	0.01	0.08	0.01	0.01	0.01	0.01	0.01	0.01	0.07	0.00	0.00	0.00	0.07
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	% weight	0.17	2.16	0.17	0.17	0.17	0.18	0.18	0.18	2.00	0.00	0.00	0.00	2.00
C2	% weight	0.61	2.98	0.64	0.64	0.64	0.64	0.64	0.64	2.79	0.00	0.01	0.03	2.79
C3	% weight	0.38	1.02	0.39	0.39	0.39	0.39	0.39	0.39	0.97	0.00	0.01	0.06	0.97
C4	% weight	0.29	0.53	0.30	0.30	0.30	0.30	0.30	0.30	0.51	0.00	0.03	0.13	0.51
$C5^+$	% weight	0.85	0.86	0.76	0.76	0.76	0.72	0.72	0.72	0.85	4.86	11.64	16.48	0.85

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HEAT AND MATERIAL BALANCE			Rev./Date	By	Checked	Approved
	Client:	ARC	A / Mar. 2008	VC	SA	BF
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY. CASE 1 - NO CO2 SEPARATION	Project:	017935	B / Sep. 2008	SA	DM	BF
	Doc. #:	017935-49-10-HM-001				
	Page	3 of 3				

Stream Number	Units	27	28	29	30	31	32	33
Stream Description		Cooled 1st Stage HP Compressor Discharge	Produced Gas to Dehydration	Produced Gas from Dehydration	2nd Stage HP Compressor Discharge	Produced Gas to Injection Header	Flue Gas to Atmosphere	Fuel Gas to Dehydration
Vapor Weight Fraction		1.000	1.000	1.000	1.000	1.000	1.000	1.000
Temperature	ºC	40	40	40	121	40	200	40
Pressure	kPag	6228	6228	6198	14500	14470	0	8.7
Molar Rate	kg-mol/hr	2817	2817	2808	2808	2808	25.8	2.1
Mass Rate	Ton/hr	118.65	118.65	118.44	118.44	118.44	0.72	0.04
Actual Volumetric Flow	Am^3/hr	752.86	752.86	801.92	471.33	188.31	999.65	48.63
Standard Volumetric Flow	Sm^3/hr	66650	66650	66450	66450	66450	609	49
Enthalpy	GJ/h	-1.019	-1.019	-1.015	-1.009	-1.033	-0.002	0.000
Molecular Weight		42.13	42.13	42.18	42.18	42.18	27.87	17.68
Actual Density	kg/m^3	157.60	157.60	147.70	251.30	629.00	0.72	0.75
Dynamic Viscosity	cP	0.019	0.019	0.019	0.027	0.045	0.023	0.012
Thermal Conductivity	W/m-ºC	0.028	0.028	0.027	0.041	0.041	0.036	0.034
Specific Heat	kJ/kg-ºC	1.899	1.899	1.734	1.710	3.132	1.151	2.155
Surface Tension	dyne/cm	-------	-------	-------	-------	-------	-------	-------
Compressibility		0.6498	0.6498	0.6801	0.7490	0.3752	0.9997	0.9976
Composition								
CO_2	% weight	92.69	92.69	92.77	92.77	92.77	13.59	5.23
Water	% weight	0.11	0.11	0.03	0.03	0.03	10.54	0.00
N_2	% weight	0.07	0.07	0.07	0.07	0.07	72.82	0.00
O_2	% weight	0.00	0.00	0.00	0.00	0.00	3.06	0.00
C1	% weight	2.00	2.00	2.01	2.01	2.01	0.00	82.64
C2	% weight	2.79	2.79	2.79	2.79	2.79	0.00	10.56
C3	% weight	0.97	0.97	0.97	0.97	0.97	0.00	1.25
C4	% weight	0.51	0.51	0.51	0.51	0.51	0.00	0.33
$C5^+$	% weight	0.85	0.85	1.36	1.36	1.36	0.00	0.00

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HEAT AND MATERIAL BALANCE	**Client:**	**ARC**	**Rev./Date**	**By**	**Checked**	**Approved**
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY. CASE 1 - CO_2 SEPARATION	**Project:**	**017935**	A / Mar. 2008	VC	SA	BF
	Doc. #:	**017935-49-20-HM-001**	B / Mar. 2008	VC	SA	BF
	Page	**1 of 5**	C / Sep/ 2008	SA	DM	BF

Stream Number	**Units**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Stream Description		Oil Emulsion from Header	Produced Gas	Recovered Oil Emulsion	Recovered Water	Cooled Produced Gas	HP Produced Gas to Dehydration	V-002 Separated Oil	V-002 Separated Water	LP Produced Gas from V-003	Oil Emulsion	LP Produced Gas from V-004	Produced Water	LP Produced Gas
Vapor Weight Fraction		0.123	1.0	0.0	0.0	0.99	1.0	0.0	0.0	1.0	0.0	1.0	0.0	0.9
Temperature	ºC	80	80	80	80	40	40	40	40	76	76	79	79	40
Pressure	kPag	4953	2678	2678	2678	2678	2643	2643	2643	333	333	333	333	298
Molar Rate	kg-mol/hr	80690	5277	363	75050	5277	5200	4.48	72.80	72.28	295	404	74719	477
Mass Rate	Ton/hr	1640	220	56	1363	220	218	0.39	1.33	3.12	53	17	1348	20
Actual Volumetric Flow	Am^3/hr	3841	5047	72	1409	4269	4267	0.50	1.33	474	69	2678	1396	2817
Standard Volumetric Flow	Sm^3/hr	-------	124800	67	1340	-------	123000	0.48	1.31	1709	817	9556	1328	-------
Enthalpy	GJ/h	-23.217	-1.868	-0.137	-21.201	-1.881	-1.859	-0.001	-0.021	-0.025	-0.113	-0.152	-21.070	-0.179
Molecular Weight		20.320	41.700	154.700	18.170	41.700	41.990	88.190	18.260	43.050	181.000	41.330	18.040	41.610
Actual Density	kg/m^3	426.900	43.600	776.500	968.000	51.550	51.170	793.100	999.990	6.563	770.200	6.238	965.500	7.044
Dynamic Viscosity	cP	-------	0.018	1.349	0.367	-------	0.016	0.530	0.674	0.016	1.773	0.016	0.355	-------
Thermal Conductivity	W/m-ºC	-------	0.025	0.111	0.663	-------	0.022	0.103	0.621	0.022	0.134	0.022	0.669	-------
Specific Heat	kJ/kg-ºC	-------	1.127	2.293	4.315	-------	1.140	1.230	4.256	1.057	2.312	0.974	4.350	-------
Surface Tension	dyne/cm	-------	-------	16.740	62.160	-------	------	15.900	68.830	------	20.700	------	62.420	-------
Compressibility		-------	0.908	------	------	-------	0.865	-------	-------	0.983	-------	0.983	-------	-------
Composition														
CO_2	% weight	13.64	91.57	5.45	1.40	91.57	92.25	13.23	2.29	86.27	0.80	95.10	0.24	93.72
Water	% weight	82.07	0.70	0.04	98.58	0.70	0.11	0.02	97.71	0.63	0.01	4.60	99.74	3.98
N_2	% weight	0.01	0.08	0.00	0.00	0.08	0.08	0.00	0.00	0.02	0.00	0.00	0.00	0.01
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	% weight	0.29	2.15	0.06	0.00	2.15	2.16	0.12	0.00	1.06	0.00	0.00	0.00	0.17
C2	% weight	0.41	2.96	0.26	0.00	2.96	2.98	0.72	0.00	3.89	0.06	0.00	0.00	0.61
C3	% weight	0.14	1.01	0.21	0.00	1.01	1.02	0.71	0.00	2.40	0.09	0.00	0.00	0.38

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Stream Number	Units	14	15	16	17	18	19	20	21	22	23	24	25	26
Stream Description		LP Produced Gas to Train A	1st stage LP Compressor Suction	1st stage LP Compressor Discharge	Cooled 1st stage LP Compressor Discharge	2nd stage LP Compressor Suction	2nd stage LP Compressor Discharge	Cooled 2nd stage LP Compressor Discharge	HP Produced Gas	Waste Water	1st Stage Waste Water	2nd Stage Waste Water	Flue Gas to Atmosphere	Fuel Gas to Dehydration
Vapor Weight Fraction		0.92	1.00	1.00	0.99	1.00	1.00	0.99	1.00	0.000	0.000	0.000	1.000	1.000
Temperature	ºC	40	40	123	40	40	135	40	40	40.0	40.0	40.0	200.0	40.0
Pressure	kPag	298	298	916	881	881	2678	2643	2601	298.3	880.7	2601.0	0.0	8.7
Molar Rate	kg-mol/hr	238	220	220	220	218	218	218	217	21.5	3.6	1.1	21.0	1.7
Mass Rate	Ton/hr	10	10	10	10	10	10	10	9.48	0.41	0.07	0.02	0.58	0.03
Actual Volumetric Flow	Am^3/hr	1408	1406	697	549	549	252	177	179.94	0.41	0.07	0.03	813.51	39.57
Standard Volumetric Flow	Sm^3/hr	-------	5210	5210	-------	5150	5150	-------	5125.0	0.40	0.07	0.02	495.5	39.6
Enthalpy	GJ/h	-0.090	-0.084	-0.084	-0.085	-0.084	-0.083	-0.084	-0.084	-0.004	-0.001	0.000	-0.001	0.000
Molecular Weight		41.610	43.470	43.470	43.470	43.650	43.650	43.650	43.73	18.85	20.17	21.65	27.87	17.68
Actual Density	kg/m^3	7.044	6.809	13.730	17.430	17.350	37.870	53.910	52.82	981.70	963.00	955.60	0.72	0.75
Dynamic Viscosity	cP	-------	0.015	0.020	-------	0.015	0.021	-------	0.016	0.771	0.870	0.932	0.023	0.012
Thermal Conductivity	W/m-ºC	-------	0.019	0.026	-------	0.019	0.028	-------	0.021	0.580	0.509	0.434	0.036	0.034
Specific Heat	kJ/kg-ºC	-------	0.927	0.995	-------	0.953	1.053	-------	1.083	4.201	4.025	3.813	1.151	2.154
Surface Tension	dyne/cm	-------	-------	-------	-------	-------	-------	-------	-------	59.87	59.42	58.47		-------
Compressibility		-------	0.980	0.977	-------	0.951	0.946	-------	0.8616	-------	-------	-------	0.9997	0.9976
Composition														
CO_2	% weight	93.72	96.97	96.97	96.97	97.46	97.46	97.46	97.69	0.47	1.45	4.87	13.59	5.23
Water	% weight	3.98	0.76	0.76	0.76	0.31	0.31	0.31	0.11	94.67	86.83	78.35	10.54	0.00
N_2	% weight	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	72.82	0.00
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.06	0.00
C1	% weight	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	82.64
C2	% weight	0.61	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.00	0.01	0.03	0.00	10.56
C3	% weight	0.38	0.39	0.39	0.39	0.39	0.39	0.39	0.40	0.00	0.01	0.06	0.00	1.25
C4	% weight	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.00	0.03	0.13	0.00	0.33
$C5^+$	% weight	0.85	0.76	0.76	0.76	0.72	0.72	0.72	0.67	4.86	11.67	16.56	0.00	0.00

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Stream Number	Units	27	28	29	30	31	32	33	34	35	36	37	38	39
Stream Description		Produced Gas from Dehydration	Dry Produced Gas	Cold Produced Gas	Chilled Produced Gas	Cold Feed Gas	CO_2 Separation Feed Gas	Recycle Gas to Compression	Hydrocarbon Gas	Carbon Dioxide to Compression	Liquid Hydrocarbon from V-007	Liquid Hydrocarbon from CO_2 Separation	Hydrocarbon Liquids	1st Stage CO_2 Compressor Suction
Vapor Weight Fraction		1.00	1.00	1.00	0.93	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	1.00
Temperature	ºC	45.0	44.8	5.5	-12.3	-12.3	29.4	11.2	14.7	21.8	-12.6	8.9	-14.3	21.8
Pressure	kPag	2522.7	2502.7	2467.7	2434.7	2412.7	2377.7	346.8	2294.7	918.7	2412.7	2294.7	2294.7	918.7
Molar Rate	kg-mol/hr	2592.9	2592.9	2592.9	2592.9	2401.3	2401.3	540.5	201.8	2195.6	191.8	4.3	196.0	2195.6
Mass Rate	Ton/hr	109.01	109.01	109.01	109.01	100.30	100.30	21.57	5.55	94.54	8.70	0.21	8.91	94.54
Actual Volumetric Flow	Am^3/hr	2297.76	2315.81	1891.13	1579.55	1584.28	2112.05	2776.59	167.43	4970.74	9.20	0.36	9.56	4970.74
Standard Volumetric Flow	Sm^3/hr	61335.6	61335.6	-------	-------	56800.0	56800.0	12871.0	4781.0	51919.2	21.0	0.7	21.7	51919.2
Enthalpy	GJ/h	-0.927	-0.927	-0.932	-0.937	-0.865	-0.860	-0.183	-0.021	-0.839	-0.072	-0.001	-0.072	-0.839
Molecular Weight		42.04	42.04	42.04	42.04	41.77	41.77	39.91	27.51	43.06	45.39	48.14	45.45	43.06
Actual Density	kg/m^3	47.44	47.07	57.64	69.01	63.31	47.49	7.77	33.16	19.02	946.4	563.5	814.4	19.02
Dynamic Viscosity	cP	0.016	0.016	-------	-------	0.013	0.015	0.013	0.011	0.015	0.162	0.149	0.168	0.015
Thermal Conductivity	W/m-ºC	0.022	0.022	-------	-------	0.018	0.021	0.018	0.026	0.018	0.109	0.095	0.110	0.018
Specific Heat	kJ/kg-ºC	1.122	1.121	-------	-------	1.269	1.120	0.988	2.050	0.950	2.288	2.381	2.247	0.950
Surface Tension	dyne/cm	-------	-------	-------	-------	-------	-------	-------	-------	-------	11.78	9.57	12.21	-------
Compressibility		0.8788	0.8796	-------	-------	0.7655	0.8665	0.9740	0.8306	0.9420	-------	-------	-------	0.9420
Composition														
CO_2	% weight	92.40	92.40	92.40	92.40	93.01	93.01	90.53	9.87	98.07	85.34	5.16	83.49	98.07
Water	% weight	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.10	0.00
N_2	% weight	0.08	0.08	0.08	0.08	0.08	0.08	0.26	0.86	0.04	0.01	0.02	0.01	0.04
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	% weight	2.17	2.17	2.17	2.17	2.33	2.33	4.76	23.98	1.06	0.00	2.15	0.37	1.06
C2	% weight	2.98	2.98	2.98	2.98	3.08	3.08	3.96	42.81	0.71	1.92	17.47	2.28	0.71
C3	% weight	1.02	1.02	1.02	1.02	0.96	0.96	0.41	14.88	0.10	1.73	19.05	2.19	0.10
C4	% weight	0.53	0.53	0.53	0.53	0.39	0.39	0.07	5.93	0.00	2.18	23.79	2.75	0.00
$C5^+$	% weight	0.82	0.82	0.82	0.82	0.15	0.15	0.01	1.68	0.01	8.73	32.36	8.83	0.01

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Stream Number	Units	40	41	42	43	44	45	46	47	48	49	50	51	52
Stream Description		1st Stage CO_2 Compressor Discharge	Cooled 1st Stage CO_2 Compressor Discharge	2nd Stage CO_2 LP Compressor Suction	2nd Stage CO_2 Compressor Discharge	Cooled 2nd Stage CO_2 Compressor Discharge	3rd Stage CO_2 Compressor Suction	3rd Stage CO_2 Compressor Discharge	Carbon Dioxide to Injection	1st Stage Recycle Compressor Suction	1st Stage Recycle Compressor Discharge	Cooled 1st Stage Recycle Compressor Discharge	2nd Stage Recycle Compressor Suction	2nd Stage Recycle Compressor Discharge
Vapor Weight Fraction		1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000	1.000
Temperature	ºC	109.4	40.0	40.0	137.9	40.0	40.0	94.7	40.0	11.170	84.2	48.9	48.9	137.8
Pressure	kPag	2635.7	2600.7	2600.7	7427.7	7392.7	7392.7	14498.7	14468.7	347	930.0	902.4	902.4	2419.0
Molar Rate	kg-mol/hr	2195.6	2195.6	2412.4	2411.9	2411.9	2411.9	2411.9	2411.9	541	540.5	540.5	540.5	540.5
Mass Rate	Ton/hr	94.54	94.54	104.02	104.02	104.02	104.02	104.02	104.02	22	21.57	21.57	21.57	21.57
Actual Volumetric Flow	Am^3/hr	2392	1841	2021	957	469	469	329	151	2777	1513	1384.53	1384.53	702.64
Standard Volumetric Flow	Sm^3/hr	51919	51919	57044	57069	57069	57069	57069	57069	12871	12871	12871.0	12871.0	12871.0
Enthalpy	GJ/h	-0.831	-0.838	-0.923	-0.913	-0.929	-0.929	-0.925	-0.942	-0.183	-0.181	-0.182	-0.182	-0.180
Molecular Weight		43.06	43.06	43.13	43.13	43.13	43.13	43.13	43.13	39.910	39.91	39.91	39.91	39.91
Actual Density	kg/m^3	39.59	51.44	51.56	108.70	221.80	221.80	316.60	687.30	7.769	14.26	15.6	15.6	30.70
Dynamic Viscosity	cP	0.020	0.016	0.016	0.023	0.021	0.021	0.029	0.048	0.013	0.017	0.015	0.015	0.020
Thermal Conductivity	W/m-ºC	0.026	0.021	0.021	0.032	0.031	0.031	0.043	0.039	0.018	0.025	0.022	0.022	0.030
Specific Heat	kJ/kg-ºC	1.045	1.075	1.076	1.215	2.709	2.709	2.042	3.145	0.988	1.067	1.044	1.044	1.147
Surface Tension	dyne/cm	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Compressibility		0.9360	0.8687	0.8680	0.8742	0.5598	0.5598	0.6505	-------	0.974	0.9714	0.9604	0.9604	0.9591
Composition										0.000				
CO_2	% weight	98.07	98.07	98.04	98.04	98.04	98.04	98.04	98.04	90.53	90.53	90.53	90.53	90.53
Water	% weight	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
N_2	% weight	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.26	0.26	0.26	0.26	0.26
O_2	% weight	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	% weight	1.06	1.06	0.98	0.98	0.98	0.98	0.98	0.98	4.76	4.76	4.76	4.76	4.76
C2	% weight	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	3.96	3.96	3.96	3.96	3.96
C3	% weight	0.10	0.10	0.13	0.13	0.13	0.13	0.13	0.13	0.41	0.41	0.41	0.41	0.41
C4	% weight	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.07	0.07	0.07	0.07	0.07
$C5^+$	% weight	0.01	0.01	0.06	0.06	0.06	0.06	0.06	0.06	0.01	0.01	0.01	0.01	0.01

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Stream Number	Units	53	54
Stream Description		Cooled 2nd Stage Recycle Compressor Discharge	Recycle Gas
Vapor Weight Fraction		1.000	1.000
Temperature	ºC	48.9	48.9
Pressure	kPag	2378.0	2378.0
Molar Rate	kg-mol/hr	540.5	540.5
Mass Rate	Ton/hr	21.57	21.57
Actual Volumetric Flow	Am^3/hr	525.61	525.61
Standard Volumetric Flow	Sm^3/hr	12871.0	12871.0
Enthalpy	GJ/h	-0.182	-0.182
Molecular Weight		39.91	39.91
Actual Density	kg/m^3	41.0	41.0
Dynamic Viscosity	cP	0.016	0.016
Thermal Conductivity	W/m-ºC	0.023	0.023
Specific Heat	kJ/kg-ºC	1.132	1.132
Surface Tension	dyne/cm	-------	-------
Compressibility		0.9005	0.9005
Composition			
CO_2	% weight	90.53	90.53
Water	% weight	0.00	0.00
N_2	% weight	0.26	0.26
O_2	% weight	0.00	0.00
C1	% weight	4.76	4.76
C2	% weight	3.96	3.96
C3	% weight	0.41	0.41
C4	% weight	0.07	0.07
$C5^+$	% weight	0.01	0.01

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TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL POWER	NORMAL EL. POWER	DESIGN DUTY	DESIGN EL. POWER	VOLTAGE	CONTINUOUS	INTERMITTENT		REMARKS
		kW	kW	kW	kW	V	kW	kW		
	MAIN OPERATION FACILITIES									
P-001	OIL EMULSION PUMP		7		8		7			
P-002	PRODUCED WATER PUMP		17		21		17			
EA-001	PRODUCED GAS COOLER		22		26		22			
EA-002	LP COMPRESSOR SUCCTION COOLER		9		11		9			
EA-003 A	LP COMPRESSOR STAGE 1 AFTERCOOLER		8		10		8			
EA-003 B	LP COMPRESSOR STAGE 2 AFTER COOLER		4		5		4			
EA-004 A	HP COMPRESSOR STAGE 1 AFTERCOOLER		44		53		44			
EA-004 B	HP COMPRESSOR STAGE 2 AFTERCOOLER		52		62		52			
PK-001	CO_2 DEHYDRATION PACKAGE		2		2		2			
K-001	LP COMPRESSORS		844		1015		844			
K-002	HP COMPRESSORS		7408		8890		7408			
	TOTAL MAIN OPERATION AREA				**10103**		**8417**			
	CONTINGENCY			15%	1515		1515			
	TOTAL				**11618**		**9933**			

NOTES:
1. Electrical Power for Air Coolers include a 80% efficiency factor.
2. All the design values include a design margin (20%)
3. Preliminary Issue. To be updated based on vendor data

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TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL	DESIGN (1)	CONTINUOUS	INTERMITTENT			REMARKS
		SCMH	SCMH	SCMH	SCMH			
PK-01	CO_2 DEHYDRATION PACKAGE	48.00	57.60	48				
	TOTAL	**48.00**	**57.60**	**48**	**0**			

NOTES:
1. Preliminary Issue. To be updated based on vendor data.

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TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL	DESIGN (1)	CONTINUOUS	INTERMITTENT			REMARKS
		kg/hr	kg/hr	kg/hr	kg/hr			
PK-01	CO_2 DEHYDRATION PACKAGE							
	TEG	12.0	14.0	12.0	9707			

NOTES:
1. All the design values include a design margin (20%)
2. Preliminary Issue. To be updated based on vendor data.
3. To be defined by the vendor

SNC·LAVALIN	Client	Project:	Contract #:	017935		
	ARC	AERI CO_2 ENHANCED HYDROCARBON RECOVERY STUDY	Document #:	017935-49-20-UB-001		
			Date	By	Checked	Approved
			Mar. 2008	VC	SA	BF
			Rev.:		Page	1 of 3

TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL POWER	NORMAL EL. POWER	DESIGN DUTY	DESIGN EL. POWER	VOLTAGE	CONTINUOUS	INTERMITTENT		REMARKS
		kW	kW	kW	kW	V	kW	kW		
	MAIN OPERATION FACILITIES									
P-001	OIL EMULSION PUMP		7		8		7			
P-002	PRODUCED WATER PUMP		17		21		17			
EA-001	PRODUCED GAS COOLER		22		26		22			
EA-002	LP COMPRESSOR SUCCTION COOLER		9		11		9			
	TOTAL PRIMARY SEPARATION		**55**		**66**				**11**	**kW Power Loss**
EA-003 A	PROD. GAS LP COMPRESSOR STG 1 AFTERCOOLER		9		11		9			
EA-003 B	PROD. GAS LP COMPRESSOR STG 2 AFTERCOOLER		7		9		7			
K-001	PRODUCED GAS LP COMPRESSOR		442		530		442			
	TOTAL PROD GAS LP COMPRESSION		**458**		**550**				**92**	**kW Power Loss**
PK-001	CO_2 DEHYDRATION PACKAGE		5		6		5			
	TOTAL DEHYDRATION		**5**		**6**				**1**	**kW Power Loss**
PK-002	MEMBRANE SEPARATION PACKAGE		5		6					
	HC LIQUIDS PUMPS		10		12					
	TOTAL CO2 SEPARATION		**15**		**18**				**3**	**kW Power Loss**
EA-004 A	CO_2 COMPRESSOR STAGE 1 AFTERCOOLER		80		96		80			
EA-004 B	CO_2 COMPRESSOR STAGE 2 AFTERCOOLER		90		108		90			
EA-004 C	CO_2 COMPRESSOR STAGE 3 AFTERCOOLER		304		365		304			
K-002	CO_2 COMPRESSORS		5047		6056		5047			
	TOTAL CO2 COMPRESSION		**5521**		**6625**				**1104**	**kW Power Loss**
EA-006 A	RECYCLE COMPRESSOR STAGE 1 AFTERCOOLER		4		5		4			
EA-006 B	RECYCLE COMPRESSOR STAGE 2 AFTERCOOLER		4		5		4			
K-004	RECYCLE COMPRESSOR		941		1129		941			
	TOTAL RECYCLE COMPRESSION		**950**		**1140**				**190**	**kW Power Loss**
PK-003	REFRIGARATION PACKAGE		932		1118					
	TOTAL REFRIGERATION		**932**		**1118**				**186**	**kW Power Loss**
	TOTAL MAIN OPERATION AREA				**19047**		**6989**			
	CONTINGENCY			15%	2857		2857			
	TOTAL				**21904**		**9846**			

NOTES:
1. Electrical Power for Air Coolers include a 80% efficiency factor.
2. All the design values include a design margin (20%)
3. Preliminary Issue. To be updated based on vendor data

SNC·LAVALIN	Client	Project:	Contract #: 017935			
	ARC	AERI CO_2 ENHANCED HYDROCARBON RECOVERY STUDY	Document #: 017935-49-20-UB-001			
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TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL	DESIGN (1)	CONTINUOUS	INTERMITTENT			REMARKS
		SCMH	SCMH	SCMH	SCMH			
PK-01	CO_2 DEHYDRATION PACKAGE	40.00	48.00	40				
	TOTAL	**40.00**	**48.00**	**40**	**0**			

NOTES:

1. Preliminary Issue. To be updated based on vendor data.

SNC·LAVALIN	Client	Project:	Contract #:	017935		
	ARC	AERI CO_2 ENHANCED HYDROCARBON RECOVERY STUDY	Document #:	017935-49-20-UB-001		
			Date	By	Checked	Approved
			Mar. 2008	VC	SA	BF
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TAG NUMBER	EQUIPMENT DESCRIPTION	NORMAL	DESIGN (1)	CONTINUOUS	INTERMITTENT			REMARKS
		kg/hr	kg/hr	kg/hr	kg/hr			
PK-001	CO_2 DEHYDRATION PACKAGE							
	TEG	11.0	13.0	11.0	10695			
PK-002	MEMBRANE SEPARATION PACKAGE							
	MEMBRANES							
PK-003	REFRIGERATION PACKAGE							
	REFRIGERANT							

NOTES:
1. All the design values include a design margin (20%)
2. Preliminary Issue. To be updated based on vendor data.
3. To be defined by the vendor

SNC·LAVALIN	PROCESS CALCULATION			Rev	Date	By	Checked	Approved
	Project: 017935	Client:	ARC	A	18-Mar-08	VC	SA	DM
	AERI CO_2 Enhanced Hydrocarbon Recovery Study. Gathering and Distribution System Capacity/Cost Estimation			B	7-Apr-08	VC	SA	DM
Calculation #:	017935-49-10-CA-002		Contract No.:	017935	Sheet No.	1	of	1

EMULSION COLLECTION LINES

Temperature	80 ºC	/	176 ºF
Pressure	5054.13 kPa	/	720.00 PSIG
Gas/Liquid Mixture Density, ρ_k	426.89 kg/m^3	/	26.65 lb/ft^3
Sizing Criteria: Erosional Velocity, V_e	8.86 m/sec	/	29.06 ft/sec

Nominal Size	Estimated Capacity @ 70% V_e		Estimated Cost ($/1000 m)		Remarks
in	Am^3/h	t/h	(X65 Lined CS)	Fiberglass	
3	106.5	45.4	$128,250	$117,393	
4	183.3	78.3	$171,000	$154,307	
6	416.0	177.6	$256,500	$248,373	
8	720.4	307.5	$357,200	$342,439	
10	1135.5	484.8	$446,500	$436,505	
12	1628.7	695.3	$535,800	$530,571	
16	2544.8	1086.3	$773,600	n/a	
20	4083.0	1743.0	$967,000	n/a	

CO_2 INJECTION LINES

Temperature		40 ºC	/		104 ºF
Pressure		14567 kPa	/		2100 PSIG
Density, ρ_k		629.00 kg/m^3	/		39.27 lb/ft^3
Sizing Criteria: Pressure Drop	ΔP:	23 - 68 kPa/100 m	/	υ :	2.1 - 3.7 m/sec (1)

Nominal Size	Calculated Velocity	Pressure Drop	Estimated Maximum Capacity		Estimated Cost ($/1000 m)	Remarks
in	m/sec	kPa/100m	Am^3/h	t/h	(X70 CS)	
3	2.11	33.8	32.5	20.5	$104,850	
4	2.10	23.8	56.0	35.2	$139,800	
6	3.00	29.5	181.6	114.2	$209,700	
8	3.70	31.9	392.3	246.8	$295,960	
10	3.70	23.7	641.4	403.5	$376,350	
12	3.70	19.0	931.6	586.0	$456,110	
16	3.70	14.2	1518.1	954.9	$678,300	
20	3.70	10.7	2435.6	1532.0	$871,430	

TEST SEPARATOR

Nominal Size	Rated Pressure	Rated Temperature	Estimated Maximum Inlet Capacity		Estimated Cost	
in	kPag	ºC	Am^3/h	t/h	Equipment Cost	TIC
35" ID x 78.5" T/T	5100	100	33.2	13.5	$ 68,000	$ 197,000

Appendix 3
Cost Estimating Basis

Technical Basis for Cost Estimating

1. CO_2 Separation

Case 1 requires no gas separation. Produced water and oil are separated in a primary separator and the remainder of the stream is re-compressed and dehydrated for injection back into the reservoir.

For Case 2, CO_2 Separation costs were estimated based on preliminary sizing of the major equipment – separation, dehydration, refrigeration, recycle and compression.

The CO_2 membrane separation unit capital cost was provided as a package price by one of the most experienced vendors, Natco-Cynara.

Equipment sizing was done based on Heat and Material Balance data generated using a HYSYS™ computer model created for each of the cases and, where available, validated based on Heat & Material Balance data and equipment sizing data provided by a licensor or generated from in-house information. The design basis was established by taking the year of greatest fluid production (operating year 19) and assuming two trains of 50% capacity each.

The year-to-year variation in stream volumes required a separate HYSIS™run for each case, for each year of operation, for a total of 80 simulation cases. Vikor and Pengrowth provided us with extensive and detailed data on project performance over its life. Due to the short time frame and limited study scope SLI made a series of simplifying assumptions to prepare the raw input data for use in the HYSIS™ model:

a. The Oil phase was assumed to have a constant composition established using operating year 19 data.
b. Annual oil phase volumes were supplied by Vikor and used as provided.
c. Water phase was assumed to be 100% water. No dissolved salts were considered.
d. Annual water phase volumes were supplied by Vikor and used as provided.
e. Gas phase hydrocarbon composition assumed constant using operating year 19 data.
f. Annual gas phase hydrocarbon volumes were supplied by Vikor and used as provided.
g. Produced CO_2 was assumed to be 100% CO_2.

h. Annual CO_2 volumes were supplied by Vikor and used as provided.

Utilities consumptions were estimated based on the Heat & Material Balance data using the following assumptions:

1. All drivers inside the unit will be electric powered;
2. All the cooling will be air-cooling (but see Case 2 compressors, below).

Electric Power requirements were estimated based on estimated power consumption of the major compressors and pumps.

2. CO_2 and Gas Compressor Packages

Compressors were estimated based on updated 2008 vendor quotations.

For low capacity compressors such as Low Pressure Compressors and Recycle Compressors we considered reciprocating compressors with water/glycol cooled cylinders.

For High Pressure and High Capacity compressors, such as High Pressure and CO_2 Compressors, we considered centrifugal compressors. Following the manufacturer's recommendation, cooling to the compressors is provided by a closed loop water/glycol cooling package, with air-coolers. SLI incorporated these in the compressor package costs.

Compressors and pump capacities were factored based on volumetric inlet flow.

3. CO_2 and Gas Compression After-coolers and Separators

These were estimated based on SLI in-house cost data.

The after-coolers were sized using HTFS software.

Separators were sized using an SLI/GPSA method.

4. CO_2 Dehydration

This equipment uses Triethylene Glycol (TEG) for dehydration. Costs were estimated based on a 2004 vendor quotation, updated in 2007. The base capacity for the Dehydration unit is maximum 106.7 MMSCFD (19,704 Sm^3/h) inlet flow and maximum 11 lb/MMSCF water content in the outlet CO_2, as defined by year 19 operating conditions.

The Dehydration package includes:

i On skid equipment, except Glycol Contactor; shipped separately);
ii On skid piping plus connections brought to skid perimeter;

iii Instrumentation.

The package does not include:

i Foundations;
ii Off-skid piping;
iii PLC/DCS;
iv Electrical;
v Spare Parts;
vi Fireproofing or Firewater systems.

Overall Dehydration package cost and utilities consumptions were estimated based on Inlet volumetric flow.

5. Pipelines

Installed capital costs were estimated based on in-house $ per diameter-inch-kilometer factors. These costs were developed in matrix form to be used along with typical flow rates associated with those pipeline diameters based on an average 1 Km length of pipeline for gathering and distribution lines.

The high pressure rated CO_2 distribution pipelines (900#) design basis considered:

Material API5L-X65;
Buried 2.5 m;
Externally coated and cathodic protected.

6. Operating Costs

Operating costs were assessed using the following parameters and assumptions:

Natural Gas purchase price =	$7.00/mcf nominal;
1 MCF =	1,000,000 BTU;
Power cost:	$80 per MWH nominal;
Water cost:	N.A.;
TEG cost:	CAD 12.50 /USG;
Service factor assumption:	97%;
Other annual cash variable and	
Fixed operating costs:	3% of Total Installed Cost (TIC) of facilities.
<u>Subtotal all cash costs</u>	
Operating manpower:	10% of cash costs
<u>Total cash operating costs</u>	

Parasitic CO_2 generation from power purchase: 1 tonne per MWh power purchased (nominally an average for all sources in AB; close to that for conventional coal-fired power generation).

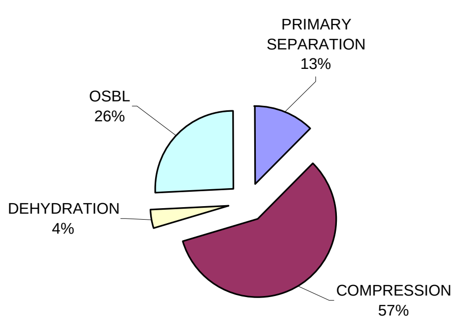
Appendix 4
Cost Estimate Detail

EQUIPMENT FACTORED ESTIMATE (+ / - 40%)

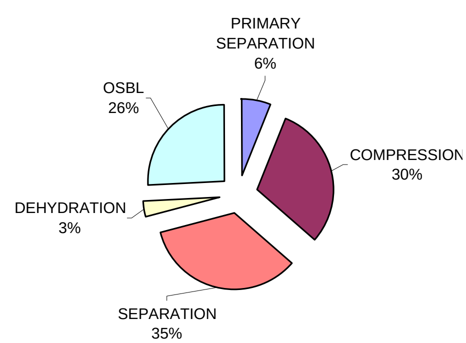
BASED ON USGC - 1ST QUARTER 2008

CASE		1-No CO2 Separation		2- CO2 Separation
UNIT	Trains		Trains	
PRIMARY SEPARATION	1	$ 17,770,000	1	$ 17,770,000
PRODUCED GAS LOW PRESSURE COMPRESSION	2	$ 19,710,000	2	$ 19,710,000
PRODUCED GAS HIGH PRESSURE COMPRESSION	2	$ 61,630,000		$ -
DEHYDRATION	2	$ 5,380,000	2	$ 9,330,000
CO_2 SEPARATION		$ -	2	$ 48,490,000
CO_2 COMPRESSION		$ -	2	$ 68,440,000
RECYCLE COMPRESSION		$ -	2	$ 32,360,000
REFRIGERATION		$ -	2	$ 19,830,000
		$ 104,490,000		**$ 215,930,000**
OSBL (ALLOWANCE OF 35% OF TOTAL COST)		$ 36,570,000		$ 75,580,000
OTHER COST		$ -		$ -
OTHER COST		$ -		$ -
ESTIMATE TIC		**$ 141,060,000**		**$ 291,510,000**

CASE 1: NO CO_2 SEPARATION



CASE 2: CO_2 SEPARATION



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AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Rev. E/MAR.31.2008

CASE #1 NO CO2 SEPARATION

PRIMARY SEPARATION

UNIT	EQUIPMENT	Percent	CAD $
2	V-001 A/B		$ 2,710,000
1	V-002		$ 125,000
1	V-003		$ 135,000
1	V-004		$ 515,000
1	EA-001	Air	$ 310,000
1	EA-002	Air	$ 150,000
1	P-001		$ 25,000
1	P-002		$ 230,000
9	**Total Equipment Cost**	**100%**	**$ 4,200,000**
	Civil	10%	$ 420,000
	Structural	8%	$ 336,000
	Buildings	3%	$ 126,000
	Piping	30%	$ 1,260,000
	Electrical	11%	$ 462,000
	Instruments	10%	$ 420,000
	Insulation	8%	$ 336,000
	Painting	2%	$ 84,000
	Fireproofing	3%	$ 126,000
	Other misc.	5%	$ 210,000
	Total Bulks Cost	**90%**	**$ 3,780,000**
	All-in Direct Labor	**96%**	**$ 4,032,000**
	S/T Direct Cost	**286%**	**$ 12,012,000**
	Const. Mangmt	8%	$ 960,960
	HO Engr/Mangmt	15%	$ 1,801,800
	Freight	15%	$ 1,197,000
	Vendor Rep/Spare Parts	3%	$ 360,360
	Comm. / Start-up	2%	$ 240,240
	Others Misc	10%	$ 1,201,200
	Sub Total		**$ 5,761,560**
	Estimated TIC Cost	**423%**	**$ 17,773,560**
	Number of Trains		**1**
	Estimated Total		**$ 17,770,000**

PRODUCED GAS LOW PRESSURE COMPRESSION

UNIT	EQUIPMENT	Percent	CAD $
2	V-005 A		$ 90,000
2	V-005 B		$ 95,000
2	V-005 C		$ 140,000
1	EA-003A		$ 80,000
1	EA-003B		$ 85,000
1	K-001A/B (2 stage)	B/Q	$ 1,822,000
9	**Total Equipment Cost**	**100%**	**$ 2,312,000**
	Civil	10%	$ 231,200
	Structural	8%	$ 184,960
	Buildings	3%	$ 69,360
	Piping	32%	$ 739,840
	Electrical	11%	$ 254,320
	Instruments	10%	$ 231,200
	Insulation	8%	$ 184,960
	Painting	2%	$ 46,240
	Fireproofing	3%	$ 69,360
	Other misc.	5%	$ 115,600
	Total Bulks Cost	**92%**	**$ 2,127,040**
	All-in Direct Labor	**96%**	**$ 2,219,520**
	S/T Direct Cost	**288%**	**$ 6,658,560**
	Const. Mangmt	8%	$ 532,685
	HO Engr/Mangmt	15%	$ 998,784
	Freight	15%	$ 665,856
	Vendor Rep/Spare Parts	3%	$ 199,757
	Comm. / Start-up	2%	$ 133,171
	Others Misc	10%	$ 665,856
	Sub Total		**$ 3,196,109**
	Estimated TIC Cost	**426%**	**$ 9,854,669**
	Number of Trains		**2**
	Estimated Total		**$ 19,710,000**

PRODUCED GAS HIGH PRESSURE COMPRESSION

UNIT	EQUIPMENT	Percent	CAD $
1	V-006		$ 12,000
1	EA-004A		$ 330,000
1	EA-004B		$ 220,000
1	K-002A/B (2 stage)		$ 6,411,000
1	Cooling Console		$ 180,000
			$ -
5	**Total Equipment Cost**	**100%**	**$ 7,153,000**
	Civil	10%	$ 715,300
	Structural	8%	$ 572,240
	Buildings	4%	$ 286,120
	Piping	34%	$ 2,432,020
	Electrical	11%	$ 786,830
	Instruments	10%	$ 715,300
	Insulation	8%	$ 572,240
	Painting	2%	$ 143,060
	Fireproofing	3%	$ 214,590
	Other misc.	5%	$ 357,650
	Total Bulks Cost	**95%**	**$ 6,795,350**
	All-in Direct Labor	**96%**	**$ 6,866,880**
	S/T Direct Cost	**291%**	**$ 20,815,230**
	Const. Mangmt	8%	$ 1,665,218
	HO Engr/Mangmt	15%	$ 3,122,285
	Freight	15%	$ 2,092,253
	Vendor Rep/Spare Parts	3%	$ 624,457
	Comm. / Start-up	2%	$ 416,305
	Others Misc	10%	$ 2,081,523
	Sub Total		**$ 10,002,040**
	Estimated TIC Cost	**431%**	**$ 30,817,270**
	Number of Trains		**2**
	Estimated Total		**$ 61,630,000**

DEHYDRATION

UNIT	EQUIPMENT	Percent	CAD $
1	PK-001		$ 760,000
			$ -
			$ -
			$ -
			$ -
			$ -
1	**Total Equipment Cost**	**100%**	**$ 760,000**
	Civil	8%	$ 60,800
	Structural	7%	$ 53,200
	Buildings	0%	$ -
	Piping	25%	$ 190,000
	Electrical	8%	$ 60,800
	Instruments	9%	$ 68,400
	Insulation	4%	$ 30,400
	Painting	2%	$ 15,200
	Fireproofing	3%	$ 22,800
	Other misc.	2%	$ 15,200
	Total Bulks Cost	**68%**	**$ 516,800**
	All-in Direct Labor	**85%**	**$ 646,000**
	S/T Direct Cost	**253%**	**$ 1,922,800**
	Const. Mangmt	7%	$ 134,596
	HO Engr/Mangmt	10%	$ 192,280
	Freight	12%	$ 153,216
	Vendor Rep/Spare Parts	3%	$ 57,684
	Comm. / Start-up	2%	$ 38,456
	Others Misc	10%	$ 192,280
	Sub Total		**$ 768,512**
	Estimated TIC Cost	**354%**	**$ 2,691,312**
	Number of Trains		**2**
	Estimated Total		**$ 5,380,000**

Total **$ 104,490,000**

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
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CASE #2 CO2 SEPARATION

UNIT

PRIMARY SEPARATION

EQUIPMENT	Percent	CAD $
2 V-001 A/B		$ 2,710,000
1 V-002		$ 125,000
1 V-003		$ 135,000
1 V-004		$ 515,000
1 EA-001	Air	$ 310,000
1 EA-002	Air	$ 150,000
1 P-001		$ 25,000
1 P-002		$ 230,000
9 Total Equipment Cost	**100%**	**$ 4,200,000**
Civil	10%	$ 420,000
Structural	8%	$ 336,000
Buildings	3%	$ 126,000
Piping	30%	$ 1,260,000
Electrical	11%	$ 462,000
Instruments	10%	$ 420,000
Insulation	8%	$ 336,000
Painting	2%	$ 84,000
Fireproofing	3%	$ 126,000
Other misc.	5%	$ 210,000
Total Bulks Cost	**90%**	**$ 3,780,000**
All-in Direct Labor	**96%**	**$ 4,032,000**
S/T Direct Cost	**286%**	**$12,012,000**
Const. Mangmt	8%	$ 960,960
HO Engr/Mangmt	15%	$ 1,801,800
Freight	15%	$ 1,197,000
Vendor Rep/Spare Parts	3%	$ 360,360
Comm. / Start-up	2%	$ 240,240
Others Misc	10%	$ 1,201,200
Sub Total		**$ 5,761,560**
Estimated TIC Cost	**423%**	**$17,773,560**
Number of Trains		**1**
Estimated Total		**$17,770,000**

PRODUCED GAS LOW PRESSURE COMPRESSION

EQUIPMENT	Percent	CAD $
2 V-005 A		$ 90,000
2 V-005 B		$ 95,000
2 V-005 C		$ 140,000
1 EA-003A		$ 80,000
1 EA-003B		$ 85,000
1 K-001A/B (2 stage)	B/Q	$ 1,822,000
9 Total Equipment Cost	**100%**	**$ 2,312,000**
Civil	10%	$ 231,200
Structural	8%	$ 184,960
Buildings	3%	$ 69,360
Piping	32%	$ 739,840
Electrical	11%	$ 254,320
Instruments	10%	$ 231,200
Insulation	8%	$ 184,960
Painting	2%	$ 46,240
Fireproofing	3%	$ 69,360
Other misc.	5%	$ 115,600
Total Bulks Cost	**92%**	**$ 2,127,040**
All-in Direct Labor	**96%**	**$ 2,219,520**
S/T Direct Cost	**288%**	**$ 6,658,560**
Const. Mangmt	8%	$ 532,685
HO Engr/Mangmt	15%	$ 998,784
Freight	15%	$ 665,856
Vendor Rep/Spare Parts	3%	$ 199,757
Comm. / Start-up	2%	$ 133,171
Others Misc	10%	$ 665,856
Sub Total		**$ 3,196,109**
Estimated TIC Cost	**426%**	**$ 9,854,669**
Number of Trains		**2**
Estimated Total		**$ 19,710,000**

PRODUCED GAS DEHYRRATION

EQUIPMENT	Percent	CAD $
1 PK-001		$ 1,318,000
1 Total Equipment Cost	**100%**	**$ 1,318,000**
Civil	8%	$ 105,440
Structural	7%	$ 92,260
Buildings	0%	$ -
Piping	25%	$ 329,500
Electrical	8%	$ 105,440
Instruments	9%	$ 118,620
Insulation	4%	$ 52,720
Painting	2%	$ 26,360
Fireproofing	3%	$ 39,540
Other misc.	2%	$ 26,360
Total Bulks Cost	**68%**	**$ 896,240**
All-in Direct Labor	**85%**	**$ 1,120,300**
S/T Direct Cost	**253%**	**$ 3,334,540**
Const. Mangmt	7%	$ 233,418
HO Engr/Mangmt	10%	$ 333,454
Freight	12%	$ 265,709
Vendor Rep/Spare Parts	3%	$ 100,036
Comm. / Start-up	2%	$ 66,691
Others Misc	10%	$ 333,454
Sub Total		**$ 1,332,762**
Estimated TIC Cost	**354%**	**$ 4,667,302**
Number of Trains		**2**
Estimated Total		**$ 9,330,000**

CO2 SEPARATION

EQUIPMENT	Percent	CAD $
1 E-001		$ 40,000
1 E-002		$ 26,000
1 V-006		$ 135,000
1 V-007		$ 145,000
1 PK-002		$ 6,500,000
5 Total Equipment Cost	**100%**	**$ 6,846,000**
Civil	8%	$ 547,680
Structural	7%	$ 479,220
Buildings	0%	$ -
Piping	25%	$ 1,711,500
Electrical	8%	$ 547,680
Instruments	9%	$ 616,140
Insulation	4%	$ 273,840
Painting	2%	$ 136,920
Fireproofing	3%	$ 205,380
Other misc.	2%	$ 136,920
Total Bulks Cost	**68%**	**$ 4,655,280**
All-in Direct Labor	**85%**	**$ 5,819,100**
S/T Direct Cost	**253%**	**$ 17,320,380**
Const. Mangmt	7%	$ 1,212,427
HO Engr/Mangmt	10%	$ 1,732,038
Freight	12%	$ 1,380,154
Vendor Rep/Spare Parts	3%	$ 519,611
Comm. / Start-up	2%	$ 346,408
Others Misc	10%	$ 1,732,038
Sub Total		**$ 6,922,675**
Estimated TIC Cost	**354%**	**$ 24,243,055**
Number of Trains		**2**
Estimated Total		**$ 48,490,000**

CO2 COMPRESSION

EQUIPMENT	Percent	CAD $
		$ -
1 V-008A		$ 140,000
1 V-008B		$ 132,000
1 V-008C		$ 126,000
1 EA-004A		$ 485,000
1 EA-004B		$ 490,000
1 EA-004C		$ 440,000
1 K-002A,B,C (3 stage)	B/Q	$ 6,061,000
1 Cooling Console		$ 180,000
		$ -
8 Total Equipment Cost	**100%**	**$ 8,054,000**
Civil	10%	$ 805,400
Structural	8%	$ 644,320
Buildings	4%	$ 322,160
Piping	32%	$ 2,577,280
Electrical	11%	$ 885,940
Instruments	10%	$ 805,400
Insulation	8%	$ 644,320
Painting	2%	$ 161,080
Fireproofing	3%	$ 241,620
Other misc.	5%	$ 402,700
Total Bulks Cost	**93%**	**$ 7,490,220**
All-in Direct Labor	**96%**	**$ 7,731,840**
S/T Direct Cost	**289%**	**$ 23,276,060**
Const. Mangmt	7%	$ 1,629,324
HO Engr/Mangmt	15%	$ 3,491,409
Freight	15%	$ 2,331,633
Vendor Rep/Spare Parts	3%	$ 698,282
Comm. / Start-up	2%	$ 465,521
Others Misc	10%	$ 2,327,606
Sub Total		**$ 10,943,775**
Estimated TIC Cost	**425%**	**$ 34,219,835**
Number of Trains		**2**
Estimated Total		**$ 68,440,000**

RECYCLE COMPRESSION

EQUIPMENT	Percent	CAD $
1 V-010A		$ 139,000
1 V-010B		$ 128,000
1 V-010C		$ 100,000
1 V-011		$ 95,000
1 EA-006A		$ 125,000
1 EA-006B		$ 123,000
1 K-004A,B (2 stage)		$ 3,289,000
7 Total Equipment Cost	**100%**	**$ 3,999,000**
Civil	10%	$ 399,900
Structural	8%	$ 319,920
Buildings	4%	$ 159,960
Piping	32%	$ 1,279,680
Electrical	11%	$ 439,890
Instruments	10%	$ 399,900
Insulation	8%	$ 319,920
Painting	2%	$ 79,980
Fireproofing	3%	$ 119,970
Other misc.	5%	$ 199,950
Total Bulks Cost	**93%**	**$ 3,719,070**
All-in Direct Labor	**96%**	**$ 3,839,040**
S/T Direct Cost	**289%**	**$ 11,557,110**
Const. Mangmt	7%	$ 808,998
HO Engr/Mangmt	10%	$ 1,155,711
Freight	12%	$ 926,168
Vendor Rep/Spare Parts	3%	$ 346,713
Comm. / Start-up	2%	$ 231,142
Others Misc	10%	$ 1,155,711
Sub Total		**$ 4,624,444**
Estimated TIC Cost	**405%**	**$ 16,181,554**
Number of Trains		**2**
Estimated Total		**$ 32,360,000**

REFRIGERATION

EQUIPMENT	Percent	CAD $
1 PK-003		$ 2,800,000
		$ -
		$ -
		$ -
		$ -
		$ -
1 Total Equipment Cost	**100%**	**$ 2,800,000**
Civil	8%	$ 224,000
Structural	7%	$ 196,000
Buildings	0%	$ -
Piping	25%	$ 700,000
Electrical	8%	$ 224,000
Instruments	9%	$ 252,000
Insulation	4%	$ 112,000
Painting	2%	$ 56,000
Fireproofing	3%	$ 84,000
Other misc.	2%	$ 56,000
Total Bulks Cost	**68%**	**$ 1,904,000**
All-in Direct Labor	**85%**	**$ 2,380,000**
S/T Direct Cost	**253%**	**$ 7,084,000**
Const. Mangmt	7%	$ 495,880
HO Engr/Mangmt	10%	$ 708,400
Freight	12%	$ 564,480
Vendor Rep/Spare Parts	3%	$ 212,520
Comm. / Start-up	2%	$ 141,680
Others Misc	10%	$ 708,400
Sub Total		**$ 2,831,360**
Estimated TIC Cost	**354%**	**$ 9,915,360**
Number of Trains		**2**
Estimated Total		**$ 19,830,000**

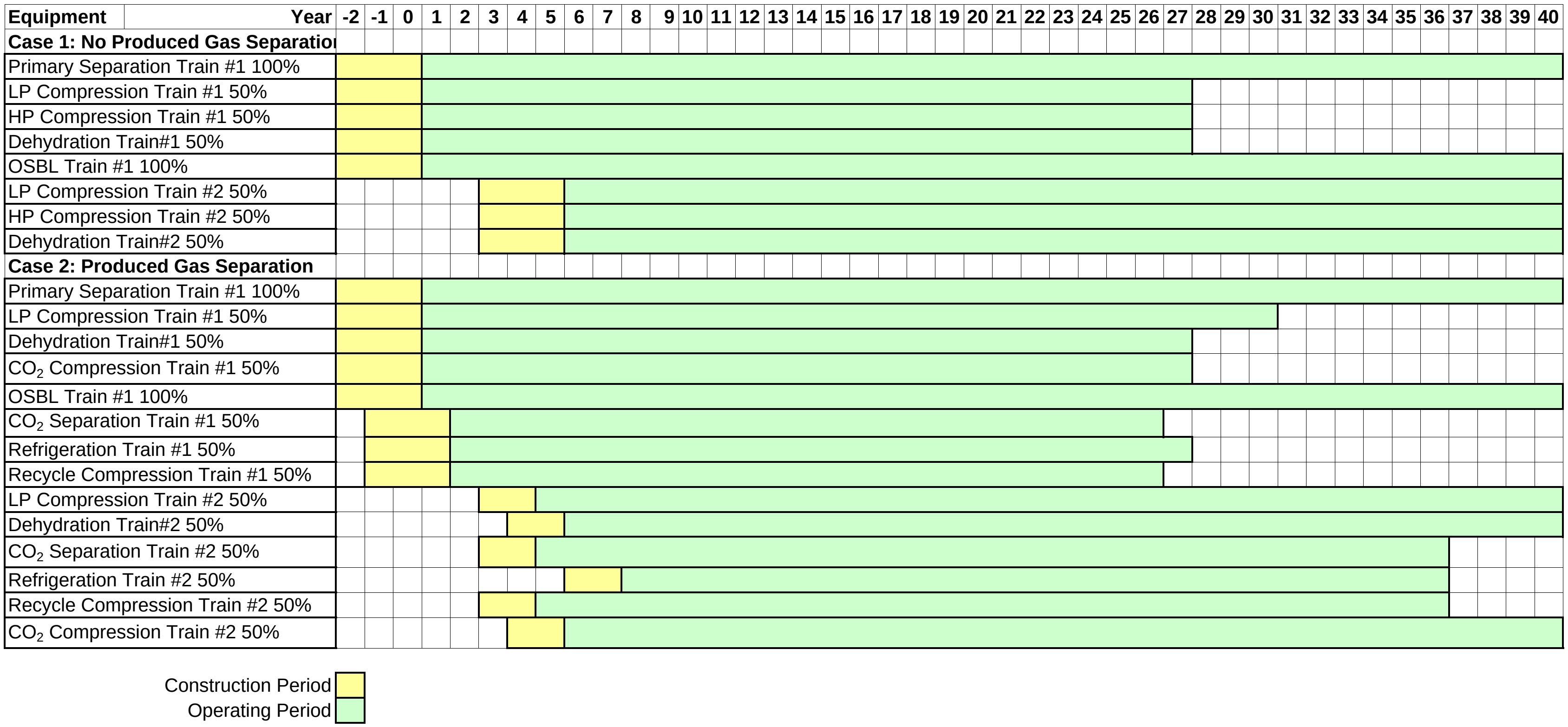
Total **$ 215,930,000**

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY

PROJECT # : 017935

Equipment Construction/Operating Periods

Rev. A/MAR.31.2008



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AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Operating Costs Calculations
Rev. E/MAR.31.2008

CASE #1 NO CO2 SEPARATION

WELLS PRODUCTION FORECAST

Year	OIL Sm^3/h	PROD. WATER Sm^3/h	PROD. CO_2 kg/h	PROD. CO_2 Sm^3/h	ASSOCIATED GAS Sm^3/h	TOTAL PROD.GAS Sm^3/h
1	10.35	332	9071	4874	2584	7458
2	27.32	406	35136	18879	6284	25163
3	37.47	494	60660	32592	8198	40791
4	50.54	594	77512	41647	11044	52691
5	56.36	676	101740	54665	12016	66681
6	55.77	771	117325	63039	11775	74814
7	55.41	850	124438	66860	12258	79119
8	54.40	915	142515	76573	12353	88926
9	52.66	962	153409	82427	12482	94908
10	51.01	967	164453	88361	12607	100967
11	49.68	1009	177845	95556	12478	108034
12	50.36	1055	190335	102267	13239	115506
13	48.13	1071	200025	107473	12959	120433
14	52.59	1107	206122	110749	13764	124513
15	54.27	1163	209901	112780	13481	126261
16	58.07	1219	218752	117535	13825	131360
17	60.18	1299	218618	117463	14255	131718
18	64.33	1366	220044	118230	14763	132993
19	66.47	1349	223694	120191	14492	134683
20	61.42	1313	220228	118329	13030	131359
21	56.33	1192	214084	115027	11704	126731
22	51.73	1172	201866	108463	10599	119061
23	46.87	1143	187620	100808	9472	110280
24	42.63	1126	167502	89999	8510	98509
25	37.69	1091	147573	79291	7501	86792
26	34.05	1071	134377	72201	6759	78960
27	30.19	1033	119868	64405	5973	70378
28	26.63	983	106339	57136	5264	62399
29	23.44	931	91671	49255	4652	53907
30	20.52	899	75553	40595	4054	44648
31	16.33	680	59190	31803	3196	34999
32	14.02	608	49999	26865	2752	29617
33	12.07	590	41690	22400	2374	24774
34	9.86	517	33465	17981	1947	19928
35	7.96	434	26682	14336	1597	15934
36	6.64	390	22296	11980	1355	13334
37	5.02	303	16761	9006	1011	10017
38	3.36	187	10905	5859	676	6535
39	2.68	159	7652	4111	553	4664
40	2.37	154	5650	3036	494	3530

SEPARATION PLANT PRODUCTION FORECAST

Year	TOTAL WELL PROD. Sm^3/h	TOTAL WELL PROD. kg/h	PROD. OIL Sm^3/h	PROD. OIL kg/h	PROD. WATER Sm^3/h	PROD. WATER kg/h	WASTE WATER Sm^3/h	WASTE WATER kg/h	PROD. GAS REINJECTED kg/h	PROD. GAS REINJECTED vol.% CO_2	PROD. GAS REINJECTED wt. % CO_2
1	7,800	351,721	10.5	8,489	333	332,048	0.125	122	11,049	63.53%	74.53%
2	25,596	469,596	27.6	22,322	407	405,983	0.211	205	41,039	74.52%	82.87%
3	41,323	593,350	37.6	30,509	495	493,944	0.277	271	68,551	79.52%	86.42%
4	53,335	723,828	50.8	41,192	595	593,928	0.334	325	88,285	78.68%	85.83%
5	67,413	835,718	56.5	45,814	678	675,895	0.392	383	113,524	81.62%	87.88%
6	75,641	945,362	55.7	45,210	773	770,873	0.455	445	128,719	83.89%	89.43%
7	80,024	1,031,562	55.3	44,873	852	849,866	0.499	489	136,213	84.13%	89.59%
8	89,896	1,113,791	54.1	43,938	917	914,842	0.544	533	154,341	85.74%	90.67%
9	95,923	1,170,317	52.3	42,454	964	961,829	0.574	563	165,325	86.49%	91.17%
10	101,985	1,185,146	50.5	41,054	969	966,817	0.579	569	176,551	87.17%	91.63%
11	109,093	1,239,226	49.1	39,901	1,011	1,008,800	0.609	598	189,760	88.11%	92.26%
12	116,612	1,299,027	49.7	40,412	1,057	1,054,788	0.635	624	203,025	88.20%	92.32%
13	121,552	1,322,555	47.4	38,548	1,074	1,070,776	0.648	637	212,408	88.91%	92.79%
14	125,673	1,369,112	51.9	42,170	1,110	1,106,770	0.669	658	219,323	88.62%	92.59%
15	127,478	1,429,831	53.5	43,512	1,166	1,162,761	0.707	695	222,668	88.99%	92.83%
16	132,638	1,498,050	57.3	46,576	1,222	1,218,749	0.744	731	231,793	89.14%	92.93%
17	133,078	1,579,954	59.4	48,293	1,302	1,298,747	0.791	777	231,935	88.83%	92.73%
18	134,423	1,652,194	63.6	51,675	1,369	1,365,743	0.831	816	233,755	88.55%	92.53%
19	136,098	1,639,829	65.7	53,395	1,352	1,348,278	0.825	810	237,138	88.91%	92.77%
20	132,733	1,595,178	60.6	49,274	1,316	1,312,737	0.810	796	232,170	89.74%	93.31%
21	127,980	1,462,650	55.5	45,141	1,195	1,191,745	0.740	727	224,843	90.43%	93.76%
22	120,285	1,425,490	50.9	41,420	1,175	1,171,755	0.730	718	211,415	90.76%	93.97%
23	111,470	1,377,085	46.1	37,496	1,146	1,142,767	0.714	702	195,949	91.07%	94.17%
24	99,677	1,335,472	41.9	34,101	1,129	1,125,786	0.703	692	174,742	91.01%	94.13%
25	87,920	1,275,461	37.1	30,136	1,094	1,090,805	0.682	671	153,716	90.99%	94.12%
26	80,065	1,238,511	33.5	27,209	1,074	1,070,818	0.669	659	139,705	91.06%	94.17%
27	71,442	1,182,056	29.6	24,109	1,035	1,032,832	0.646	636	124,371	91.13%	94.21%
28	63,409	1,114,935	26.1	21,254	985	982,847	0.615	606	110,134	91.17%	94.23%
29	54,862	1,045,090	23.0	18,706	933	930,864	0.581	572	94,865	90.95%	94.10%
30	45,568	993,989	20.1	16,383	901	898,883	0.557	548	78,106	90.46%	93.78%
31	35,696	754,695	16.0	13,046	682	679,910	0.421	415	61,271	90.42%	93.75%
32	30,239	671,271	13.8	11,201	609	607,923	0.375	370	51,732	90.24%	93.64%
33	25,376	642,987	11.9	9,640	591	589,933	0.362	356	43,020	89.91%	93.42%
34	20,455	559,632	9.7	7,874	518	516,946	0.315	311	34,472	89.69%	93.29%
35	16,376	468,077	7.8	6,356	435	433,957	0.263	259	27,480	89.42%	93.11%
36	13,731	418,434	6.5	5,299	391	389,964	0.235	232	22,919	89.25%	93.01%
37	10,325	324,370	4.9	4,005	304	302,972	0.183	180	17,197	89.31%	93.04%
38	6,726	201,021	3.3	2,684	187	186,983	0.113	111	11,233	89.07%	92.89%
39	4,826	169,133	2.6	2,146	159	158,989	0.093	91	7,899	87.43%	91.82%
40	3,686	161,823	2.3	1,903	154	153,996	0.085	84	5,835	85.06%	90.27%

 # Trains / UTILITIES CONSUMPTION ESTIMATE / PARASITIC CO_2 CALCULATION

Year	# Trains: PRIMARY SEP.	# Trains: COMP. + DEHY.	POWER kWh/h	NATURAL GAS Sm^3/h	CHEMICALS (TEG) kg/h	POWER PARASITIC CO_2 to/h	VENT PARASITIC CO_2 to/h	TOTAL to/h	TOTAL to/year	% of CO_2 REINJECTED
1	1	1	1,293	7.0	0.3	1.29	0.014	1.31	10,870	15.86%
2	1	1	2,350	13.1	1.2	2.35	0.025	2.38	19,768	6.98%
3	1	1	3,320	18.7	2.0	3.32	0.036	3.36	27,930	5.67%
4	1	1	4,016	22.7	2.6	4.02	0.044	4.06	33,785	5.36%
5	1	1	4,906	27.8	3.4	4.91	0.053	4.96	41,273	4.97%
6	1	2	6,279	35.7	7.6	6.28	0.069	6.35	52,824	5.51%
7	1	2	6,543	37.2	8.0	6.54	0.071	6.61	55,047	5.42%
8	1	2	7,182	40.8	9.1	7.18	0.079	7.26	60,426	5.19%
9	1	2	7,570	43.1	9.8	7.57	0.083	7.65	63,684	5.08%
10	1	2	7,966	45.3	10.4	7.97	0.087	8.05	67,015	4.98%
11	1	2	8,431	48.0	11.2	8.43	0.092	8.52	70,934	4.87%
12	1	2	8,899	50.7	12.0	8.90	0.098	9.00	74,870	4.80%
13	1	2	9,230	52.6	12.5	9.23	0.101	9.33	77,654	4.73%
14	1	2	9,474	54.0	12.9	9.47	0.104	9.58	79,705	4.72%
15	1	2	9,592	54.7	13.1	9.59	0.105	9.70	80,698	4.69%
16	1	2	9,913	56.5	13.7	9.91	0.109	10.02	83,405	4.65%
17	1	2	9,919	56.5	13.7	9.92	0.109	10.03	83,447	4.66%
18	1	2	9,983	56.9	13.8	9.98	0.109	10.09	83,987	4.67%
19	1	2	10,102	57.6	14.0	10.10	0.111	10.21	84,991	4.64%
20	1	2	9,927	56.6	13.7	9.93	0.109	10.04	83,517	4.63%
21	1	2	9,668	55.1	13.3	9.67	0.106	9.77	81,343	4.64%
22	1	2	9,195	52.4	12.5	9.19	0.101	9.30	77,359	4.68%
23	1	2	8,650	49.3	11.6	8.65	0.095	8.74	72,770	4.74%
24	1	2	7,902	45.0	10.3	7.90	0.086	7.99	66,478	4.86%
25	1	2	7,160	40.7	9.1	7.16	0.078	7.24	60,240	5.00%
26	1	2	6,666	37.9	8.2	6.67	0.073	6.74	56,083	5.12%
27	1	2	6,126	34.8	7.3	6.13	0.067	6.19	51,534	5.29%
28	1	1	4,787	27.1	3.3	4.79	0.052	4.84	40,267	4.66%
29	1	1	4,248	24.0	2.8	4.25	0.046	4.29	35,737	4.81%
30	1	1	3,657	20.6	2.3	3.66	0.040	3.70	30,765	5.05%
31	1	1	3,064	17.2	1.8	3.06	0.033	3.10	25,770	5.39%
32	1	1	2,727	15.3	1.5	2.73	0.029	2.76	22,940	5.69%
33	1	1	2,420	13.5	1.3	2.42	0.026	2.45	20,355	6.09%
34	1	1	2,119	11.8	1.0	2.12	0.023	2.14	17,819	6.66%
35	1	1	1,872	10.4	0.8	1.87	0.020	1.89	15,745	7.39%
36	1	1	1,711	9.4	0.7	1.71	0.018	1.73	14,391	8.11%
37	1	1	1,509	8.3	0.5	1.51	0.016	1.53	12,694	9.53%
38	1	1	1,299	7.1	0.3	1.30	0.014	1.31	10,924	12.58%
39	1	1	1,182	6.4	0.2	1.18	0.012	1.19	9,935	16.46%
40	1	1	1,109	6.0	0.2	1.11	0.012	1.12	9,323	21.27%

Power Specific Consuptions		
Prim. Sep.	0.0004041	kW/Sm^3 inlet
Comp. Dehy	0.0352621	kW/kg outlet

Nat. Gas. Specific Consumption
0.0002024 Sm3/kg

TEG Specific Consumption
2.952E-05 kg/kg

SPECIFIC POWER PARASITIC CO_2	1	kg/kWh
DEHY. REBOILER FLUE GAS CO2 CONC	13.6%	wt.

SEE NEXT PAGE FOR REST OF THE TABLE

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY

SNC·LAVALIN

PROJECT # : 017935

Operating Costs Calculations

Rev. E/MAR.31.2008

CASE #1 NO CO2 SEPARATION

Year	GAS REINJECTED to/year	GAS REINJECTED wt. % CO2	CO2 REINJECTED to/year	UTILITIES COSTS: Power kW/to	Power $/to	Power $/year	Natural Gas Sm^3/to	Natural Gas $/to	Natural Gas $/year
1	91,947	74.53%	68,529	117	$9.36	$860,561	0.637	$0.157	$14,475
2	341,528	82.87%	283,023	57	$4.58	$1,564,622	0.319	$0.079	$26,964
3	570,484	86.42%	493,028	48	$3.87	$2,210,499	0.272	$0.067	$38,420
4	734,710	85.83%	630,629	45	$3.64	$2,673,777	0.257	$0.063	$46,638
5	944,744	87.88%	830,200	43	$3.46	$3,266,274	0.245	$0.060	$57,147
6	1,071,202	89.43%	957,926	49	$3.90	$4,180,251	0.277	$0.068	$73,349
7	1,133,564	89.59%	1,015,546	48	$3.84	$4,356,173	0.273	$0.067	$76,470
8	1,284,430	90.67%	1,164,644	47	$3.72	$4,781,760	0.265	$0.065	$84,019
9	1,375,833	91.17%	1,254,410	46	$3.66	$5,039,606	0.260	$0.064	$88,592
10	1,469,255	91.63%	1,346,257	45	$3.61	$5,303,145	0.257	$0.063	$93,267
11	1,579,187	92.26%	1,456,881	44	$3.55	$5,613,260	0.253	$0.063	$98,767
12	1,689,577	92.32%	1,559,839	44	$3.51	$5,924,667	0.250	$0.062	$104,291
13	1,767,662	92.79%	1,640,238	43	$3.48	$6,144,944	0.248	$0.061	$108,198
14	1,825,206	92.59%	1,690,015	43	$3.46	$6,307,272	0.246	$0.061	$111,078
15	1,853,047	92.83%	1,720,240	43	$3.45	$6,385,811	0.246	$0.061	$112,471
16	1,928,978	92.93%	1,792,554	43	$3.42	$6,600,009	0.244	$0.060	$116,270
17	1,930,159	92.73%	1,789,747	43	$3.42	$6,603,342	0.244	$0.060	$116,329
18	1,945,309	92.53%	1,800,067	43	$3.42	$6,646,080	0.243	$0.060	$117,087
19	1,973,465	92.77%	1,830,770	43	$3.41	$6,725,508	0.243	$0.060	$118,496
20	1,932,117	93.31%	1,802,765	43	$3.42	$6,608,865	0.244	$0.060	$116,427
21	1,871,139	93.76%	1,754,309	43	$3.44	$6,436,849	0.245	$0.061	$113,376
22	1,759,397	93.97%	1,653,301	43	$3.48	$6,121,628	0.248	$0.061	$107,785
23	1,630,691	94.17%	1,535,617	44	$3.53	$5,758,552	0.251	$0.062	$101,345
24	1,454,203	94.13%	1,368,818	45	$3.62	$5,260,685	0.257	$0.064	$92,514
25	1,279,225	94.12%	1,203,987	47	$3.73	$4,767,077	0.265	$0.065	$83,758
26	1,162,624	94.17%	1,094,799	48	$3.82	$4,438,148	0.271	$0.067	$77,924
27	1,035,014	94.21%	975,058	49	$3.94	$4,078,166	0.280	$0.069	$71,539
28	916,536	94.23%	863,693	43	$3.48	$3,186,701	0.246	$0.061	$55,736
29	789,467	94.10%	742,875	45	$3.58	$2,828,245	0.253	$0.063	$49,377
30	650,000	93.78%	609,586	47	$3.75	$2,434,811	0.264	$0.065	$42,399
31	509,896	93.75%	478,033	50	$4.00	$2,039,582	0.281	$0.069	$35,388
32	430,515	93.64%	403,127	53	$4.22	$1,815,651	0.295	$0.073	$31,416
33	358,009	93.42%	334,468	56	$4.50	$1,611,113	0.314	$0.078	$27,788
34	286,873	93.29%	267,612	61	$4.92	$1,410,441	0.342	$0.084	$24,229
35	228,691	93.11%	212,934	68	$5.45	$1,246,311	0.377	$0.093	$21,318
36	190,732	93.01%	177,391	75	$5.97	$1,139,230	0.412	$0.102	$19,418
37	143,113	93.04%	133,157	88	$7.02	$1,004,899	0.482	$0.119	$17,036
38	93,482	92.89%	86,831	116	$9.25	$864,890	0.630	$0.156	$14,552
39	65,739	91.82%	60,364	150	$11.97	$786,628	0.810	$0.200	$13,164
40	48,557	90.27%	43,831	190	$15.20	$738,160	1.025	$0.253	$12,304
	42,346,308		39,127,100						

Year	TEG kg/to	TEG $/to	TEG $/year	Total Utilities $/to	Total Utilities $/year	Other variable Costs (maintenance + others) 3% of Capex $/to	Other variable Costs $/year	Subtotal $/to	Subtotal $/year	Manpower Add-in 10% of Subtotal $/to	Manpower Add-in $/year
1	0.030	$0.010	$903	$9.53	$875,940	$31.88	$2,931,000	$41.40	$3,806,940	$6.81	$626,370
2	0.030	$0.010	$3,355	$4.67	$1,594,941	$8.58	$2,931,000	$13.25	$4,525,941	$1.83	$626,370
3	0.030	$0.010	$5,605	$3.95	$2,254,523	$5.14	$2,931,000	$9.09	$5,185,523	$1.10	$626,370
4	0.030	$0.010	$7,218	$3.71	$2,727,632	$3.99	$2,931,000	$7.70	$5,658,632	$0.85	$626,370
5	0.030	$0.010	$9,281	$3.53	$3,332,703	$3.10	$2,931,000	$6.63	$6,263,703	$0.66	$626,370
6	0.059	$0.020	$21,047	$3.99	$4,274,647	$3.95	$4,231,800	$7.94	$8,506,447	$1.04	$1,111,458
7	0.059	$0.020	$22,273	$3.93	$4,454,915	$3.73	$4,231,800	$7.66	$8,686,715	$0.98	$1,111,458
8	0.059	$0.020	$25,237	$3.81	$4,891,016	$3.29	$4,231,800	$7.10	$9,122,816	$0.87	$1,111,458
9	0.059	$0.020	$27,033	$3.75	$5,155,231	$3.08	$4,231,800	$6.82	$9,387,031	$0.81	$1,111,458
10	0.059	$0.020	$28,868	$3.69	$5,425,280	$2.88	$4,231,800	$6.57	$9,657,080	$0.76	$1,111,458
11	0.059	$0.020	$31,028	$3.64	$5,743,056	$2.68	$4,231,800	$6.32	$9,974,856	$0.70	$1,111,458
12	0.059	$0.020	$33,197	$3.59	$6,062,156	$2.50	$4,231,800	$6.09	$10,293,956	$0.66	$1,111,458
13	0.059	$0.020	$34,732	$3.56	$6,287,874	$2.39	$4,231,800	$5.95	$10,519,674	$0.63	$1,111,458
14	0.059	$0.020	$35,862	$3.54	$6,454,212	$2.32	$4,231,800	$5.85	$10,686,012	$0.61	$1,111,458
15	0.059	$0.020	$36,409	$3.53	$6,534,692	$2.28	$4,231,800	$5.81	$10,766,492	$0.60	$1,111,458
16	0.059	$0.020	$37,901	$3.50	$6,754,181	$2.19	$4,231,800	$5.70	$10,985,981	$0.58	$1,111,458
17	0.059	$0.020	$37,925	$3.50	$6,757,596	$2.19	$4,231,800	$5.69	$10,989,396	$0.58	$1,111,458
18	0.059	$0.020	$38,222	$3.50	$6,801,389	$2.18	$4,231,800	$5.67	$11,033,189	$0.57	$1,111,458
19	0.059	$0.020	$38,775	$3.49	$6,882,779	$2.14	$4,231,800	$5.63	$11,114,579	$0.56	$1,111,458
20	0.059	$0.020	$37,963	$3.50	$6,763,255	$2.19	$4,231,800	$5.69	$10,995,055	$0.58	$1,111,458
21	0.059	$0.020	$36,765	$3.52	$6,586,990	$2.26	$4,231,800	$5.78	$10,818,790	$0.59	$1,111,458
22	0.059	$0.020	$34,569	$3.56	$6,263,982	$2.41	$4,231,800	$5.97	$10,495,782	$0.63	$1,111,458
23	0.059	$0.020	$32,040	$3.61	$5,891,937	$2.60	$4,231,800	$6.21	$10,123,737	$0.68	$1,111,458
24	0.059	$0.020	$28,573	$3.70	$5,381,771	$2.91	$4,231,800	$6.61	$9,613,571	$0.76	$1,111,458
25	0.059	$0.020	$25,135	$3.81	$4,875,970	$3.31	$4,231,800	$7.12	$9,107,770	$0.87	$1,111,458
26	0.059	$0.020	$22,844	$3.90	$4,538,916	$3.64	$4,231,800	$7.54	$8,770,716	$0.96	$1,111,458
27	0.059	$0.020	$20,336	$4.03	$4,170,041	$4.09	$4,231,800	$8.12	$8,401,841	$1.07	$1,111,458
28	0.030	$0.010	$9,004	$3.55	$3,251,441	$3.20	$2,931,000	$6.75	$6,182,441	$0.68	$626,370
29	0.030	$0.010	$7,756	$3.65	$2,885,378	$3.71	$2,931,000	$7.37	$5,816,378	$0.79	$626,370
30	0.030	$0.010	$6,386	$3.82	$2,483,596	$4.51	$2,931,000	$8.33	$5,414,596	$0.96	$626,370
31	0.030	$0.010	$5,009	$4.08	$2,079,980	$5.75	$2,931,000	$9.83	$5,010,980	$1.23	$626,370
32	0.030	$0.010	$4,229	$4.30	$1,851,297	$6.81	$2,931,000	$11.11	$4,782,297	$1.45	$626,370
33	0.030	$0.010	$3,517	$4.59	$1,642,419	$8.19	$2,931,000	$12.77	$4,573,419	$1.75	$626,370
34	0.030	$0.010	$2,818	$5.01	$1,437,488	$10.22	$2,931,000	$15.23	$4,368,488	$2.18	$626,370
35	0.030	$0.010	$2,247	$5.55	$1,269,875	$12.82	$2,931,000	$18.37	$4,200,875	$2.74	$626,370
36	0.030	$0.010	$1,874	$6.08	$1,160,522	$15.37	$2,931,000	$21.45	$4,091,522	$3.28	$626,370
37	0.030	$0.010	$1,406	$7.15	$1,023,341	$20.48	$2,931,000	$27.63	$3,954,341	$4.38	$626,370
38	0.030	$0.010	$918	$9.42	$880,360	$31.35	$2,931,000	$40.77	$3,811,360	$6.70	$626,370
39	0.030	$0.010	$646	$12.18	$800,438	$44.59	$2,931,000	$56.76	$3,731,438	$9.53	$626,370
40	0.030	$0.010	$477	$15.47	$750,941	$60.36	$2,931,000	$75.83	$3,681,941	$12.90	$626,370

Year	TOTAL OPEX PLANT $/to	TOTAL OPEX PLANT $/year	Fixed Costs (Capital Charge) 10% of Capex $/to	Fixed Costs $/year	REINJECTED GAS UNIT COST FOB PLANT $/to	REINJECTED GAS UNIT COST OPERATING ONLY FOB PLANT $/to	REINJECTED CO_2 UNIT COST FOB PLANT $/to	REINJECTED CO_2 UNIT COST OPERATING ONLY FOB PLANT $/to
1	$48.22	$4,433,310	$106.26	$9,770,000	$154.47	$48.22	$207.26	$64.69
2	$15.09	$5,152,311	$28.61	$9,770,000	$43.69	$15.09	$52.72	$18.20
3	$10.19	$5,811,894	$17.13	$9,770,000	$27.31	$10.19	$31.60	$11.79
4	$8.55	$6,285,002	$13.30	$9,770,000	$21.85	$8.55	$25.46	$9.97
5	$7.29	$6,890,073	$10.34	$9,770,000	$17.63	$7.29	$20.07	$8.30
6	$8.98	$9,617,905	$13.17	$14,106,000	$22.15	$8.98	$24.77	$10.04
7	$8.64	$9,798,173	$12.44	$14,106,000	$21.09	$8.64	$23.54	$9.65
8	$7.97	$10,234,273	$10.98	$14,106,000	$18.95	$7.97	$20.90	$8.79
9	$7.63	$10,498,489	$10.25	$14,106,000	$17.88	$7.63	$19.61	$8.37
10	$7.33	$10,768,538	$9.60	$14,106,000	$16.93	$7.33	$18.48	$8.00
11	$7.02	$11,086,314	$8.93	$14,106,000	$15.95	$7.02	$17.29	$7.61
12	$6.75	$11,405,414	$8.35	$14,106,000	$15.10	$6.75	$16.36	$7.31
13	$6.58	$11,631,132	$7.98	$14,106,000	$14.56	$6.58	$15.69	$7.09
14	$6.46	$11,797,470	$7.73	$14,106,000	$14.19	$6.46	$15.33	$6.98
15	$6.41	$11,877,949	$7.61	$14,106,000	$14.02	$6.41	$15.10	$6.90
16	$6.27	$12,097,438	$7.31	$14,106,000	$13.58	$6.27	$14.62	$6.75
17	$6.27	$12,100,854	$7.31	$14,106,000	$13.58	$6.27	$14.64	$6.76
18	$6.24	$12,144,647	$7.25	$14,106,000	$13.49	$6.24	$14.58	$6.75
19	$6.20	$12,226,037	$7.15	$14,106,000	$13.34	$6.20	$14.38	$6.68
20	$6.27	$12,106,513	$7.30	$14,106,000	$13.57	$6.27	$14.54	$6.72
21	$6.38	$11,930,248	$7.54	$14,106,000	$13.91	$6.38	$14.84	$6.80
22	$6.60	$11,607,240	$8.02	$14,106,000	$14.61	$6.60	$15.55	$7.02
23	$6.89	$11,235,195	$8.65	$14,106,000	$15.54	$6.89	$16.50	$7.32
24	$7.38	$10,725,029	$9.70	$14,106,000	$17.08	$7.38	$18.14	$7.84
25	$7.99	$10,219,228	$11.03	$14,106,000	$19.02	$7.99	$20.20	$8.49
26	$8.50	$9,882,174	$12.13	$14,106,000	$20.63	$8.50	$21.91	$9.03
27	$9.19	$9,513,299	$13.63	$14,106,000	$22.82	$9.19	$24.22	$9.76
28	$7.43	$6,808,811	$10.66	$9,770,000	$18.09	$7.43	$19.20	$7.88
29	$8.16	$6,442,748	$12.38	$9,770,000	$20.54	$8.16	$21.82	$8.67
30	$9.29	$6,040,966	$15.03	$9,770,000	$24.32	$9.29	$25.94	$9.91
31	$11.06	$5,637,350	$19.16	$9,770,000	$30.22	$11.06	$32.23	$11.79
32	$12.56	$5,408,667	$22.69	$9,770,000	$35.26	$12.56	$37.65	$13.42
33	$14.52	$5,199,789	$27.29	$9,770,000	$41.81	$14.52	$44.76	$15.55
34	$17.41	$4,994,858	$34.06	$9,770,000	$51.47	$17.41	$55.17	$18.66
35	$21.11	$4,827,246	$42.72	$9,770,000	$63.83	$21.11	$68.55	$22.67
36	$24.74	$4,717,893	$51.22	$9,770,000	$75.96	$24.74	$81.67	$26.60
37	$32.01	$4,580,711	$68.27	$9,770,000	$100.28	$32.01	$107.77	$34.40
38	$47.47	$4,437,731	$104.51	$9,770,000	$151.98	$47.47	$163.63	$51.11
39	$66.29	$4,357,809	$148.62	$9,770,000	$214.91	$66.29	$234.04	$72.19
40	$88.73	$4,308,311	$201.21	$9,770,000	$289.93	$88.73	$321.19	$98.29
					$19.53	**$8.05**	**$21.14**	**$8.71**
					AVERAGE GAS UNIT COST		AVERAGE PURE CO_2 UNIT COST	

Service Factor	95%
Hours/Year Op.	8322

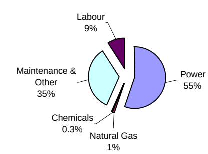
POWER COST	$80.00	$/MW
	$0.08	$/kW

NATURAL GAS COST	$7.00	$/Mf^3
	$7.00	$/28.3 m^3
	$0.25	$/m^3

TEG COST	$12.50	$/gal
	$3.30	$/l
	$3.00	$/kg

PLANT CAPEX	TOTAL	$141,060,000
	PRIMARY SEPARATION	$17,770,000
	COMP.+DEHY.	$43,360,000
	OSBL	$36,570,000

Case 1 Annual Cash OPEX Breakdown -Year 19



Case 1 Annual Cash OPEX Breakdown - Overall Project Lifetime

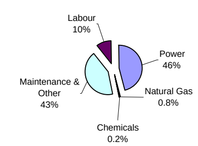


TABLE CONTINUED FROM PREVIOUS PAGE

CASE #2 CO2 SEPARATION

WELLS PRODUCTION FORECAST

Year	OIL (Sm^3/h)	PROD. WATER (Sm^3/h)	PROD. CO_2 (kg/h)	PROD. CO_2 (Sm^3/h)	ASSOCIATED GAS (Sm^3/h)	TOTAL PROD.GAS (Sm^3/h)
1	10.35	332	9071	4874	2584	7458
2	27.32	406	35136	18879	6284	25163
3	37.47	494	60660	32592	8198	40791
4	50.54	594	77512	41647	11044	52691
5	56.36	676	101740	54665	12016	66681
6	55.77	771	117325	63039	11775	74814
7	55.41	850	124438	66860	12258	79119
8	54.40	915	142515	76573	12353	88926
9	52.66	962	153409	82427	12482	94908
10	51.01	967	164453	88361	12607	100967
11	49.68	1009	177845	95556	12478	108034
12	50.36	1055	190335	102267	13239	115506
13	48.13	1071	200025	107473	12959	120433
14	52.59	1107	206122	110749	13764	124513
15	54.27	1163	209901	112780	13481	126261
16	58.07	1219	218752	117535	13825	131360
17	60.18	1299	218618	117463	14255	131718
18	64.33	1366	220044	118230	14763	132993
19	66.47	1349	223694	120191	14492	134683
20	61.42	1313	220228	118329	13030	131359
21	56.33	1192	214084	115027	11704	126731
22	51.73	1172	201866	108463	10599	119061
23	46.87	1143	187620	100808	9472	110280
24	42.63	1126	167502	89999	8510	98509
25	37.69	1091	147573	79291	7501	86792
26	34.05	1071	134377	72201	6759	78960
27	30.19	1033	119868	64405	5973	70378
28	26.63	983	106339	57136	5264	62399
29	23.44	931	91671	49255	4652	53907
30	20.52	899	75553	40595	4054	44648
31	16.33	680	59190	31803	3196	34999
32	14.02	608	49999	26865	2752	29617
33	12.07	590	41690	22400	2374	24774
34	9.86	517	33465	17981	1947	19928
35	7.96	434	26682	14336	1597	15934
36	6.64	390	22296	11980	1355	13334
37	5.02	303	16761	9006	1011	10017
38	3.36	187	10905	5859	676	6535
39	2.68	159	7652	4111	553	4664
40	2.37	154	5650	3036	494	3530

SEPARATION PLANT PRODUCTION FORECAST

Year	TOTAL WELL PROD.		PROD. OIL		PROD. WATER		WASTE WATER		HC LIQUIDS SEPARATED	
	Sm^3/h	kg/h	Sm^3/h	kg/h	Sm^3/h	kg/h	Sm^3/h	kg/h	Sm^3/h	kg/h
1	7,800	351,721	10.5	8,489	333	332,048	0.125	122	0	0
2	25,596	469,596	27.6	22,322	407	405,983	0.211	205	2.52	1,696
3	41,323	593,350	37.6	30,509	495	493,944	0.277	271	4.29	2,996
4	53,335	723,828	50.8	41,192	595	593,928	0.334	325	5.08	3,608
5	67,413	835,718	56.5	45,814	678	675,895	0.393	383	7.43	5,304
6	75,641	945,362	55.7	45,210	773	770,873	0.454	444	9.04	6,608
7	80,024	1,031,562	55.3	44,873	852	849,866	0.499	488	9.62	7,038
8	89,896	1,113,791	54.1	43,938	917	914,842	0.544	533	11.85	8,817
9	95,923	1,170,317	52.3	42,454	964	961,829	0.574	563	13.25	9,937
10	101,985	1,185,146	50.5	41,054	969	966,817	0.579	568	14.85	11,214
11	109,093	1,239,226	49.1	39,901	1,011	1,008,800	0.608	598	17.15	13,079
12	116,612	1,299,027	49.7	40,412	1,057	1,054,788	0.635	624	18.44	14,065
13	121,552	1,322,555	47.4	38,548	1,074	1,070,776	0.648	637	20.50	15,752
14	125,673	1,369,112	51.9	42,170	1,110	1,106,770	0.669	657	20.70	15,863
15	127,478	1,429,831	53.5	43,512	1,166	1,162,761	0.707	695	21.81	16,780
16	132,638	1,498,050	57.3	46,576	1,222	1,218,749	0.743	731	23.15	17,847
17	133,078	1,579,954	59.4	48,293	1,302	1,298,747	0.790	777	22.23	17,104
18	134,423	1,652,194	63.6	51,675	1,369	1,365,743	0.830	816	21.91	16,788
19	136,098	1,639,829	65.7	53,395	1,352	1,348,278	0.825	810	23.12	17,819
20	132,733	1,595,178	60.6	49,274	1,316	1,312,737	0.809	795	24.84	19,266
21	127,980	1,462,650	55.5	45,141	1,195	1,191,745	0.739	727	26.48	20,657
22	120,285	1,425,490	50.9	41,420	1,175	1,171,755	0.729	717	25.89	20,252
23	111,470	1,377,085	46.1	37,496	1,146	1,142,767	0.714	703	25.00	19,597
24	99,677	1,335,472	41.9	34,101	1,129	1,125,786	0.703	692	21.70	16,997
25	87,920	1,275,461	37.1	30,136	1,094	1,090,805	0.681	670	18.72	14,649
26	80,065	1,238,511	33.5	27,209	1,074	1,070,818	0.669	659	16.92	13,245
27	71,442	1,182,056	29.6	24,109	1,035	1,032,832	0.646	636	14.93	11,687
28	63,409	1,114,935	26.1	21,254	985	982,847	0.615	605	13.07	10,226
29	54,862	1,045,090	23.0	18,706	933	930,864	0.580	572	10.65	8,315
30	45,568	993,989	20.1	16,383	901	898,883	0.557	548	7.86	6,102
31	35,696	754,695	16.0	13,046	682	679,910	0.421	415	6.22	4,824
32	30,239	671,271	13.8	11,201	609	607,923	0.375	370	5.05	3,908
33	25,376	642,987	11.9	9,640	591	589,933	0.362	356	3.84	2,955
34	20,455	559,632	9.7	7,874	518	516,946	0.315	311	2.91	2,228
35	16,376	468,077	7.8	6,356	435	433,957	0.263	259	2.21	1,685
36	13,731	418,434	6.5	5,299	391	389,964	0.235	232	1.76	1,334
37	10,325	324,370	4.9	4,005	304	302,972	0.183	180	0	0
38	6,726	201,021	3.3	2,684	187	186,983	0.113	111	0	0
39	4,826	169,133	2.6	2,146	159	158,989	0.093	91	0	0
40	3,686	161,823	2.3	1,903	154	153,996	0.085	84	0	0

Year	HC GAS SEPARATED				CO_2 REINJECTED		
	Sm^3/h	kg/h	wt.% CO_2	wt. % C_2	kg/h	vol.% CO_2	wt. % CO_2
1	0	0	0.0%	0.0%	11,044	57.05%	74.56%
2	3,932	4,432	3.8%	46.1%	34,893	87.8%	94.5%
3	5,194	5,898	5.1%	45.5%	59,624	90.7%	95.9%
4	7,106	8,151	4.8%	44.9%	76,611	90.3%	95.7%
5	7,664	8,741	5.8%	45.0%	99,348	91.9%	96.4%
6	7,587	8,692	6.7%	44.5%	113,347	93.0%	97.0%
7	7,924	9,085	6.8%	44.5%	120,119	93.2%	97.0%
8	8,047	9,264	7.7%	44.0%	136,264	94.0%	97.4%
9	8,162	9,419	8.1%	43.8%	145,970	94.3%	97.6%
10	8,250	9,546	8.6%	43.5%	155,692	94.7%	97.7%
11	8,215	9,530	9.3%	43.2%	167,067	95.1%	97.9%
12	8,708	10,112	9.4%	43.1%	178,757	95.2%	97.9%
13	8,574	9,976	10.0%	42.8%	186,594	95.5%	98.1%
14	9,068	10,543	9.7%	43.0%	192,789	95.3%	98.0%
15	8,911	10,364	10.0%	42.8%	195,478	95.5%	98.1%
16	9,139	10,630	10.1%	42.8%	203,233	95.5%	98.1%
17	9,440	10,991	9.8%	42.8%	203,797	95.4%	98.0%
18	9,714	11,274	9.6%	43.0%	205,586	95.3%	98.0%
19	9,562	11,125	9.9%	42.8%	208,434	95.4%	98.0%
20	8,600	10,009	10.7%	42.5%	202,774	95.8%	98.2%
21	7,729	9,001	11.5%	42.3%	195,118	96.1%	98.3%
22	6,995	8,148	11.8%	42.2%	182,985	96.2%	98.4%
23	6,245	7,273	12.2%	42.1%	169,067	96.3%	98.4%
24	5,612	6,535	12.0%	42.1%	151,211	96.3%	98.4%
25	4,949	5,762	11.9%	42.2%	133,336	96.3%	98.4%
26	4,457	5,190	11.9%	42.2%	121,277	96.3%	98.4%
27	3,940	4,587	11.9%	42.2%	108,117	96.4%	98.4%
28	3,472	4,043	11.9%	42.2%	95,887	96.4%	98.5%
29	3,069	3,572	11.5%	42.3%	83,009	96.3%	98.4%
30	2,674	3,111	10.7%	42.6%	68,940	96.1%	98.3%
31	2,098	2,442	10.7%	42.6%	53,979	96.1%	98.3%
32	1,813	2,107	10.4%	42.7%	45,737	96.0%	98.3%
33	1,561	1,811	9.9%	42.9%	38,279	95.8%	98.2%
34	1,280	1,482	9.5%	43.1%	30,788	95.7%	98.2%
35	1,048	1,213	9.2%	43.3%	24,604	95.6%	98.1%
36	885	1,023	8.9%	43.4%	20,558	95.6%	98.1%
37	0	0	0.0%	0.0%	17,190	86.3%	93.1%
38	0	0	0.0%	0.0%	11,229	86.0%	92.9%
39	0	0	0.0%	0.0%	7,896	84.0%	91.9%
40	0	0	0.0%	0.0%	5,833	81.2%	90.3%

OPERATION DATA

Year	LP COMPRESSION INLET		DEHYDRATION INLET		MEMBRANE INLET		REFRIGERATION		RECYCLE COMPRESSION INLET		CO_2 COMPRESSION INLET	
	Sm^3/h	kg/h	Sm^3/h	kg/h	Sm^3/h	kg/h	kg/h Propane	kW Duty	Sm^3/h	kg/h	Sm^3/h	kg/h
1	1,616	2,797	5,515	8,387	0	0	0	0	0	0	6,965	11,044
2	2,993	5,230	21,836	36,061	20,977	34,368	2,886	326	5,169	7,712	19,755	34,893
3	4,019	7,052	36,436	61,845	34,938	58,915	4,819	545	8,323	12,994	33,341	59,624
4	4,942	8,672	47,324	80,036	45,409	76,285	6,230	704	10,888	16,893	42,927	76,611
5	5,790	10,182	60,483	103,827	57,810	98,636	8,200	927	13,567	21,591	55,284	99,348
6	6,538	11,503	67,880	117,775	64,511	111,287	9,660	1,092	14,948	24,222	62,766	113,347
7	7,060	12,415	71,636	124,408	68,047	117,502	10,236	1,157	15,762	25,582	66,482	120,119
8	7,607	13,380	80,928	141,631	76,386	132,954	12,196	1,379	17,513	28,807	75,167	136,264
9	7,948	13,978	86,583	152,055	81,441	142,266	13,420	1,517	18,582	30,758	80,399	145,970
10	8,008	14,086	92,617	163,188	86,791	152,130	14,789	1,672	19,692	32,799	85,631	155,692
11	8,357	14,700	99,357	175,824	92,519	162,891	16,667	1,885	20,878	35,039	91,724	167,067
12	8,708	15,317	106,476	188,510	99,122	174,610	17,890	2,023	22,341	37,542	98,117	178,757
13	8,838	15,546	111,299	197,685	103,023	182,086	19,508	2,206	23,129	39,083	102,287	186,594
14	9,178	16,147	115,018	204,026	106,700	188,327	19,841	2,243	23,984	40,441	105,736	192,789
15	9,654	16,983	116,269	206,575	107,446	189,937	20,642	2,334	24,125	40,778	107,143	195,478
16	10,167	17,888	120,838	214,838	111,442	197,124	21,775	2,462	25,001	42,302	111,364	203,233
17	10,743	18,892	120,567	214,022	111,550	197,002	21,230	2,400	25,084	42,323	111,738	203,797
18	11,280	19,835	121,255	214,940	112,451	198,300	20,991	2,374	25,324	42,622	112,777	205,586
19	11,265	19,818	122,953	218,338	113,555	200,594	21,947	2,482	25,563	43,153	114,262	208,434
20	10,988	10,988	119,974	213,839	109,795	194,669	22,828	2,581	24,550	41,718	110,988	202,774
21	10,078	17,736	116,332	208,029	105,392	187,473	23,641	2,673	23,470	40,116	106,663	195,118
22	9,847	17,320	108,896	194,995	98,161	174,840	22,830	2,581	21,824	37,393	99,970	182,985
23	9,565	16,819	100,397	180,002	90,000	160,493	21,760	2,460	19,981	34,307	92,315	169,067
24	9,287	16,318	88,883	159,268	79,869	142,349	18,994	2,148	17,746	30,440	82,572	151,211
25	8,892	15,613	77,551	138,907	69,784	124,325	16,435	1,858	15,518	26,598	72,812	133,336
26	8,652	15,182	69,952	125,303	62,930	112,118	14,848	1,679	13,989	23,981	66,217	121,277
27	8,273	14,510	61,749	110,604	55,553	98,969	13,104	1,482	12,352	21,172	59,024	108,117
28	7,814	13,699	54,237	97,136	48,816	86,956	11,480	1,298	10,857	18,604	52,343	95,887
29	7,322	12,831	46,237	82,688	41,833	74,411	9,479	1,072	9,323	15,935	45,329	83,009
30	6,948	12,167	37,336	66,555	34,111	60,479	7,190	813	7,638	12,979	37,679	68,940
31	5,277	9,243	29,448	52,496	26,899	47,693	5,678	642	6,011	10,220	29,501	53,979
32	4,687	8,206	24,679	43,941	22,616	40,050	4,656	526	5,071	8,599	25,008	45,737
33	4,470	7,821	20,047	35,592	18,492	32,654	3,613	409	4,164	7,024	20,942	38,279
34	3,876	6,779	15,820	28,033	14,650	25,820	2,772	313	3,309	5,561	16,851	30,788
35	3,227	5,643	12,507	22,121	11,625	20,449	2,133	241	2,632	4,409	13,473	24,604
36	2,871	5,019	10,280	18,152	9,584	16,829	1,713	194	2,171	3,627	11,260	20,558
37	2,226	3,891	7,648	13,501	0	0	0	0	0	0	9,625	17,190
38	1,379	2,411	5,068	8,943	0	0	0	0	0	0	6,293	11,229
39	1,129	1,973	3,453	6,025	0	0	0	0	0	0	4,457	7,896
40	1,026	1,792	2,413	4,132	0	0	0	0	0	0	3,327	5,833

Trains Analysis / UTILITIES CONSUMPTION ESTIMATE

Year	PRIMARY SEP. (#)	LP COMP. + DEHY. (#)	MEMBRANE (#)	REFRIG. COMPRESSOR (#)	RECYCLE COMPRESSOR (#)	CO_2 COMPRESSOR (#)	POWER (kWh/h)	NATURAL GAS (Sm^3/h)	CHEMICALS (TEG) (kg/h)
1	1	1	0	0	0	1	2,066	11.9	0.3
2	1	1	1	1	1	1	4,420	23.4	1.2
3	1	1	1	1	1	1	6,207	33.7	2.0
4	1	1	1	1	1	1	7,513	41.3	2.6
5	1	2	2	1	2	1	9,430	58.6	6.7
6	1	2	2	1	2	2	11,541	63.8	7.6
7	1	2	2	1	2	2	12,051	66.5	8.0
8	1	2	2	2	2	2	13,413	73.0	9.1
9	1	2	2	2	2	2	14,127	77.0	9.7
10	1	2	2	2	2	2	14,834	81.2	10.5
11	1	2	2	2	2	2	15,696	86.0	11.3
12	1	2	2	2	2	2	16,551	91.0	12.1
13	1	2	2	2	2	2	17,159	94.4	12.7
14	1	2	2	2	2	2	17,610	97.0	13.1
15	1	2	2	2	2	2	17,862	97.9	13.2
16	1	2	2	2	2	2	18,471	101.1	13.8
17	1	2	2	2	2	2	18,514	100.9	13.7
18	1	2	2	2	2	2	18,655	101.4	13.8
19	1	2	2	2	2	2	18,896	102.6	14.0
20	1	2	2	2	2	2	18,559	100.5	13.7
21	1	2	2	2	2	2	18,058	98.0	13.3
22	1	2	2	2	2	2	17,205	92.7	12.5
23	1	2	2	2	2	2	16,219	86.7	11.5
24	1	2	2	2	2	2	14,859	78.6	10.2
25	1	2	2	2	2	2	13,506	70.6	8.9
26	1	2	2	2	2	2	12,604	65.3	8.0
27	1	2	1	2	1	2	11,411	59.5	7.1
28	1	2	1	1	1	1	9,192	54.2	6.2
29	1	2	1	1	1	1	8,194	48.6	5.3
30	1	2	1	1	1	1	7,109	42.3	4.3
31	1	1	1	1	1	1	5,845	28.7	1.7
32	1	1	1	1	1	1	5,208	25.4	1.4
33	1	1	1	1	1	1	4,644	22.1	1.1
34	1	1	1	1	1	1	4,067	19.1	0.9
35	1	1	1	1	1	1	3,585	16.8	0.7
36	1	1	1	1	1	1	3,273	15.2	0.6
37	1	1	0	0	0	1	2,373	13.4	0.4
38	1	1	0	0	0	1	1,982	11.6	0.3
39	1	1	0	0	0	1	1,785	10.4	0.2
40	1	1	0	0	0	1	1,667	9.7	0.1

Power Specific Consumpt		
Primary Separation	66	kW/train
LP Compression	0.0813138	kW/Sm^3 inlet
Dehydration + Membrane	12	kW/train
Refrigeration	0.7510073	kW/kWduty
Recycle Compression	0.071979	kW/Sm^3 inlet
CO2 Compression	0.0966376	kW/Sm^3 inlet

Nat. Gas. Specific Consu	0.0007045	Sm^3/Sm^3 inlet

TEG Specific Consumptic	3.206E-05	kg/Sm^3 inlet

SEE NEXT PAGE FOR REST OF THE TABLE

SNC·LAVALIN

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Rev. E/MAR.31.2008

CASE #2 CO2 SEPARATION

Year	PARASITIC CO_2 CALCULATION: POWER PARASITIC CO_2 (to/h)	VENT PARASITIC CO_2 (to/h)	TOTAL (to/h)	TOTAL (to/year)	% of CO_2 REINJECTED	GAS REINJECTED (to/year)	GAS REINJECTED (wt. % CO2)	CO_2 REINJECTED (to/year)	C_2 RECOVERED (to/year)	C_1 RECOVERED (to/year)	C_3^+ RECOVERED (to/year)	UTILITIES COSTS: Power (kW/to)	Power ($/to)	Power ($/year)	Natural Gas (Sm^3/to)	Natural Gas ($/to)	Natural Gas ($/year)	TEG (kg/to)	TEG ($/to)	TEG ($/year)	Total Utilities ($/to)	Total Utilities ($/year)	Other variable Costs (maintenance + others) 3% of Capex ($/to)	Other variable Costs ($/year)	Subtotal ($/to)	Subtotal ($/year)	Manpower Add-in 10% of Subtotal ($/to)	Manpower Add-in ($/year)	TOTAL OPEX PLANT ($/to)	TOTAL OPEX PLANT ($/year)	Fixed Costs (Capital Charge) 10% of Capex ($/to)	Fixed Costs ($/year)	REINJECTED GAS UNIT COST: FOB PLANT ($/to)	REINJECTED GAS UNIT COST: OPERATING ONLY FOB PLANT ($/to)	REINJECTED CO_2 UNIT COST: FOB PLANT ($/to)	REINJECTED CO_2 UNIT COST: OPERATING ONLY FOB PLANT ($/to)
1	2.07	0.023	2.09	17,387	25.37%	91,910	74.56%	68,531	0	0	0	187	$14.97	$1,375,778	1.076	$0.266	$24,450	0.024	$0.073	$6,723	$15.31	$1,406,952	$46.38	$4,262,700	$61.69	$5,669,652	$15.22	$1,398,654	$76.90	$7,068,306	$154.60	$14,209,000	$231.50	$76.90	$310.48	$103.14
2	4.42	0.045	4.46	37,154	13.54%	290,377	94.48%	274,349	17,018	8,851	4,926	127	$10.13	$2,942,383	0.670	$0.166	$48,105	0.033	$0.100	$28,909	$10.40	$3,019,397	$19.88	$5,772,900	$30.28	$8,792,297	$4.82	$1,398,654	$35.10	$10,190,951	$66.27	$19,243,000	$101.36	$35.10	$107.29	$37.15
3	6.21	0.065	6.27	52,195	10.97%	496,190	95.88%	475,729	22,315	11,780	7,417	104	$8.33	$4,132,450	0.565	$0.140	$69,266	0.033	$0.100	$49,579	$8.57	$4,251,296	$11.63	$5,772,900	$20.20	$10,024,196	$2.82	$1,398,654	$23.02	$11,422,850	$38.78	$19,243,000	$61.80	$23.02	$64.46	$24.01
4	7.51	0.080	7.59	63,185	10.36%	637,559	95.65%	609,846	30,429	16,279	9,630	98	$7.85	$5,001,845	0.540	$0.133	$85,045	0.033	$0.101	$64,162	$8.08	$5,151,053	$9.05	$5,772,900	$17.13	$10,923,953	$2.19	$1,398,654	$19.33	$12,322,607	$30.18	$19,243,000	$49.51	$19.33	$51.76	$20.21
5	9.43	0.113	9.54	79,416	9.96%	826,772	96.41%	797,123	32,760	17,459	11,999	95	$7.59	$6,278,250	0.590	$0.146	$120,575	0.067	$0.201	$166,469	$7.94	$6,565,294	$8.98	$7,421,250	$16.92	$13,986,544	$1.69	$1,398,654	$18.61	$15,385,199	$29.92	$24,737,500	$48.53	$18.61	$50.33	$19.30
6	11.54	0.123	11.66	97,070	10.61%	943,274	96.95%	914,520	32,202	17,360	13,486	102	$8.15	$7,683,852	0.563	$0.139	$131,295	0.067	$0.200	$188,834	$8.49	$8,003,981	$8.96	$8,447,850	$17.44	$16,451,831	$2.32	$2,188,669	$19.76	$18,640,499	$29.85	$28,159,500	$49.61	$19.76	$51.17	$20.38
7	12.05	0.128	12.18	101,348	10.45%	999,627	97.02%	969,842	33,619	18,145	14,248	100	$8.03	$8,022,742	0.553	$0.137	$136,740	0.066	$0.200	$199,468	$8.36	$8,358,949	$8.45	$8,447,850	$16.81	$16,806,799	$2.19	$2,188,669	$19.00	$18,995,468	$28.17	$28,159,500	$47.17	$19.00	$48.62	$19.59
8	13.41	0.140	13.55	112,789	10.21%	1,133,986	97.39%	1,104,356	33,937	18,504	16,441	98	$7.87	$8,929,648	0.536	$0.132	$150,206	0.067	$0.200	$227,083	$8.21	$9,306,938	$7.71	$8,745,300	$15.92	$18,052,238	$1.93	$2,188,669	$17.85	$20,240,906	$25.71	$29,151,000	$43.56	$17.85	$44.72	$18.33
9	14.13	0.148	14.28	118,797	10.02%	1,214,763	97.56%	1,185,102	34,317	18,812	17,848	97	$7.74	$9,405,135	0.527	$0.130	$158,402	0.067	$0.201	$243,797	$8.07	$9,807,334	$7.20	$8,745,300	$15.27	$18,552,634	$1.80	$2,188,669	$17.07	$20,741,302	$24.00	$29,151,000	$41.07	$17.07	$42.10	$17.50
10	14.83	0.156	14.99	124,745	9.85%	1,295,666	97.72%	1,266,125	34,580	19,065	19,420	95	$7.62	$9,875,593	0.522	$0.129	$167,147	0.067	$0.202	$261,646	$7.95	$10,304,387	$6.75	$8,745,300	$14.70	$19,049,687	$1.69	$2,188,669	$16.39	$21,238,356	$22.50	$29,151,000	$38.89	$16.39	$39.80	$16.77
11	15.70	0.165	15.86	131,995	9.70%	1,390,332	97.91%	1,361,274	34,238	19,035	21,583	94	$7.52	$10,449,484	0.515	$0.127	$176,915	0.067	$0.203	$281,906	$7.85	$10,908,306	$6.29	$8,745,300	$14.14	$19,653,606	$1.57	$2,188,669	$15.71	$21,842,275	$20.97	$29,151,000	$36.68	$15.71	$37.46	$16.05
12	16.55	0.175	16.73	139,195	9.55%	1,487,617	97.94%	1,456,972	36,286	20,196	23,119	93	$7.41	$11,019,065	0.509	$0.126	$187,234	0.068	$0.203	$302,246	$7.74	$11,508,544	$5.88	$8,745,300	$13.61	$20,253,844	$1.47	$2,188,669	$15.09	$22,442,513	$19.60	$29,151,000	$34.68	$15.09	$35.41	$15.40
13	17.16	0.182	17.34	144,307	9.48%	1,552,837	98.07%	1,522,867	35,550	19,925	24,994	92	$7.36	$11,423,670	0.506	$0.125	$194,224	0.068	$0.204	$316,957	$7.69	$11,934,851	$5.63	$8,745,300	$13.32	$20,680,151	$1.41	$2,188,669	$14.73	$22,868,819	$18.77	$29,151,000	$33.50	$14.73	$34.16	$15.02
14	17.61	0.187	17.80	148,100	9.42%	1,604,393	98.02%	1,572,626	37,694	21,058	25,501	91	$7.31	$11,723,739	0.503	$0.124	$199,613	0.068	$0.204	$327,122	$7.64	$12,250,475	$5.45	$8,745,300	$13.09	$20,995,775	$1.36	$2,188,669	$14.45	$23,184,444	$18.17	$29,151,000	$32.62	$14.45	$33.28	$14.74
15	17.86	0.188	18.05	150,219	9.41%	1,626,771	98.08%	1,595,537	36,931	20,699	26,449	91	$7.31	$11,892,115	0.501	$0.124	$201,427	0.068	$0.204	$331,210	$7.64	$12,424,753	$5.38	$8,745,300	$13.01	$21,170,053	$1.35	$2,188,669	$14.36	$23,358,721	$17.92	$29,151,000	$32.28	$14.36	$32.91	$14.64
16	18.47	0.195	18.67	155,337	9.36%	1,691,301	98.10%	1,659,166	37,835	21,231	27,870	91	$7.27	$12,297,438	0.498	$0.123	$208,049	0.068	$0.204	$344,459	$7.60	$12,849,945	$5.17	$8,745,300	$12.77	$21,595,245	$1.29	$2,188,669	$14.06	$23,783,913	$17.24	$29,151,000	$31.30	$14.06	$31.90	$14.33
17	18.51	0.194	18.71	155,686	9.37%	1,695,999	98.00%	1,662,079	39,148	21,952	27,245	91	$7.27	$12,325,601	0.495	$0.122	$207,656	0.067	$0.202	$343,150	$7.59	$12,876,408	$5.16	$8,745,300	$12.75	$21,621,708	$1.29	$2,188,669	$14.04	$23,810,376	$17.19	$29,151,000	$31.23	$14.04	$31.86	$14.33
18	18.66	0.195	18.85	156,874	9.36%	1,710,887	98.00%	1,676,669	40,344	22,517	27,065	91	$7.26	$12,420,020	0.493	$0.122	$208,653	0.067	$0.201	$344,622	$7.58	$12,973,295	$5.11	$8,745,300	$12.69	$21,718,595	$1.28	$2,188,669	$13.97	$23,907,264	$17.04	$29,151,000	$31.01	$13.97	$31.65	$14.26
19	18.90	0.197	19.09	158,895	9.35%	1,734,588	98.00%	1,699,896	39,625	22,220	28,167	91	$7.25	$12,580,201	0.492	$0.122	$211,114	0.067	$0.202	$350,070	$7.58	$13,141,385	$5.04	$8,745,300	$12.62	$21,886,685	$1.26	$2,188,669	$13.88	$24,075,354	$16.81	$29,151,000	$30.69	$13.88	$31.31	$14.16
20	18.56	0.193	18.75	156,054	9.42%	1,687,482	98.20%	1,657,041	35,430	19,991	29,110	92	$7.32	$12,355,628	0.496	$0.123	$206,796	0.068	$0.203	$342,857	$7.65	$12,905,281	$5.18	$8,745,300	$12.83	$21,650,581	$1.30	$2,188,669	$14.13	$23,839,250	$17.27	$29,151,000	$31.40	$14.13	$31.98	$14.39
21	18.06	0.188	18.25	151,847	9.51%	1,623,771	98.33%	1,596,581	31,684	17,978	30,060	93	$7.40	$12,022,352	0.502	$0.124	$201,518	0.068	$0.205	$333,541	$7.73	$12,557,411	$5.39	$8,745,300	$13.12	$21,302,711	$1.35	$2,188,669	$14.47	$23,491,380	$17.95	$29,151,000	$32.42	$14.47	$32.97	$14.71
22	17.21	0.178	17.38	144,665	9.66%	1,522,803	98.39%	1,498,224	28,605	16,273	29,020	94	$7.52	$11,454,463	0.507	$0.125	$190,741	0.068	$0.205	$312,644	$7.85	$11,957,848	$5.74	$8,745,300	$13.60	$20,703,148	$1.44	$2,188,669	$15.03	$22,891,816	$19.14	$29,151,000	$34.18	$15.03	$34.74	$15.28
23	16.22	0.167	16.39	136,362	9.85%	1,406,980	98.44%	1,385,005	25,475	14,527	27,675	96	$7.67	$10,797,908	0.513	$0.127	$178,424	0.068	$0.205	$288,605	$8.01	$11,264,937	$6.22	$8,745,300	$14.22	$20,010,237	$1.56	$2,188,669	$15.78	$22,198,905	$20.72	$29,151,000	$36.50	$15.78	$37.08	$16.03
24	14.86	0.151	15.01	124,915	10.09%	1,258,378	98.43%	1,238,596	22,916	13,053	24,154	98	$7.86	$9,892,518	0.520	$0.129	$161,736	0.068	$0.203	$255,360	$8.19	$10,309,615	$6.95	$8,745,300	$15.14	$19,054,915	$1.74	$2,188,669	$16.88	$21,243,584	$23.17	$29,151,000	$40.05	$16.88	$40.69	$17.15
25	13.51	0.136	13.64	113,527	10.40%	1,109,623	98.42%	1,092,131	20,222	11,509	20,903	101	$8.10	$8,991,748	0.530	$0.131	$145,312	0.067	$0.201	$222,715	$8.44	$9,359,775	$7.88	$8,745,300	$16.32	$18,105,075	$1.97	$2,188,669	$18.29	$20,293,744	$26.27	$29,151,000	$44.56	$18.29	$45.27	$18.58
26	12.60	0.126	12.73	105,939	10.66%	1,009,269	98.44%	993,492	18,213	10,365	18,887	104	$8.31	$8,391,496	0.538	$0.133	$134,299	0.066	$0.199	$200,903	$8.65	$8,726,698	$8.66	$8,745,300	$17.31	$17,471,998	$2.17	$2,188,669	$19.48	$19,660,666	$28.88	$29,151,000	$48.36	$19.48	$49.13	$19.79
27	11.41	0.114	11.52	95,911	10.83%	899,746	98.45%	885,773	16,099	9,162	16,670	106	$8.44	$7,596,688	0.550	$0.136	$122,410	0.066	$0.197	$177,336	$8.78	$7,896,435	$8.37	$7,532,550	$17.15	$15,428,985	$2.43	$2,188,669	$19.58	$17,617,653	$27.91	$25,108,500	$47.49	$19.58	$48.24	$19.89
28	9.19	0.104	9.30	77,363	9.85%	797,971	98.45%	785,633	14,192	8,074	14,605	96	$7.67	$6,119,655	0.565	$0.140	$111,523	0.065	$0.195	$155,742	$8.00	$6,386,920	$7.78	$6,208,500	$15.78	$12,595,420	$1.75	$1,398,654	$17.54	$13,994,075	$25.93	$20,695,000	$43.47	$17.54	$44.15	$17.81
29	8.19	0.093	8.29	68,967	10.14%	690,797	98.41%	679,840	12,578	7,135	12,066	99	$7.90	$5,455,179	0.585	$0.145	$99,927	0.064	$0.192	$132,578	$8.23	$5,687,684	$8.99	$6,208,500	$17.22	$11,896,184	$2.02	$1,398,654	$19.25	$13,294,838	$29.96	$20,695,000	$49.20	$19.25	$50.00	$19.56
30	7.11	0.081	7.19	59,834	10.61%	573,720	98.32%	564,065	11,018	6,213	9,180	103	$8.25	$4,732,557	0.614	$0.152	$87,028	0.062	$0.186	$106,711	$8.59	$4,926,296	$10.82	$6,208,500	$19.41	$11,134,796	$2.44	$1,398,654	$21.85	$12,533,450	$36.07	$20,695,000	$57.92	$21.85	$58.91	$22.22
31	5.84	0.055	5.90	49,102	11.12%	449,209	98.31%	441,635	8,663	4,878	7,247	108	$8.66	$3,891,346	0.533	$0.132	$59,137	0.031	$0.094	$42,084	$8.89	$3,992,568	$12.85	$5,772,900	$21.74	$9,765,468	$3.11	$1,398,654	$24.85	$11,164,122	$42.84	$19,243,000	$67.69	$24.85	$68.85	$25.28
32	5.21	0.049	5.26	43,749	11.70%	380,627	98.27%	374,052	7,487	4,209	5,957	114	$9.11	$3,467,402	0.555	$0.137	$52,226	0.031	$0.093	$35,226	$9.34	$3,554,854	$15.17	$5,772,900	$24.51	$9,327,754	$3.67	$1,398,654	$28.18	$10,726,408	$50.56	$19,243,000	$78.74	$28.18	$80.12	$28.68
33	4.64	0.043	4.69	38,999	12.47%	318,562	98.20%	312,836	6,471	3,616	4,648	121	$9.70	$3,091,625	0.578	$0.143	$45,512	0.030	$0.090	$28,533	$9.94	$3,165,670	$18.12	$5,772,900	$28.06	$8,938,570	$4.39	$1,398,654	$32.45	$10,337,225	$60.41	$19,243,000	$92.86	$32.45	$94.55	$33.04
34	4.07	0.037	4.10	34,153	13.58%	256,219	98.16%	251,493	5,317	2,960	3,583	132	$10.57	$2,707,693	0.622	$0.154	$39,385	0.029	$0.088	$22,473	$10.81	$2,769,551	$22.53	$5,772,900	$33.34	$8,542,451	$5.46	$1,398,654	$38.80	$9,941,106	$75.10	$19,243,000	$113.90	$38.80	$116.04	$39.53
35	3.58	0.032	3.62	30,102	14.99%	204,751	98.10%	200,863	4,366	2,422	2,771	146	$11.66	$2,386,656	0.683	$0.169	$34,585	0.029	$0.087	$17,734	$11.91	$2,438,974	$28.19	$5,772,900	$40.11	$8,211,874	$6.83	$1,398,654	$46.94	$9,610,529	$93.98	$19,243,000	$140.92	$46.94	$143.65	$47.85
36	3.27	0.029	3.30	27,484	16.38%	171,087	98.07%	167,792	3,698	2,043	2,236	159	$12.74	$2,179,241	0.741	$0.183	$31,358	0.028	$0.085	$14,552	$13.01	$2,225,150	$33.74	$5,772,900	$46.75	$7,998,050	$8.18	$1,398,654	$54.92	$9,396,705	$112.48	$19,243,000	$167.40	$54.92	$170.69	$56.00
37	2.37	0.026	2.40	19,963	14.99%	143,059	93.08%	133,157	0	0	0	138	$11.04	$1,579,931	0.779	$0.193	$27,542	0.025	$0.076	$10,823	$11.31	$1,618,296	$29.80	$4,262,700	$41.11	$5,880,996	$9.78	$1,398,654	$50.89	$7,279,651	$99.32	$14,209,000	$150.21	$50.89	$161.38	$54.67
38	1.98	0.022	2.00	16,681	19.21%	93,444	92.92%	86,831	0	0	0	177	$14.12	$1,319,694	1.030	$0.255	$23,804	0.026	$0.077	$7,170	$14.45	$1,350,668	$45.62	$4,262,700	$60.07	$5,613,368	$14.97	$1,398,654	$75.04	$7,012,022	$152.06	$14,209,000	$227.10	$75.04	$244.39	$80.75
39	1.78	0.020	1.80	15,018	24.88%	65,714	91.86%	60,364	0	0	0	226	$18.08	$1,188,049	1.321	$0.327	$21,462	0.024	$0.074	$4,830	$18.48	$1,214,341	$64.87	$4,262,700	$83.35	$5,477,041	$21.28	$1,398,654	$104.63	$6,875,695	$216.23	$14,209,000	$320.86	$104.63	$349.29	$113.90
40	1.67	0.019	1.69	14,028	32.00%	48,541	90.30%	43,831	0	0	0	286	$22.86	$1,109,800	1.663	$0.411	$19,955	0.023	$0.068	$3,312	$23.34	$1,133,067	$87.82	$4,262,700	$111.16	$5,395,767	$28.81	$1,398,654	$139.97	$6,794,421	$292.72	$14,209,000	$432.70	$139.97	$479.19	$155.01
						37,136,597		36,321,845																									$43.95	$17.93	$44.93	$18.33
																																	AVERAGE GAS UNIT COST		AVERAGE PURE CO_2 UNIT COST	

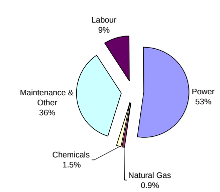
SPECIFIC POWER PARASITIC CO_2	1 kg/kWh	
DEHY. REBOILER FLUE GAS CO2 CON	13.6% wt.	
C_2 RECOVERY EFFICIENCY	100.0%	*assumed*
HC GAS SEPARATED C_1 COMPOSITIO	24.0%	*simulation*
HC GAS SEPARATED C_3^+ COMPOSITIO	8.0%	*simulation*
HC LIQUIDS SEPARATED C_3^+ COMP.	14.0%	*simulation*

Service Factor	95%
Hours/Year Op	8322

POWER COST	$80.00	$/MW
	$0.08	$/kW
NATURAL GAS COST	$7.00	$/Mf^3
	$7.00	$/28.3 m^3
	$0.25	$/m^3
	$184.76	$/tonne
TEG COST	$12.50	$/gal
	$3.30	$/l
	$3.00	$/kg
ETHANE	22.73	$/BBL
	0.4	$/KG
	400	$/TO

PLANT CAPEX	TOTAL	$291,510,000
	PRIMARY SEPARATION	$17,770,000
	LP COMPRESSION	$9,855,000
	DEHYDRATION	$4,665,000
	CO_2 SEPARATION	$24,245,000
	CO_2 COMPRESSION	$34,220,000
	RECYCLE COMPR.	$16,180,000
	REFRIGERATION	$9,915,000
	OSBL	$75,580,000

Case 2 Annual Cash OPEX Breakdown -Year 19



Case 2 Annual Cash OPEX Breakdown - Overall Project Lifetime

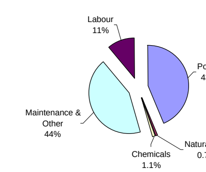


TABLE CONTINUED FROM PREVIOUS PAGE

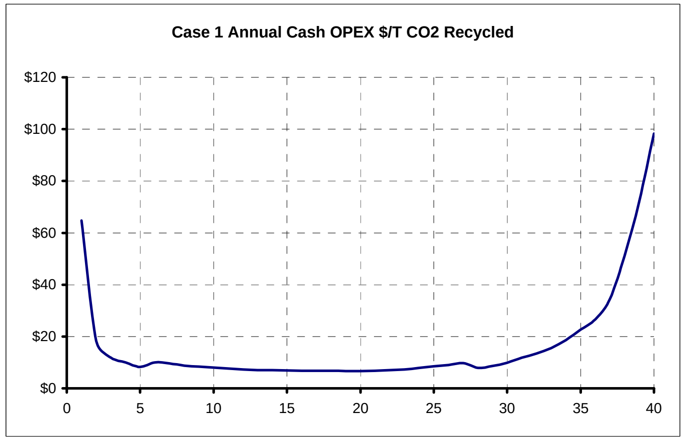
SNC·LAVALIN

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Economics Calculations
Rev. E/MAR.31.2008
CASE #1 NO CO2 SEPARATION

All in CAD Millions

Phase 1 CAPEX	$97.70	
Starting in Year	0	
CAPEX Yearly Split		
year1	25%	$24.43
year2	40%	$39.08
year3	35%	$34.20
Phase 1A CAPEX	$0.00	
Starting in Year	5	
CAPEX Yearly split		
year1	25%	$0.00
year2	40%	$0.00
year3	35%	$0.00
Phase 2 CAPEX	$43.36	
Starting in Year	5	
CAPEX Yearly split		
year1	25%	$10.84
year2	40%	$17.34
year3	35%	$15.18
Unit Power cost	$/MWH	$80.00
Unit natural Gas Cost	$/MCF	$7.00
Unit TEG cost	$/Tonne	$12.00
CO2 Value	$/Tonne	**$19.65**
Ethane value	$/Tonne	$400.00

Discount rate	8%



Discount factor		1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43
YEAR		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
(Year of Operation)					1	2	3	4	5	6	7	8	9
Revenue													
CO2 to Recycle	T/A				68,529	283,023	493,028	630,629	830,200	957,926	1,015,546	1,164,644	1,254,410
Ethane to sales	T/A				0	0	0	0	0	0	0	0	0
CO2 to Recycle	CAD				$1,346,360	$5,560,450	$9,686,344	$12,389,752	$16,310,640	$18,820,037	$19,952,073	$22,881,353	$24,644,960
Ethane to sales	CAD				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Revenue	CAD	$0	$0	$0	$1,346,360	$5,560,450	$9,686,344	$12,389,752	$16,310,640	$18,820,037	$19,952,073	$22,881,353	$24,644,960
Total OPEX	CAD/A				$4,433,310	$5,152,311	$5,811,894	$6,285,002	$6,890,073	$9,617,905	$9,798,173	$10,234,273	$10,498,489
CAPEX	MM CAD/A	$24.43	$39.08	$34.20					$10.84	$17.34	$15.18		
Yearly Net Cash Flow		-$24,425,000	-$39,080,000	-$34,195,000	-$3,086,950	$408,139	$3,874,450	$6,104,749	-$1,419,433	-$8,141,868	-$5,022,101	$12,647,080	$14,146,471
Cumulative Net Cash Flow		-$24,425,000	-$63,505,000	-$97,700,000	-$100,786,950	-$100,378,812	-$96,504,362	-$90,399,612	-$91,819,045	-$99,960,914	-$104,983,014	-$92,335,935	-$78,189,464
PV of yearly cashflow		-$24,425,000	-$36,185,185	-$29,316,701	-$2,450,521	$299,994	$2,636,886	$3,847,027	-$828,225	-$4,398,798	-$2,512,301	$5,858,045	$6,067,179
Cumulative NPV		-$24,425,000	-$60,610,185	-$89,926,886	-$92,377,407	-$92,077,413	-$89,440,527	-$85,593,500	-$86,421,725	-$90,820,523	-$93,332,824	-$87,474,779	-$81,407,600
NPV		**-$0**											
Annual Cash Unit Cost of CO2	$/T				$64.69	$18.20	$11.79	$9.97	$8.30	$10.04	$9.65	$8.79	$8.37
average annual cash unit cost of CO2	$/T				$16.87								
overall weighted average cash unit cost of CO2	$/T				$8.71								
capital charge , percentage of capital in use	$/A				$9,770,000	$9,770,000	$9,770,000	$9,770,000	$10,854,000	$12,588,400	$14,106,000	$14,106,000	$14,106,000
total OPEX incl capital charge	$/A				$14,203,310	$14,922,311	$15,581,894	$16,055,002	$17,744,073	$22,206,305	$23,904,173	$24,340,273	$24,604,489
unit capital charge, percentage of capital in use	10%				$142.57	$34.52	$19.82	$15.49	$13.07	$13.14	$13.89	$12.11	$11.25
total unit OPEX incl capital charge	$/T				$207.26	$52.72	$31.60	$25.46	$21.37	$23.18	$23.54	$20.90	$19.61
overall weighted average cash unit cost of CO2 including capital charge	$/T				$21.13								

Discount factor		0.40	0.37	0.34	0.32	0.29	0.27	0.25	0.23	0.21	0.20	0.18	0.17
YEAR		**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
(Year of Operation)		10	11	12	13	14	15	16	17	18	19	20	21
Revenue													
CO2 to Recycle	T/A	1,346,257	1,456,881	1,559,839	1,640,238	1,690,015	1,720,240	1,792,554	1,789,747	1,800,067	1,830,770	1,802,765	1,754,309
Ethane to sales	T/A	0	0	0	0	0	0	0	0	0	0	0	0
CO2 to Recycle	CAD	$26,449,438	$28,622,834	$30,645,606	$32,225,177	$33,203,119	$33,796,957	$35,217,675	$35,162,525	$35,365,281	$35,968,500	$35,418,294	$34,466,287
Ethane to sales	CAD	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Revenue	CAD	$26,449,438	$28,622,834	$30,645,606	$32,225,177	$33,203,119	$33,796,957	$35,217,675	$35,162,525	$35,365,281	$35,968,500	$35,418,294	$34,466,287
Total OPEX	CAD/A	$10,768,538	$11,086,314	$11,405,414	$11,631,132	$11,797,470	$11,877,949	$12,097,438	$12,100,854	$12,144,647	$12,226,037	$12,106,513	$11,930,248
Yearly Net Cash Flow		$15,680,900	$17,536,520	$19,240,192	$20,594,045	$21,405,649	$21,919,007	$23,120,236	$23,061,671	$23,220,634	$23,742,463	$23,311,781	$22,536,039
Cumulative Net Cash Flow		-$62,508,563	-$44,972,043	-$25,731,851	-$5,137,805	$16,267,844	$38,186,851	$61,307,088	$84,368,759	$107,589,393	$131,331,855	$154,643,637	$177,179,676
PV of yearly cashflow		$6,227,101	$6,448,142	$6,550,536	$6,492,102	$6,248,105	$5,924,027	$5,785,817	$5,343,667	$4,981,945	$4,716,577	$4,287,981	$3,838,232
Cumulative NPV		-$75,180,499	-$68,732,357	-$62,181,821	-$55,689,719	-$49,441,614	-$43,517,587	-$37,731,770	-$32,388,102	-$27,406,157	-$22,689,580	-$18,401,600	-$14,563,368
Annual Cash Unit Cost of CO2	$/T	$8.00	$7.61	$7.31	$7.09	$6.98	$6.90	$6.75	$6.76	$6.75	$6.68	$6.72	$6.80
capital charge , percentage of capital in use	$/A	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000
total OPEX incl capital charge	$/A	$24,874,538	$25,192,314	$25,511,414	$25,737,132	$25,903,470	$25,983,949	$26,203,438	$26,206,854	$26,250,647	$26,332,037	$26,212,513	$26,036,248
unit capital charge, percentage of capital in use	10%	$10.48	$9.68	$9.04	$8.60	$8.35	$8.20	$7.87	$7.88	$7.84	$7.70	$7.82	$8.04
total unit OPEX incl capital charge	$/T	$18.48	$17.29	$16.36	$15.69	$15.33	$15.10	$14.62	$14.64	$14.58	$14.38	$14.54	$14.84

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AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
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CASE #1 NO CO2 SEPARATION

All in CAD Millions

Phase 1 CAPEX	$97.70
Starting in Year	0
CAPEX Yearly Split	
year1	25%
year2	40%
year3	35%
Phase 1A CAPEX	$0.00
Starting in Year	5
CAPEX Yearly split	
year1	25%
year2	40%
year3	35%
Phase 2 CAPEX	$43.36
Starting in Year	5
CAPEX Yearly split	
year1	25%
year2	40%
year3	35%
Unit Power cost	$/MWH
Unit natural Gas Cost	$/MCF
Unit TEG cost	$/Tonne
CO2 Value	$/Tonne
Ethane value	$/Tonne

Discount rate											
Discount factor		0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08
YEAR		**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**
(Year of Operation)		22	23	24	25	26	27	28	29	30	31
Revenue											
CO2 to Recycle	T/A	1,653,301	1,535,617	1,368,818	1,203,987	1,094,799	975,058	863,693	742,875	609,586	478,033
Ethane to sales	T/A	0	0	0	0	0	0	0	0	0	0
CO2 to Recycle	CAD	$32,481,829	$30,169,728	$26,892,691	$23,654,308	$21,509,138	$19,156,629	$16,968,671	$14,595,004	$11,976,314	$9,391,741
Ethane to sales	CAD	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Revenue	CAD	$32,481,829	$30,169,728	$26,892,691	$23,654,308	$21,509,138	$19,156,629	$16,968,671	$14,595,004	$11,976,314	$9,391,741
Total OPEX	CAD/A	$11,607,240	$11,235,195	$10,725,029	$10,219,228	$9,882,174	$9,513,299	$6,808,811	$6,442,748	$6,040,966	$5,637,350
CAPEX	MM CAD/A										
Yearly Net Cash Flow		$20,874,589	$18,934,532	$16,167,662	$13,435,080	$11,626,964	$9,643,330	$10,159,860	$8,152,255	$5,935,348	$3,754,391
Cumulative Net Cash Flow		$198,054,265	$216,988,797	$233,156,459	$246,591,539	$258,218,503	$267,861,833	$278,021,693	$286,173,948	$292,109,297	$295,863,687
PV of yearly cashflow		$3,291,909	$2,764,781	$2,185,896	$1,681,895	$1,347,725	$1,034,995	$1,009,660	$750,138	$505,692	$296,180
Cumulative NPV		-$11,271,459	-$8,506,678	-$6,320,782	-$4,638,887	-$3,291,162	-$2,256,167	-$1,246,508	-$496,369	$9,323	$305,503
NPV											
Annual Cash Unit Cost of CO2	$/T	$7.02	$7.32	$7.84	$8.49	$9.03	$9.76	$7.88	$8.67	$9.91	$11.79
average annual cash unit cost of CO2	$/T										
overall weighted average cash unit cost of CO2	$/T										
capital charge , percentage of capital in use	$/A	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$14,106,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000
total OPEX incl capital charge	$/A	$25,713,240	$25,341,195	$24,831,029	$24,325,228	$23,988,174	$23,619,299	$16,578,811	$16,212,748	$15,810,966	$15,407,350
unit capital charge, percentage of capital in use	10%	$8.53	$9.19	$10.31	$11.72	$12.88	$14.47	$11.31	$13.15	$16.03	$20.44
total unit OPEX incl capital charge	$/T	$15.55	$16.50	$18.14	$20.20	$21.91	$24.22	$19.20	$21.82	$25.94	$32.23

Discount rate											totals
Discount factor		0.07	0.07	0.06	0.06	0.05	0.05	0.05	0.04	0.04	
YEAR		**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	
(Year of Operation)		32	33	34	35	36	37	38	39	40	
Revenue											
CO2 to Recycle	T/A	403,127	334,468	267,612	212,934	177,391	133,157	86,831	60,364	43,831	39,127,100
Ethane to sales	T/A	0	0	0	0	0	0	0	0	0	
CO2 to Recycle	CAD	$7,920,087	$6,571,173	$5,257,680	$4,183,438	$3,485,135	$2,616,088	$1,705,937	$1,185,959	$861,134	$768,716,345
Ethane to sales	CAD	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Total Revenue	CAD	$7,920,087	$6,571,173	$5,257,680	$4,183,438	$3,485,135	$2,616,088	$1,705,937	$1,185,959	$861,134	$768,716,345
Total OPEX	CAD/A	$5,408,667	$5,199,789	$4,994,858	$4,827,246	$4,717,893	$4,580,711	$4,437,731	$4,357,809	$4,308,311	$340,839,041
CAPEX	MM CAD/A										
Yearly Net Cash Flow		$2,511,420	$1,371,384	$262,822	-$643,808	-$1,232,757	-$1,964,623	-$2,731,794	-$3,171,850	-$3,447,177	
Cumulative Net Cash Flow		$298,375,107	$299,746,491	$300,009,313	$299,365,505	$298,132,748	$296,168,125	$293,436,331	$290,264,482	$286,817,305	
PV of yearly cashflow		$183,447	$92,753	$16,459	-$37,332	-$66,187	-$97,668	-$125,747	-$135,188	-$136,040	
Cumulative NPV		$488,950	$581,703	$598,162	$560,830	$494,643	$396,975	$271,228	$136,040	-$0	
NPV											
Annual Cash Unit Cost of CO2	$/T	$13.42	$15.55	$18.66	$22.67	$26.60	$34.40	$51.11	$72.19	$98.29	$8.71
average annual cash unit cost of CO2	$/T										
overall weighted average cash unit cost of CO2	$/T										
capital charge , percentage of capital in use	$/A	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$9,770,000	$485,758,400
total OPEX incl capital charge	$/A	$15,178,667	$14,969,789	$14,764,858	$14,597,246	$14,487,893	$14,350,711	$14,207,731	$14,127,809	$14,078,311	$826,597,441
unit capital charge, percentage of capital in use	10%	$24.24	$29.21	$36.51	$45.88	$55.08	$73.37	$112.52	$161.85	$222.90	
total unit OPEX incl capital charge	$/T	$37.65	$44.76	$55.17	$68.55	$81.67	$107.77	$163.63	$234.04	$321.19	$21.13

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overall weighted average cash unit cost of CO2 including capital charge	$/T

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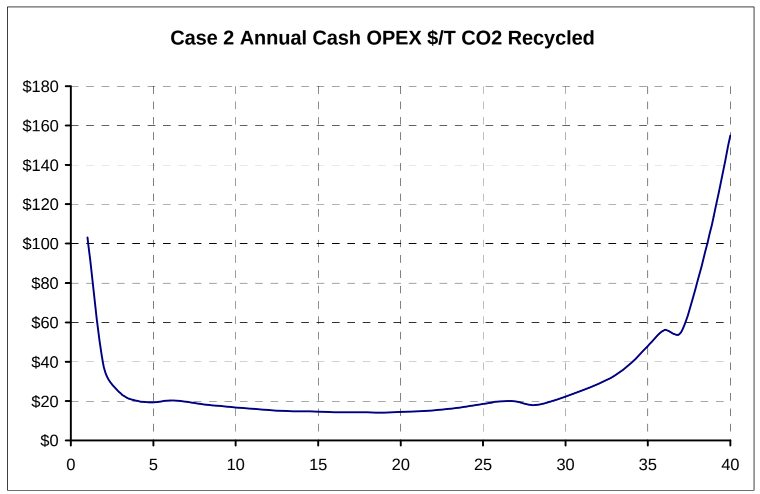
AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Economics Calculations
Rev. E/MAR.31.2008

CASE #2 CO2 SEPARATION

CO2 Value	$/Tonne	**$23.68**			
Ethane value	$/Tonne	**$400**	value of pure ethane. Assume	**$50**	per tonne to purify
Ethane value FOB our facility	$/Tonne	$350			
Methane value	$/Tonne	**$185**	value of pure methane. Assume	**$20**	per tonne to purify
Methane value FOB our facility	$/Tonne	$165			
NGL value	$/Tonne	**$352**	value of C3+. Assume	**$30**	per tonne to purify
NGL value FOB our facility	$/Tonne	$322			
Discount rate		8%			

Discount factor		1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43
YEAR		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
(Year of Operation)					1	2	3	4	5	6	7	8	9
Revenue													
CO2 to Recycle	T/Y				68,531	274,349	475,729	609,846	797,123	914,520	969,842	1,104,356	1,185,102
Ethane to sales	T/Y				0	17,018	22,315	30,429	32,760	32,202	33,619	33,937	34,317
Methane to sales	T/Y				0	8,851	11,780	16,279	17,459	17,360	18,145	18,504	18,812
NGL to sales	T/Y				0	4,926	7,417	9,630	11,999	13,486	14,248	16,441	17,848
CO2 to Recycle	$				$1,622,918	$6,497,003	$11,265,989	$14,442,087	$18,877,096	$21,657,245	$22,967,341	$26,152,841	$28,065,032
Ethane to sales	$				$0.00	$5,956,316.65	$7,810,398.31	$10,650,281.37	$11,466,029.46	$11,270,606.27	$11,766,531.68	$11,878,086.61	$12,010,902.76
Methane to sales	$				$0.00	$1,458,288.52	$1,940,840.33	$2,682,055.39	$2,876,446.83	$2,860,198.11	$2,989,490.95	$3,048,566.92	$3,099,445.84
NGL to sales	$				$0.00	$1,586,182.85	$2,388,202.39	$3,100,985.67	$3,863,745.94	$4,342,333.49	$4,587,984.94	$5,293,876.69	$5,747,063.62
Total Revenue	$	$0	$0	$0	$1,622,918	$15,497,791	$23,405,430	$30,875,410	$37,083,318	$40,130,383	$42,311,349	$46,373,371	$48,922,444
Cost													
Total OPEX	$/Y				$7,068,306	$10,190,951	$11,422,850	$12,322,607	$15,385,199	$18,640,499	$18,995,468	$20,240,906	$20,741,302
CAPEX	MM $/Y	$35.52	$69.42	$69.87	$17.62	$0.00	$25.14	$44.58	$19.44	$7.93	$1.98	$0.00	$0.00
Yearly Net Cash Flow		-$35,522,500	-$69,421,000	-$69,867,500	-$23,064,388	$5,306,839	-$13,157,420	-$26,029,697	$2,255,620	$13,557,883	$21,332,881	$26,132,465	$28,181,142
Cumulative Net Cash Flow		-$35,522,500	-$104,943,500	-$174,811,000	-$197,875,388	-$192,568,548	-$205,725,968	-$231,755,665	-$229,500,046	-$215,942,162	-$194,609,282	-$168,476,817	-$140,295,675
PV of yearly cashflow		-$35,522,500	-$64,278,704	-$59,900,120	-$18,309,254	$3,900,685	-$8,954,719	-$16,403,125	$1,316,132	$7,324,903	$10,671,752	$12,104,387	$12,086,409
Cumulative NPV		-$35,522,500	-$99,801,204	-$159,701,324	-$178,010,578	-$174,109,893	-$183,064,612	-$199,467,736	-$198,151,604	-$190,826,701	-$180,154,950	-$168,050,562	-$155,964,154
NPV		**-$0**											
Annual Cash Unit Cost of CO2	$/T				$103.14	$37.15	$24.01	$20.21	$19.30	$20.38	$19.59	$18.33	$17.50
average annual cash unit cost of CO2	$/T				$31.16								
overall weighted average cash unit cost of CO2	$/T				$18.33								
capital charge , percentage of capital in use	$/Y				$19,243,000	$19,243,000	$21,757,000	$26,215,250	$28,159,500	$28,952,700	$29,151,000	$29,151,000	$29,151,000
total OPEX incl capital charge	$/Y				$26,311,306	$29,433,951	$33,179,850	$38,537,857	$43,544,699	$47,593,199	$48,146,468	$49,391,906	$49,892,302
unit capital charge, percentage of capital in use	10%				$280.79	$70.14	$45.73	$42.99	$35.33	$31.66	$30.06	$26.40	$24.60
total unit OPEX incl capital charge	$/T				$383.93	$107.29	$69.75	$63.19	$54.63	$52.04	$49.64	$44.72	$42.10
overall weighted average cash unit cost of CO2 including capital charge	$/T				$45.44								

Discount factor	0.40	0.37	0.34	0.32	0.29	0.27	0.25	0.23	0.21	0.20	0.18	0.17	0.16
YEAR	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
(Year of Operation)	10	11	12	13	14	15	16	17	18	19	20	21	22
Revenue													
CO2 to Recycle	1,266,125	1,361,274	1,456,972	1,522,867	1,572,626	1,595,537	1,659,166	1,662,079	1,676,669	1,699,896	1,657,041	1,596,581	1,498,224
Ethane to sales	34,580	34,238	36,286	35,550	37,694	36,931	37,835	39,148	40,344	39,625	35,430	31,684	28,605
Methane to sales	19,065	19,035	20,196	19,925	21,058	20,699	21,231	21,952	22,517	22,220	19,991	17,978	16,273
NGL to sales	19,420	21,583	23,119	24,994	25,501	26,449	27,870	27,245	27,065	28,167	29,110	30,060	29,020
CO2 to Recycle	$29,983,781	$32,237,074	$34,503,331	$36,063,835	$37,242,197	$37,784,775	$39,291,616	$39,360,582	$39,706,102	$40,256,154	$39,241,293	$37,809,506	$35,480,261
Ethane to sales	$12,010,902.76	$12,102,951.94	$11,983,457.71	$12,699,956.90	$12,442,626.02	$13,192,768.47	$12,925,781.92	$13,242,205.54	$13,701,771.88	$13,868,821.05	$12,400,338.19	$11,089,266.88	$10,011,848.85
Methane to sales	$3,141,131.97	$3,136,054.79	$3,327,415.51	$3,282,834.03	$3,469,406.68	$3,410,308.78	$3,497,877.66	$3,616,733.47	$3,709,858.36	$3,660,827.94	$3,293,688.17	$2,961,998.83	$2,681,127.37
NGL to sales	$6,253,175.48	$6,949,595.83	$7,444,357.29	$8,048,169.21	$8,211,349.48	$8,516,665.90	$8,974,135.73	$8,772,856.67	$8,714,975.49	$9,069,819.25	$9,373,464.19	$9,679,312.21	$9,344,499.87
Total Revenue	$51,388,992	$54,425,677	$57,258,561	$60,094,795	$61,365,579	$62,904,518	$64,689,412	$64,992,377	$65,832,708	$66,855,623	$64,308,783	$61,540,084	$57,517,737
Cost													
Total OPEX	$21,238,356	$21,842,275	$22,442,513	$22,868,819	$23,184,444	$23,358,721	$23,783,913	$23,810,376	$23,907,264	$24,075,354	$23,839,250	$23,491,380	$22,891,816
CAPEX	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Yearly Net Cash Flow	$30,150,636	$32,583,402	$34,816,048	$37,225,976	$38,181,135	$39,545,797	$40,905,498	$41,182,001	$41,925,444	$42,780,269	$40,469,534	$38,048,704	$34,625,921
Cumulative Net Cash Flow	-$110,145,039	-$77,561,637	-$42,745,588	-$5,519,612	$32,661,523	$72,207,320	$113,112,819	$154,294,820	$196,220,264	$239,000,533	$279,470,066	$317,518,770	$352,144,691
PV of yearly cashflow	$11,973,232	$11,980,849	$11,853,508	$11,735,180	$11,144,709	$10,688,001	$10,236,561	$9,542,367	$8,995,029	$8,498,546	$7,443,987	$6,480,276	$5,460,485
Cumulative NPV	-$143,990,921	-$132,010,072	-$120,156,564	-$108,421,384	-$97,276,674	-$86,588,673	-$76,352,112	-$66,809,745	-$57,814,716	-$49,316,170	-$41,872,184	-$35,391,908	-$29,931,423
Annual Cash Unit Cost of CO2	$16.77	$16.05	$15.40	$15.02	$14.74	$14.64	$14.33	$14.33	$14.26	$14.16	$14.39	$14.71	$15.28
capital charge , percentage of capital in use	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$29,151,000
total OPEX incl capital charge	$50,389,356	$50,993,275	$51,593,513	$52,019,819	$52,335,444	$52,509,721	$52,934,913	$52,961,376	$53,058,264	$53,226,354	$52,990,250	$52,642,380	$52,042,816
unit capital charge, percentage of capital in use	$23.02	$21.41	$20.01	$19.14	$18.54	$18.27	$17.57	$17.54	$17.39	$17.15	$17.59	$18.26	$19.46
total unit OPEX incl capital charge	$39.80	$37.46	$35.41	$34.16	$33.28	$32.91	$31.90	$31.86	$31.65	$31.31	$31.98	$32.97	$34.74



SEE NEXT PAGE FOR REST OF THE TABLE TABLE CON

AERI CO2 ENHANCED HYDROCARBON RECOVERY STUDY
PROJECT # : 017935
Economics Calculations
Rev. E/MAR.31.2008
CASE #2 CO2 SEPARATION

SNC·LAVALIN

CO2 Value	$/Tonne
Ethane value	$/Tonne
Ethane value FOB our facility	$/Tonne
Methane value	$/Tonne
Methane value FOB our facility	$/Tonne
NGL value	$/Tonne
NGL value FOB our facility	$/Tonne
Discount rate	

Discount factor		0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08
YEAR		**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**
(Year of Operation)		23	24	25	26	27	28	29	30	31
Revenue										
CO2 to Recycle	T/Y	1,385,005	1,238,596	1,092,131	993,492	885,773	785,633	679,840	564,065	441,635
Ethane to sales	T/Y	25,475	22,916	20,222	18,213	16,099	14,192	12,578	11,018	8,663
Methane to sales	T/Y	14,527	13,053	11,509	10,365	9,162	8,074	7,135	6,213	4,878
NGL to sales	T/Y	27,675	24,154	20,903	18,887	16,670	14,605	12,066	9,180	7,247
CO2 to Recycle	$	$32,799,054	$29,331,869	$25,863,350	$23,527,424	$20,976,468	$18,604,993	$16,099,649	$13,357,921	$10,458,606
Ethane to sales	$	$8,916,366.90	$8,020,684.44	$7,077,799.12	$6,374,663.78	$5,634,667.78	$4,967,239.49	$4,402,226.94	$3,856,252.58	$3,032,098.87
Methane to sales	$	$2,393,426.07	$2,150,588.94	$1,896,192.31	$1,707,769.00	$1,509,425.83	$1,330,274.95	$1,175,547.69	$1,023,586.38	$803,628.34
NGL to sales	$	$8,911,240.29	$7,777,442.75	$6,730,853.09	$6,081,486.69	$5,367,881.80	$4,702,916.43	$3,885,157.92	$2,955,866.27	$2,333,405.05
Total Revenue	$	$53,020,087	$47,280,585	$41,568,194	$37,691,343	$33,488,443	$29,605,424	$25,562,581	$21,193,627	$16,627,738
Cost										
Total OPEX	$/Y	$22,198,905	$21,243,584	$20,293,744	$19,660,666	$17,617,653	$13,994,075	$13,294,838	$12,533,450	$11,164,122
CAPEX	MM $/Y	$0.00	$0.00	$0.00	$0.00	-$40.43	-$48.80	$0.00	$0.00	-$9.86
Yearly Net Cash Flow		$30,821,182	$26,037,002	$21,274,450	$18,030,677	$56,295,790	$64,411,349	$12,267,743	$8,660,177	$15,318,616
Cumulative Net Cash Flow		$382,965,873	$409,002,875	$430,277,325	$448,308,002	$504,603,792	$569,015,141	$581,282,884	$589,943,060	$605,261,676
PV of yearly cashflow		$4,500,444	$3,520,249	$2,663,281	$2,090,003	$6,042,087	$6,401,028	$1,128,829	$737,847	$1,208,469
Cumulative NPV		-$25,430,979	-$21,910,730	-$19,247,449	-$17,157,446	-$11,115,359	-$4,714,331	-$3,585,502	-$2,847,654	-$1,639,185
NPV										
Annual Cash Unit Cost of CO2	$/T	$16.03	$17.15	$18.58	$19.79	$19.89	$17.81	$19.56	$22.22	$25.28
average annual cash unit cost of CO2	$/T									
overall weighted average cash unit cost of CO2	$/T									
capital charge , percentage of capital in use	$/Y	$29,151,000	$29,151,000	$29,151,000	$29,151,000	$25,108,500	$20,228,500	$20,228,500	$20,228,500	$19,243,000
total OPEX incl capital charge	$/Y	$51,349,905	$50,394,584	$49,444,744	$48,811,666	$42,726,153	$34,222,575	$33,523,338	$32,761,950	$30,407,122
unit capital charge, percentage of capital in use	10%	$21.05	$23.54	$26.69	$29.34	$28.35	$25.75	$29.75	$35.86	$43.57
total unit OPEX incl capital charge	$/T	$37.08	$40.69	$45.27	$49.13	$48.24	$43.56	$49.31	$58.08	$68.85
overall weighted average cash unit cost of CO2 including capital charge	$/T									

Discount factor		0.07	0.07	0.06	0.06	0.05	0.05	0.05	0.04	0.04	totals
YEAR		**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	
(Year of Operation)		32	33	34	35	36	37	38	39	40	
Revenue											
CO2 to Recycle	T/Y	374,052	312,836	251,493	200,863	167,792	133,157	86,831	60,364	43,831	36,321,845
Ethane to sales	T/Y	7,487	6,471	5,317	4,366	3,698	0	0	0	0	
Methane to sales	T/Y	4,209	3,616	2,960	2,422	2,043	0	0	0	0	
NGL to sales	T/Y	5,957	4,648	3,583	2,771	2,236	0	0	0	0	
CO2 to Recycle	$	$8,858,134	$7,408,450	$5,955,745	$4,756,755	$3,973,562	$3,153,363	$2,056,290	$1,429,523	$1,037,988	$860,157,205
Ethane to sales	$	$2,620,538.65	$2,264,934.42	$1,860,866.58	$1,528,101.52	$1,294,206.80	$0.00	$0.00	$0.00	$0.00	$306,332,499
Methane to sales	$	$693,478.92	$595,831.98	$487,734.92	$399,040.25	$336,664.59	$0.00	$0.00	$0.00	$0.00	$80,647,787
NGL to sales	$	$1,918,024.79	$1,496,653.15	$1,153,649.56	$892,179.99	$719,965.69	$0.00	$0.00	$0.00	$0.00	$195,189,476
Total Revenue	$	$14,090,176	$11,765,869	$9,457,997	$7,576,077	$6,324,399	$3,153,363	$2,056,290	$1,429,523	$1,037,988	$1,442,326,966
Cost											
Total OPEX	$/Y	$10,726,408	$10,337,225	$9,941,106	$9,610,529	$9,396,705	$7,279,651	$7,012,022	$6,875,695	$6,794,421	$665,717,369
CAPEX	MM $/Y	$0.00	$0.00	$0.00	$0.00	$0.00	-$50.34	$0.00	$0.00	$0.00	$142
Yearly Net Cash Flow		$3,363,768	$1,428,645	-$483,109	-$2,034,452	-$3,072,305	$46,213,712	-$4,955,732	-$5,446,172	-$5,756,433	
Cumulative Net Cash Flow		$608,625,444	$610,054,089	$609,570,979	$607,536,528	$604,464,222	$650,677,934	$645,722,202	$640,276,030	$634,519,597	
PV of yearly cashflow		$245,707	$96,626	-$30,255	-$117,969	-$164,954	$2,297,441	-$228,117	-$232,123	-$227,172	
Cumulative NPV		-$1,393,478	-$1,296,852	-$1,327,106	-$1,445,076	-$1,610,029	$687,412	$459,295	$227,172	-$0	
NPV											
Annual Cash Unit Cost of CO2	$/T	$28.68	$33.04	$39.53	$47.85	$56.00	$54.67	$80.75	$113.90	$155.01	$18.33
average annual cash unit cost of CO2	$/T										
overall weighted average cash unit cost of CO2	$/T										
capital charge , percentage of capital in use	$/Y	$19,243,000	$19,243,000	$19,243,000	$19,243,000	$19,243,000	$14,209,000	$14,209,000	$14,209,000	$14,209,000	$984,678,450
total OPEX incl capital charge	$/Y	$29,969,408	$29,580,225	$29,184,106	$28,853,529	$28,639,705	$21,488,651	$21,221,022	$21,084,695	$21,003,421	$1,650,395,819
unit capital charge, percentage of capital in use	10%	$51.44	$61.51	$76.52	$95.80	$114.68	$106.71	$163.64	$235.39	$324.18	
total unit OPEX incl capital charge	$/T	$80.12	$94.55	$116.04	$143.65	$170.69	$161.38	$244.39	$349.29	$479.19	$45.44
overall weighted average cash unit cost of CO2 including capital charge	$/T										

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Appendix 3

Request for Proposal

CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta

Alberta Energy Research Institute
RFP# AERI007

REQUEST FOR PROPOSALS (RFP)

RFP #: AERI007

Alberta Advanced Education & Technology
Alberta Energy Research Institute
25th Floor, AMEC Place
801 - 6 Avenue S.W.
Calgary, Alberta, T2P3W2

CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta

	RFP Issue Date: June 19, 2007 **RFP Closing**: 4:30 pm Alberta Time, July 16, 2007 **Contracting Administrator**: Susan Emilsson **Fax**: (403) 297 3638 **E-mail**: susan.emilsson@gov.ab.ca

Vendors may obtain this document directly from the Contracting Administrator.
Facsimile or digital Proposals (i.e., Word 2000 or PDF format for text) will be accepted, however, the required THREE (3) of print versions must also be sent. All materials and copies of the Proposal must be received by the RFP Closing prescribed above.

TABLE OF CONTENTS

1. DEFINITIONS

Vendors are advised to pay careful attention to the wording used throughout this Request for Proposals (RFP). Failure to satisfy any term or condition of this RFP may deem the Proposal ineligible for consideration by Alberta Advanced Education & Technology.

Throughout this RFP, terminology is used as follows:

Alberta Advanced Education & Technology means Her Majesty the Queen in Right of Alberta as represented by the Minister of Advanced Education & Technology.

ADOE means the Alberta Department of Energy.

AERI means the Alberta Energy Research Institute.

Alberta Time means Mountain Standard Time or Daylight Saving Time as provided for in the *Daylight Saving Time Act* of Alberta.

APC means the Alberta Purchasing Connection (www.purchasingconnection.ca), the service used by the Government of Alberta that provides an open and competitive marketplace to advertise business opportunities, release open bidding opportunities and support the procurement process.

Business Day means 8:15 a.m. to 4:30 p.m., Alberta Time, Monday to Friday, excluding statutory holidays observed by Alberta Advanced Education & Technology.

Business Hours means 8:15 a.m. to 4:30 p.m., Alberta Time, on Business Days.

CCS means CO_2 Capture and Storage.

Consortium means two or more individuals and/or organizations that together submit a Proposal. Note that when a Consortium submits a Proposal, the Proposal Form in Appendix “B” must be used.

Contract means an executed agreement between a successful Vendor and Alberta Advanced Education & Technology to provide the Deliverables described in this RFP.

Deliverables mean the tasks described in section 2.3, and includes all the working papers, surveys, notes, plans, designs, reports, records, studies, drawings, examinations, assessments, procedures, specifications, evaluations, results, conclusions, interpretations, calculations, analyses, systems, software, source code, documents, writings, programs, hardware, devices, data or any components of these, regardless of how they are represented, stored, produced, or acquired.

EHR means Enhanced Hydrocarbon Recovery.

Evaluation Team means the individuals who, on behalf of Alberta Advanced Education & Technology, will evaluate the Proposals to this RFP.

Expertise means knowledge, skills and/or experience gained through post-secondary education, employment, voluntary activities, and continuous learning.

FOIP means the *Freedom of Information and Protection of Privacy Act* of Alberta, R.S.A. 2000, c. F-25, as amended, revised or substituted from time to time.

Personal Information means recorded information about an identifiable individual defined in section 1(n) of *FOIP*, R.S.A. 2000, c. F-25, as amended.

Prime Vendor means the Vendor in a Consortium that is responsible for the completion of all Deliverables and is accountable for all terms and conditions of a Contract.

Proposal means the Vendor's response to this RFP and includes all the Vendor's attachments.

RFP means this Request for Proposals document and associated documentation and appendices.

Vendor means an individual, organization or Consortium providing a Proposal to this RFP.

Vendor's Resource(s) means the personnel assigned by the Vendor to complete the Deliverables pursuant to a Contract, and includes its employees, subcontractors and agents.

References to "Alberta Advanced Education & Technology", "Government of Alberta", "Her Majesty", "Minister", and "Ministry" mean "Her Majesty the Queen in right of Alberta" and are only used for administrative purposes.

Headings are used for convenience only, and they do not affect the meaning or interpretation of the clauses.

Words in the singular include the plural and vice versa.

2. CO_2 ENHANCED HYDROCARBON RECOVERY: INCREMENTAL RECOVERY AND CO_2 STORAGE POTENTIAL

2.1 Preamble

In the Ministry of Advanced Education & Technology, the Alberta Energy Research Institute (AERI) works with industry and other government ministries to promote innovation and technology that will enable Alberta's energy sector to evolve. Its strategic focus areas include conventional and unconventional oil & gas recovery and upgrading, clean coal, electricity, renewable and alternative energy, CO_2 management and water management. Background information on AERI is available at: http://www.aeri.ab.ca/.

The Alberta Department of Energy (ADOE) is responsible for ensuring the development of Alberta's energy resources are appropriate, environmentally sustainable, and in the public interest. To accomplish this goal, Alberta also supports further the development of enhanced recovery technologies, alternate sources of energy, improved energy efficiencies, and emissions reductions technologies, while maintaining a competitive royalty and regulatory framework necessary to attract capital investment from world markets. Background information on ADOE is available at http://www.energy.gov.ab.ca/.

ADOE and AERI invite Vendors to submit a proposal to complete a detailed reservoir and development analysis to quantify the potential for incremental recovery and CO_2 Capture and Storage (CCS) pertaining to CO_2 Enhanced Hydrocarbon Recovery (EHR) current and future activities in Alberta. The intention is to study representative pools in detail to predict the incremental oil recovery and CO_2 storage in the pool and develop a methodology to extrapolate the findings to the remainder of the pools amenable to CO_2 EOR. Development plans including capital and operating cost estimates, schedule of expenditures, etc. are required to permit the ADOE to complete evaluation of the economic and crown royalty impact of the CO_2 EOR.

Vendors are requested to provide complete details on the approach that they will take to complete the study. Vendors are encouraged to recommend alternative approaches to complete the work. It is the intention of AERI and ADOE to work closely with the successful Vendor to finalize the study scope, pools to be evaluated and data sources. Proposals shall include the estimated effort required to complete the work.

2.2 Term of Contract

The Deliverables must be completed on or before March 1, 2008.

2.3 Description of Deliverables

The successful Vendor shall provide AERI and ADOE with a detailed report for the work completed, including performance predictions for both continued current operation and CO_2 EHR development in a format that ADOE can conveniently consolidate into their Royalty model for economic analysis and AERI can use to identify CCS technology gaps. The successful Vendor may also be required to provide a summary report of the final predictions but excluding methodology and any discussion of how any confidential information was used.

2.4 Required Expertise

The Vendor <u>must</u> demonstrate expertise in engineering design and project implementation pertaining to Enhanced Hydrocarbon Recovery and Carbon Dioxide Capture and Storage. The Vendor shall provide information on the qualifications and experience of the corporation and key personnel to be assigned to complete the study.

2.5 Proposal Format

Vendors should review section 3 for an explanation of the requirements for a compliant Proposal

The documents are required to form a compliant Proposal include a proposal submission letter, Vendor Profile, RFP requirement and detailed budget.

2.6 Proposal Content

Only Proposals that provide information for all of the following tasks will be considered:

Task 1A: Identify, Screen Study Pools:
AERI and ADOE have identified oil pools with miscible CO_2 EHR and storage potential. A list of these pools, Tables 1A, 1B & 1C, is attached as Appendix C. The following summarizes the pools to be studied.

Miscible Horizontal CO_2 EHR - Tables 1A:
Seventy (70) horizontal pools with CO_2 EHR potential have been identified; nine (9) of these pools have both waterflood and solvent flood areas that have CO_2 EHR potential. The following distribution of studies is proposed:

1. At least two (2) high quality areas of the five (5) Cardium pools with different characteristics need to be analysed.
2. At least one (1) of the eight (8) Beaverhill Lake Pools that have had horizontal hydrocarbon miscible solvent (HCMS) floods need to be analysed to determine both oil and hydrocarbon solvent recovery.
3. At least two (2) pools with significantly different reservoir characteristics should be analysed from the ten (10) areas in the Beaverhill Lake Pools that have been water flooded.
4. At least one (1) of the nine (9) D-2 pools, that have been water flooded or have a strong natural water drive should be analysed.
5. At least one (1) of the five (5) D-3 pools that have been water flooded or have a strong natural water drive should be analysed.
6. At least three (3) pools of the forty-two (42) other pools in various pool types should be selected for further study.

Immiscible Horizontal CO_2 EHR - Tables 1B:
Sixty-five (65) horizontal pools with immiscible CO_2 EHR potential have been identified, the major pool types include:

1. One (1) of the thirteen (13) Mannville Pools that have been water flooded or has a strong natural water drive should be analysed.

2. One (1) of the nine (9) Dina Pools that have been water flooded or have a strong natural water drive should be analysed.
3. At least one (1) of the forty-three (43) other pools should be selected for further study.

Oil Pools with Large Gas Caps - Tables 1C:
Eighty-two (82) pools with large gas caps have the potential to store a significant volume of CO_2. However there is a concern that the gas cap will be a large thief zone precluding or dramatically delaying Enhanced Hydrocarbon recovery from the large remaining oil in these pools. Vendors are requested to select pools with gas caps in communication with oil legs for study:

1. At least two (2) of which has been produced with a water fence
2. At least two (2) where the oil was produced prior to gas cap blowdown
3. The above pools should have a variation in the ratio of HCPV between the gas cap and oil leg from low (~25%) to high (~200%).

<u>Task 1B: Group Study Pools</u>:
The pools to be studied should be selected to maximize the number of other pools that can have EHR potential assigned by considering analogue issues like:

1. Formation type and productivity
2. Depth, temperature and pressure data
3. Reservoir fluid properties
4. Development history and past performance
5. Heterogeneity

<u>Task 1C: Final Pool Selection:</u>
AERI and ADOE will work closely with the successful Vendor to finalize the pools to be evaluated. This selection will be impacted by:

1. The amount of EHR that might be developed by the pool type
2. The number of "analogue" pools where the data can be extrapolated to predict EOR
3. The location of the pools to facilitate infrastructure development
4. Participation of the pool operators in the study
5. Suitable pools where the Vendor may have specific expertise to facilitate the work.

<u>Task 1D: Final Selection:</u>
The final selection of pools shall be made to maximize available pool information, which can be completed within the time constraints of this study. Vendor shall identify the sources of data that they plan to utilize completing this work. ADOE has confidential information on performance of CO_2 EHR pilots some of the pools that may be shared with the successful vendor under strict confidentiality.

<u>Task 2: Geology and Reservoir Engineering:</u>

Vendors are requested to provide all information and analysis necessary to provide a performance prediction for oil recovery accurate to approximately plus or minus 25% for the specific fields studied. Vendors shall provide their plan to complete the following:

1. The detail of geological description required for the pools, and how the work will be completed.
2. Vendor shall specify whether to correlations will be used or what additional laboratory and other studies will be required to complete the performance prediction.
3. Simulation tools to be used in the predictions, streamline modelling or numerical simulation, (compositional or black oil) shall be used as required to provide the required predictions.
4. Past performance history match and a production forecast for continued operation of current production strategy is required. This information should include predicted annual average water and HCMS (where applicable) injection and oil, gas HCMS (where applicable), and water production rates and total volumes. In addition to any possible infill or other development required to produce the remaining reserves shall be identified.
5. The CO_2 EHR prediction shall include CO_2 and water injection, and oil, gas, HCMS (where applicable), CO_2, and water production in total, by time step and on an annual basis and a prediction of the total CO_2 stored. It shall be assumed that all of the produced CO_2 shall be recycled to the reservoir.
6. Predict optimum reservoir operating pressure and determine injection required to pre-pressure the reservoir.
7. Identify constraints to pool development (e.g. injectivity, productivity, conformance) and potential research to overcome these barriers.
8. Evaluate different development strategies for the CO_2 EHR prediction including:
    - infill drilling
    - horizontal drilling
    - various CO_2 and water injection strategies (simultaneous, tapered WAG, different WAG ratio's etc)
    - different pattern configuration (5 spot, 9 spot, line drive)
    - different CO_2 HCPV injection volumes (25%, 50%, 75%, & 100%) for best injection strategy
9. Estimate the injection well tubing head pressure for CO_2 injection and CO_2 purity required for the field, including concentration of allowable contaminants.
10. Determine if economics or other constraints preclude recycling the complete produced gas stream.
11. Specify the proposed recovery process for the immiscible CO_2 EHR pools.

<u>Task 3: Development Plan:</u>

Vendors are requested to prepare a development plan for the CO_2 EHR project so that the ADOE can complete an economic analysis of the CO_2 EOR. The ADOE will provide the successful company with a list of the final information tables to be provided.

1. Study should be completed assuming source CO_2 is delivered to a central point in the field at injection pressure.
2. Development strategies should allow for 8 – 12 years of constant source CO_2 supply to the pool before significant decline in source CO_2 requirement occurs.
3. Study should identify new wells, well re-completions, use or replacement of existing injection and gathering pipeline systems, and treating and water injection facilities. Where suitable existing infrastructure should be reused.
4. Appropriate plant to recycle either the full produced gas stream or capture the CO_2 from the produced gas to meet reservoir needs.
5. Capital and operating cost estimates with an approximate plus or minus 25% accuracy shall be provided for the cases. Energy requirements and emissions of CO_2 from the operation of the EHR project shall be estimated. Capital expenditures shall be phased consistent with the development plan. All assumptions used in the cost estimates shall be included.

2.7 Evaluation Criteria

Vendors should review section 4 for a description of the evaluation process.

Proposals will be evaluated using the following criteria:

List of Criteria	Score
Expertise and experience of the key personnel in the area of work for which they are responsible	20
Quality of the proposal, including unique approaches that might expedite the study and or increase oil recovery and number of pools to which the results can be applied	20
Approach to well and facility design materials selection for CO_2 flooding, knowledge of CO_2 recycle and cost estimation	20
WCSB production & geological experience knowledge	10
Corporate experience and key personnel experience in CO_2 EOR, reservoir modelling and other relevant areas	10
Corporate and key personnel experience with waterflood and miscible flood simulation studies.	10
Corporate tools (e.g. numerical simulators, other) and access to pool and other data	5
Resources to complete the work within the required time frame	5
Total Possible Points	100

Vendors with the highest scores may be invited to make a presentation to the Evaluation Team and references may be checked. The results of the presentations and reference checks will be used by the Evaluation Team to revise the scores.

If a Contract is awarded as a result of this RFP, it will be offered to the Vendor with the highest revised score. In the event of a tie, the Evaluation Team will develop and apply a suitable tie-breaking mechanism.

2.8 Proposed Schedule of Events

RFP Issue Date	June 19, 2007
RFP Close Date	July 16, 2007, 4:30 pm, Alberta Time

The above dates are subject to change at the sole discretion of Alberta Advanced Education & Technology.

3. VENDOR PROPOSAL GUIDELINES

3.1 General Information

Proposals that do not include the proper required documents as listed in section 2.6 shall be deemed non-compliant.

Vendors may respond to this RFP as a single Vendor or as a Consortium.

If the Proposal is from a Consortium, the Proposal cover sheet in Appendix "B" must be used, and each member of the Consortium must sign and date the cover sheet.

Vendors may request a Word version of the Proposal form from the Contracting Administrator, but must not adjust the formatting in any way. Forms must be typed or computer generated.

3.2 Proposal Submission and RFP Closing

Proposals must be received by Alberta Advanced Education & Technology on or before 4:30 p.m. Alberta Time on July 16, 2007 (the "Closing Date"). For RFP closing purposes, the official time of receipt of Proposals shall be as determined by the clock used by the Contracting Administrator to time and date stamp the Proposals.

Vendors may amend or withdraw their Proposal prior to the RFP Closing Date and time by submitting a clear and detailed written notice to the Contracting Administrator. Proposals become irrevocable after the RFP Closing Date.

In either of the following circumstances:

a) the Vendor has rescinded a Proposal prior to the RFP closing date and time; or
b) Alberta Advanced Education & Technology has received the Proposal after the RFP closing date and time;

Such Proposal will, at the Vendor's choice, either be returned to the Vendor at the Vendor's expense after the RFP closing date and time, or destroyed by Alberta Advanced Education & Technology after the RFP closing date and time.

In responding to this RFP:

(a) The RFP cover page must be completed, signed by the Vendor and included in the Proposal.
(b) Proposals received unsigned or after the RFP Closing Date will be rejected.
(c) Ambiguous, unclear or unreadable Proposals may be cause for rejection.
(d) Proposals should be sealed and clearly marked with the RFP number and Closing Date and addressed as follows:

    Attention: Susan Emilsson
    Alberta Energy Research Institute,
    Suite 2540, 801 6th Avenue SW
    Calgary, AB T2P 3W2
    Susan.emilsson@gov.ab.ca

(e) Submit three signed print versions of the Proposal

Proposals submitted electronically or by fax will be accepted so long as the required three print versions of the Proposal and all other related material are received on or before 4:30 p.m., Alberta Time, July 16, 2007. In the event of discrepancies between the print version and the electronic version, **the version received first will govern.**

Alberta Advanced Education & Technology is not responsible for technical failures that may result in the Proposals not being received prior to the dates and times noted above.

4. PROPOSAL EVALUATION PROCESS AND SEQUENCE

The Evaluation Procedure consists of the following three phases:

4.1 Phase One

The Evaluation Team determines whether the Vendor has fully met the evaluation criteria. Evaluation of the quality of content is the focus of Phase Two. **If a Proposal does not meet all of the evaluation criteria in Phase One, then it will not be evaluated further.**

4.2 Phase Two

- Evaluation Team members score the Proposals using the evaluation criteria listed in section 2.8, ***prior to meeting as a team.***
- The individual scores are compared and discussed when the Evaluation Team meets.

- A final team score for each criterion is agreed upon, either through consensus, or through a calculation of the average score.
- The Proposals with the highest final scores for Phase Two will be short-listed and considered for Phase Three

4.3 Phase Three

- High-ranking Vendors will be invited to make a presentation to the Evaluation Team.
- References may be contacted in order to assess the Vendor's suitability for a Contract.
- Based upon the additional information provided, the Evaluation Team will revise the consensus scores

If any Contract is offered as a result of this RFP, the Vendor with the highest final score will be invited to negotiate a Contract.

Alberta Advanced Education & Technology reserves the right to not award a Contract if no Proposal receives a minimum of 60% of the available points. It also reserves the right to refuse to offer a Contract to a Vendor should a reference check prove unfavorable in the opinion of the Evaluation Team.

Subject to the requirements of the *FOIP Act*, discussed below, such scores, described above, shall be confidential, and no totals or scores of such ratings shall be released to any other party.

5. RFP ADMINISTRATION TERMS AND CONDITIONS

5.1 Stipulations

Alberta Advanced Education & Technology reserves the right to cancel this RFP at any time and to reissue it for any reason whatsoever, without incurring any liability and no Vendor will have any claim against Alberta Advanced Education & Technology as a consequence.

Alberta Advanced Education & Technology is not bound to accept the Proposal that provides the lowest price quote, nor any Proposal of those submitted.

Pricing quoted shall be in Canadian dollars and exclusive of the Goods and Services Tax and Harmonized Sales Tax.

A Proposal submitted in response to the RFP constitutes an offer and will proceed to a Contract only if Alberta Advanced Education & Technology accepts the Proposal.

Alberta Advanced Education & Technology reserves the right to request further information from interested Vendors as required, and at the Vendor's expense.

5.2 The Contract

The Contract to be entered into between the successful Vendor and Alberta Advanced Education & Technology shall be negotiated by Alberta Advanced Education & Technology. If, in Alberta Advanced Education & Technology's opinion, it appears that the negotiations will not result in a Contract with the preferred Vendor within thirty (30) days, negotiations with other Vendors submitting Proposals may be undertaken.

This RFP and the Proposal shall form part of the Contract. In the case of conflicts, discrepancies, errors or omissions among this RFP, the Proposal and the Contract, the documents and amendments to them shall take precedence and govern in the following order:

(a) Contract
(b) RFP
(c) Proposal

Claims made in the Proposal will constitute contractual warranties. Any provisions in the Proposal may be included in the Contract as a direct provision thereof

5.3 Confidentiality

5.3.1 Confidentiality and Security of Information

The Vendor shall:

(a) keep strictly confidential all information concerning Alberta Advanced Education & Technology and/or third parties, or any of the business or activities of Alberta Advanced Education & Technology and/or third parties acquired as a result of participation in this RFP;
(b) only use, copy or disclose such information as necessary for the purpose of submitting a Proposal or upon written authorization of Alberta Advanced Education & Technology; and
(c) Maintain security standards, including control of access to data and other information, consistent with the highest standards of business practice in the industry.

5.3.2 FOIP and Collection of Personal Information

The purpose of collecting the Personal Information requested in this RFP is to enable Alberta Advanced Education & Technology to ensure the accuracy and reliability of the Proposal, to enable Alberta Advanced Education & Technology to evaluate the Vendor's response to this RFP and to fulfill other related program purposes of Alberta Advanced Education & Technology. Authority for this collection is section 33(c) of *FOIP*.

FOIP applies to all information and records relating to, or obtained, generated, created, collected or provided under, the RFP and/or the Contract and which are in the custody or control of Alberta Advanced Education & Technology.

All documents submitted to Alberta Advanced Education & Technology are governed by the access and privacy provisions of *FOIP*. While *FOIP* allows persons a right of access to records in Alberta Advanced Education & Technology's custody or control, it also prohibits Alberta Advanced Education & Technology from disclosing Personal Information or confidential business information. This prohibition takes effect if disclosure would be significantly harmful to a Vendor's business interests or would be an unreasonable invasion of personal privacy as defined in sections 16 and 17 of the Act. Vendors are encouraged to identify those portions of their submissions which they are submitting in confidence and which, if revealed, would harm the business interests of the Vendor.

Evaluation criteria and process for this RFP are public information. Individual assessments of Vendors are considered confidential and of interest to competitors or other Vendors under this RFP. Individual assessment information will be provided, upon request, to the Vendor to whom it relates, and to others, only in accordance with *FOIP*. Information regarding *FOIP* procedures is available on the web at http://www.gov.ab.ca/foip.

5.3.3 Protection of Privacy

FOIP imposes an obligation on Alberta Advanced Education & Technology, and through the RFP and related Contract, on the Vendor, to protect the privacy of individuals to whom information relates.

The Vendor will meet the standards set by the requirements of Part 2 of *FOIP*, for all Personal Information the Vendor has access to, collects or uses, discloses or destroys as a consequence of carrying out obligations under the contract.

By submitting Personal Information, the Vendor consents and shall obtain the consent of the Vendor's Resources to its disclosure for the purposes, stated in section 5.3.2, to verify professional standing and to conduct reference checks, if needed.

All costs associated with meeting the Vendor's requirements of *FOIP* as set out in this RFP and the Contract will be borne by the Vendor.

5.4 Period of Commitment

Proposals shall be final and binding on the Vendor for 90 days from the RFP's Closing date and time and may not be altered by subsequent offerings, discussions, or commitments unless the Vendor is requested to do so by Alberta Advanced Education & Technology.

5.5 Subcontracting

The Vendor may subcontract only upon written approval from Alberta Advanced Education & Technology, such approval not to be unreasonably withheld.

5.6 Computers, Software, Parking, Secretarial Services, Travel, Expenses and Insurance

The successful Vendor:

- Will provide their own office space, equipment, computers, software, telephone and photocopy facilities as required, and other tools as necessary for the purpose of performing the Services. Amenities, including but not limited to secretarial services and parking, will not be provided. Onsite equipment, computers, software, telephone and photocopy facilities may be available for use when the work requires face-to-face collaboration at an Alberta Advanced Education & Technology office location.

- May be required to provide evidence of a valid security clearance check, normally a background and criminal records check, on the Vendor, if the Vendor is an individual, or on any or all of the Vendor's employees, agents or subcontractors that may be providing the services, prior to a contract being executed. Alberta Advanced Education & Technology will be under no obligation to enter into any Contract with a Vendor if, in the opinion of Alberta Advanced Education & Technology, acting reasonably, the results of such a security clearance check is not satisfactory.
- May be required to travel to meet contractual requirements and may be expected to attend occasional project meetings at their own expense.
- Must submit expense invoices to be reimbursed for approved expenses incurred while delivering the Services. The expense invoices must contain the Pre-qualified Vendor's name, Contract number, total expense, and attach actual receipts.
- Are required, at their own expense, to obtain insurance under a contract of General Liability Insurance in accordance with the Alberta *Insurance Act* in an amount not less than **$2,000,000** inclusive per occurrence insuring against bodily injury, personal injury, and property damage including loss of use thereof. Evidence of such insurance in a format acceptable to Alberta Advanced Education & Technology shall be made available to Alberta Advanced Education & Technology, at Alberta Advanced Education & Technology's request, as a condition of any Contract(s).

5.7 Proposal Expenses

The Vendor is responsible for all costs of:

- preparing the Proposal
- attending an interview if applicable, and
- For subsequent negotiations, if any, with Alberta Advanced Education & Technology.

5.8 Agreement on Internal Trade

This RFP is subject to Chapter 5 of the *Agreement on Internal Trade.*

5.9 Copyright

All Deliverables produced by the Vendor under the Contract shall become the property of the Crown in Right of Alberta. The Vendor will also waive all moral rights to the Deliverables.

5.10 Conflict of Interest

Vendors must fully disclose in writing to the Contracting Administrator on or before the closing date of this RFP, the circumstances of any possible conflict of interest or what could be perceived as a possible conflict of interest if the Vendor were to become a contracting party pursuant to this RFP. Alberta Advanced Education & Technology shall review any submissions by Vendors under this provision and may reject any Proposals where, in the opinion of Alberta Advanced Education & Technology, the Vendor could be in a conflict of interest or could be perceived to be in a possible conflict of interest position if the Vendor were to become a contracting party pursuant to this RFP

5.11 Proposal Returns

Proposals and accompanying documentation submitted by the Vendors are the property of Alberta Advanced Education & Technology and will not be returned. The Proposals and accompanying documentation shall be retained in accordance with Alberta Advanced Education & Technology's records management policies and regulations.

5.12 Vendor Debriefing

Alberta Advanced Education & Technology will, at the request of an unsuccessful Vendor who responded to this RFP, conduct a debriefing for the purpose of informing the Vendor as to why their Proposal was not selected.

5.13 Questions

All questions regarding the RFP must be directed to the Contracting Administrator, in writing. Enquiries and responses will be recorded and may, at the Minister's discretion, be distributed to all Vendors.

The Vendor is responsible for notifying the Contracting Administrator in writing of any ambiguity, divergence, error, omission, oversight, or contradiction, or item subject to more than one interpretation in the RFP, as it is discovered, and to request any instruction, decision, or direction required to prepare the Proposal.

In order for Alberta Advanced Education & Technology to deal effectively with Vendor questions or concerns about any term, condition or requirements of this RFP, such questions or concerns must be communicated in writing to the Contracting Administrator on or before July 12, 2007 4:30 p.m., Alberta Time. Questions received after this time will be answered if time permits.

Verbal responses to enquiries are not binding on any party.

Questions may be directed to Dr. Surindar Singh, e-mail at surindar.singh@gov.ab.ca .

5.14 Contact Information

For further information, contact:

Dr. Surindar Singh
Senior Research Manager, CO_2 Management
Alberta Energy Research Institute
Alberta Advanced Education & Technology
6th Floor, Phipps-McKinnon Building,
Suite 500, 10020 - 101A Ave NW,
Edmonton, Alberta T5J 3G2.
Phone (780) 422 0046

E-mail: surindar.singh@gov.ab.ca

- **APPENDIX A: VENDOR PROPOSAL COVER SHEET**

Alberta Energy Research Institute
25th Floor, AMEC Place
801 - 6 Avenue S.W.
Calgary, Alberta, T2P3W2

CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta

	Opportunity Number: AERI007 **RFP Issue Date**: June 19, 2007 **RFP Closing**: 4:30 pm Alberta Time, July 16, 2007 **Contracting Administrator**: Susan Emilsson **Fax**: (403) 297 3638 **E-mail**: susan.emilsson@gov.ab.ca

Vendors may obtain this document directly from the Contracting Administrator **Facsimile or digital Proposals (i.e., Word 2000 or PDF format for text) will be accepted, however, the required THREE (3) print versions must also be sent. All materials and copies of the Proposal must be received by the RFP Closing prescribed above.**

Vendors must sign and return this cover page with their Proposal.

Enclosed is my Proposal to this Request for Proposals. The Vendor consents, and has obtained written consent of any individuals identified in the Proposal, to the use of the information in the Proposal by Alberta Advanced Education & Technology; Alberta Advanced Education & Technology's employees, subcontractors and agents, to evaluate the Proposal and use this information for other program purposes of Alberta Advanced Education & Technology.

Vendor Name (if different than Authorized Signature below)	vendor Address
Telephone	Facsimile
Authorized Signature	(Print Name)
Title (if applicable)	Date

Vendors must accept the administration terms and conditions of the RFP by completing the following statement.

I, ____________________ (sign name), ❑ (check box) accept the Administration Terms and Conditions in **Section 5** of this Request for Proposals.

▪ **APPENDIX B: CONSORTIUM PROPOSAL COVER SHEET**

Alberta Energy Research Institute
25th Floor, AMEC Place
801 - 6 Avenue S.W.
Calgary, Alberta, T2P3W2

CO_2 Enhanced Hydrocarbon Recovery (EHR): Incremental Recovery and CO_2 Storage Potential in Alberta

	Opportunity Number: AERI007 **RFP Issue Date**: June 19, 2007 **RFP Closing**: 4:30 pm Alberta Time, July 16, 2007 **Contracting Administrator**: Susan Emilsson **Fax**: (403) 297 3638 **E-mail**: susan.emilsson@gov.ab.ca

Vendors may obtain this document directly from the Contracting Administrator
Facsimile or digital Proposals (i.e., Word 2000 or PDF format for text) will be accepted, however, the required THREE (3) print versions must also be sent. All materials and copies of the Proposal must be received by the RFP Closing prescribed above.

Vendors must sign and return this cover page with their Proposal.

Enclosed is my Proposal to this Request for Proposals. The Vendor consents, and has obtained written consent of any individuals identified in the Proposal, to the use of the information in the Proposal by Alberta Advanced Education & Technology; Alberta Advanced Education & Technology's employees, subcontractors and agents, to evaluate the Proposal and use this information for other program purposes of Alberta Advanced Education & Technology.

______________________	______________________
Prime Vendor Name	Vendor Address
______________________	______________________
Telephone	Facsimile
______________________	______________________
Authorized Signature	(Print Name)
______________________	______________________
Title (if applicable)	Date

Vendors must accept the administration terms and conditions of the RFP by completing the following statement.

I, ____________________ (sign name), ❑ (check box) accept the Administration Terms and Conditions in **Section 5** of this Request for Proposals.

RFP # NUMBER
Consortium Proposal Cover Sheet – Page 2

Vendor Name	Vendor Address
Telephone	Facsimile
Authorized Signature	(Print Name)
Title (if applicable)	Date

Vendors must accept the administration terms and conditions of the RFP by completing the following statement.

I, ____________________ (sign name), ❑ (check box) accept the Administration Terms and Conditions in **Section 5** of this Request for Proposals

Vendor Name	Vendor Address
Telephone	Facsimile
Authorized Signature	(Print Name)
Title (if applicable)	Date

Vendors must accept the administration terms and conditions of the RFP by completing the following statement.

I, ____________________ (sign name), ❑ (check box) accept the Administration Terms and Conditions in **Section 5** of this Request for Proposals

Please Note: Vendors must add signature lines to accommodate all Vendors in a Consortium.

▪ APPENDIX C: TABLES

	Table 1A - Horizontal Miscible				
#	Field	Pool	Type	Field	Pool #
1	Alderson	UMnv WW & LMnv QQ	W / F	43	250360
2	Ante Creek	Beaverhill Lake	S / F	55	744000
3	Bonanza	Boundary A	W / F	153	510001
4	Bonnie Glen	D-3 A		151	720001
5	Caroline	Rundle A	W / F	194	610001
6	Carrot Creek	Cardium F	W / F	196	176006
7	Carson Creek North	Beaverhill Lake A & B	W / F	200	744060
8	Cranberry	Slave Point D	W / F	263	758004
9	Crystal	Viking A	W / F	241	218001
10	Cyn-Pem	Cardium A	W / F	271	176001
11	Cyn-Pem	Cardium D	W / F	271	176004
12	Drumheller	D-2 A		292	696001
13	Drumheller	D-2 B		292	696002
14	Enchant	Arcs J & VV	W / F	336	694164
15	Evi	Keg River A & Granite Wash N		353	788660
16	Evi	Keg River B & Granite Wash P		353	788661
17	Fenn West	D-2 A		373	696001
18	Fenn-Big Valley	D-2 A	Prim	371	696001
19	Ferrier	Belly River Q, Cardium G & L	W / F	377	126160
20	Gift	Slave Point A	W / F	322	758001
21	Golden	Slave Point A		423	758001
22	Goose River	Beaverhill Lake A	W / F, S/F	425	744001
23	Grand Forks	Upper Mannville K	W / F	430	250011
24	Harmattan East	Rundle	W / F	448	610000
25	Hays	Lower Mannville A	W / F	456	310001
26	Joarcam	Viking	W / F	503	218000
27	Joffre	D-2	W / F	505	696000
28	Joffre	Viking	W / F, S/F	505	218000
29	Johnson	Glauconitic B	W / F	504	300002
30	Judy Creek	Beaverhill Lake A	W / F, S/F	509	744001
31	Judy Creek	Beaverhill Lake B	W / F, S/F	509	744002
32	Kaybob	Beaverhill Lake A	W / F, S/F	513	744001
33	Leduc-Woodbend	D-2 A	W / F	551	696001
34	Manyberries	Sunburst Q	W / F	595	332017
35	Medicine River	Glauconitic A & Ostracod CC	W / F	604	300562
36	Meekwap	D-2 A	W / F	605	696001
37	Mitsue	Gilwood A	W / F, S/F	615	778001
38	Morinville	D-3 B		620	720002
39	Nipisi	Gilwood A	W / F, S/F	644	778001
40	Otter	Granite Wash A		324	976001
41	Panny	Keg River D		734	788004
42	Pembina	Basal Belly River B & F	W / F	685	126062
43	Pembina	Cardium	W / F	685	176000

44	Pembina	Nisku II		685	696035
45	Pouce Coupe South	Boundary B	W / F	729	510002
46	Provost	Dina S		750	322019
47	Provost	Dina Y		750	322025
48	Provost	Ellerslie N & OOO		750	336060
49	Rainbow	Keg River F	S / F	753	788006
50	Rainbow	Keg River OO	W / F	753	788041
51	Rainbow	Muskeg C	W / F	753	782003
52	Rainbow	Sulphur Point B	W / F	753	781002
53	Rainbow South	Muskeg H	W / F	754	782008
54	Redwater	D-3		770	720000
55	Rycroft	Halfway C	W / F	802	516003
56	Seal	Slave Point A		827	758001
57	Simonette	Beaverhill Lake A	W / F	844	744001
58	Simonette	Beaverhill Lake B	W / F	844	744002
59	Slave	Slave Point H		839	758008
60	Slave	Slave Point S		839	758019
61	Snipe Lake	Beaverhill Lake	W / F	856	744000
62	Sturgeon Lake	D-3		874	720000
63	Sturgeon Lake South	D-3		876	720000
64	Swan Hills	Beaverhill Lake A&B	W / F, S/F	887	744060
65	Swan Hills South	Beaverhill Lake A&B	S / F	889	744060
66	Turin	Upper Mannville H	W / F	911	250008
67	Valhalla	Montney C & LL	W / F	920	524063
68	Virginia Hills	Beaverhill Lake	W / F, S/F	925	744000
69	Wayne-Rosedale	Nisku A		935	696001
70	Youngstown	Arcs		996	694000

Table 1B - Horizontal Immiscible					
#	**Field**	**Pool**	**Type**	**Field**	**Pool #**
1	Alderson	Lower Mannville B	W / F	43	310002
2	Bellshill Lake	Ellerslie A		115	336001
3	Bow Island	Sawtooth U		160	428021
4	Cecil	Charlie Lake JJ		204	508036
5	Chauvin South	Mannville Mu #1	W / F	212	248060
6	Chauvin South	Sparky H	W / F	212	276008
7	Chin Coulee	Glauconitic C & BMnv A	W / F	217	301360
8	Countess	Upper Mannville O	W / F	259	250015
9	Enchant	Ellis L		336	418012
10	Glenevis	Banff		416	644000
11	Grand Forks	Lower Mann K & V	W / F	430	310060
12	Grand Forks	Sawtooth MM	W / F	430	428039
13	Grand Forks	Sawtooth O		430	428015
14	Grand Forks	Sawtooth OO	W / F	430	428041
15	Grand Forks	Sawtooth T		430	428020
16	Grand Forks	Upper Mannville B	W / F	430	250002
17	Harmattan-Elkton	Rundle C	W / F	450	610003
18	Hays	Sawtooth B		456	428002

19	Hayter	Dina A	W / F	457	322001
20	Hayter	Dina B		457	322002
21	Hayter	Dina I		457	322009
22	Horsefly Lake	Mannville	W / F	475	248000
23	Jenner	Upper Mannville F		500	250006
24	Killam	Glauconitic FF		524	300032
25	Provost	Basal Quartz C		750	334003
26	Provost	Blairmore		750	244000
27	Provost	Blairmore B		750	244002
28	Provost	Cummings I	W / F	750	302009
29	Provost	Cummings S		750	302019
30	Provost	Dina A		750	322001
31	Provost	Dina G4G		750	322233
32	Provost	Dina N		750	322014
33	Provost	Dina O		750	322015
34	Provost	Dina Q		750	322017
35	Provost	Dina YY		750	322051
36	Provost	Glauconitic A		750	300001
37	Provost	Lloydminster DD	W / F	750	294030
38	Provost	Lloydminster KK		750	294037
39	Provost	Lloydminster O	W / F	750	294015
40	Provost	Lloydminster X & Cummings N	W / F	750	294260
41	Provost	Mannville L		750	248012
42	Provost	Sparky D	W / F	750	276004
43	Redwater	Basal Mannville H		770	320008
44	Ronalane	Sawtooth B		792	428002
45	Stettler	D-2 A	W / F	866	696001
46	Stettler	D-3 A		866	720001
47	Suffield	Upper Mannville D	W / F	877	250004
48	Suffield	Upper Mannville J	W / F	877	250010
49	Suffield	Upper Mannville U	W / F	877	250021
50	Suffield	Upper Mannville YYY	W / F	877	250725
51	Taber	Glauconitic K	W / F	893	300011
52	Taber	Taber N	W / F	893	346014
53	Taber	Taber Q & Sawtooth		893	346260
54	Taber North	Taber C		894	346003
55	Taber South	Mannville A	W / F	895	248001
56	Taber South	Mannville B	W / F	895	248002
57	Valhalla	Doe Creek I	W / F	920	190009
58	Valhalla	Doe Creek T,U & BB	W / F	920	190061
59	Vermilion	Sparky A	W / F	921	276001
60	Viking-Kinsella	Sparky E	W / F	923	276005
61	Viking-Kinsella	Sparky JJ	W / F	923	276036
62	Viking-Kinsella	Upper Mannville Z3Z	W / F	923	251126
63	Virginia Hills	Belloy A	W / F	925	556001
64	Wainwright	Wainwright & Sparky Z	W / F	928	278160
65	Wainwright	Wainwright B	W / F	928	278002

#	Table 1C - Gas Cap Pools				
#	Field	Pool	Type	Field	Pool #
1	Acheson	D-3 A	W / F	9	720001
2	Beauvallon	Colony K		105	256011
3	Belloy	Debolt A,B,C,D,E &		113	612060
4	Bigoray	Pekisko A		126	642001
5	Blueridge	Pekisko A		148	642001
6	Boundary Lake South	Triassic G		157	500007
7	Campbell-Namao	Blairmore A		185	244001
8	Campbell-Namao	Blairmore J		185	244010
9	Carbon	Belly River,Viking, Mann & Rundle Mu #1		190	219260
10	Carbon	Glauconitic J & S		190	300060
11	Caroline	Basal Mannville Mu #3		194	320066
12	Caroline	First White Specks & Viking A		194	214260
13	Cessford	Basal Colorado A	W / F	206	242001
14	Cessford	Mannville C	W / F	206	248003
15	Cessford	Mannville Y & Z		206	248061
16	Cherhill	Banff H		213	644008
17	Chickadee	Upper Mannville D & Gething D		235	251060
18	Crossfield	Rundle B		267	610002
19	Dunvegan	Debolt & Elkton Mu #1		300	612060
20	Edson	Viking, Mannville & Jurassic Mu #1		320	220360
21	Ferrybank	Belly River C,G & H	W / F	378	126060
22	Fox Creek	Viking,Umnv & Gething Mu #1		395	326260
23	Garrington	Cardium, Viking & Manv Mu #1	W / F	405	177460
24	Garrington	Mannville & Rundle Mu #1		405	248960
25	Garrington	Wabamun A		405	658001
26	Ghost Pine	Upper & Lower Mannville Mu #1		408	250361
27	Ghost Pine	Upper Mannville Q,Y,Ff & T3T		408	250064
28	Gilby	Basal Mannville A & Jurassic D		412	320160
29	Gilby	Mannville,Jurassic Rundle Mu #1		412	320360
30	Greencourt	Jurassic A & Pekisko A		431	446560
31	Harmattan East	Viking E	W / F	448	218005
32	Homeglen-Rimbey	D-3		470	720000
33	Hussar	Glauconitic A		486	300001
34	Innisfail	D-3		494	720000
35	Joarcam	Viking C		503	218003
36	Judy Creek	Viking A		509	218001
37	Kaybob	Viking O & Gething		513	222363
38	Kaybob South	Triassic A	W / F	514	500001
39	Kaybob South	UMnv D,Gething O2O Triassic B		514	254860
40	Knopcik	Halfway N & Montney A		536	516560
41	Leduc-Woodbend	D-3 A	W / F	551	720001
42	Lone Pine Creek	D-3 A		576	720001
43	Long Coulee	Glauconitic F		577	300006
44	Long Coulee	Glauconitic I & Sunburst G		577	303160
45	Medicine River	Basal Quartz LL		604	334038

46	Minehead	Belly River A, Cardium C & F		646	126160
47	Morgan	Sparky A,Rex A, Lloyd A & Dina B		619	277060
48	Nevis	Devonian & D-2 C		636	650060
49	Niton	Basal Quartz A & Rock Creek F	W / F	650	334461
50	Niton	Basal Quartz I & Rock Creek A		650	334460
51	Paddle River	Jurassic-Detrital & Rundle		672	450200
52	Pembina	Card, Vik, Mannville Jurassic Mu #1		685	178160
53	Pembina	Cardium Z, Viking G Ellerslie II		685	178460
54	Provost	UMnv E2E,Lmnv Ff & Viking M3M		750	220960
55	Provost	Upper Mannville U8U		750	251947
56	Provost	Viking,Belly River Manv Mu #1	W / F	750	218060
57	Rainbow	Keg River A	S / F	753	788001
58	Red Rock	Chinook, Ft St.John & Bullhead Mu #1		769	154160
59	Redwater	Up-Mid-Low Viking A		770	218760
60	Ricinus	Cardium A	G / F	785	176001
61	Ricinus	Cardium L		785	176012
62	Rowley	Pekisko A		798	642001
63	Simonette	Dunvegan F		844	192006
64	Suffield	Upper Mannville A		877	250001
65	Sylvan Lake	Elkton-Shunda B & Pekisko N		891	639360
66	Turner Valley	Rundle	W / F	909	610000
67	Twining	UMnv O,Lmnv A & Rundle A		913	248960
68	Viking-Kinsella	Viking & Mannville Mu #1		923	219160
69	Viking-Kinsella	Wainwright B	W / F	923	278002
70	Wainwright	Viking & Mannville Mu #1		928	219160
71	Waskahigan	Dunvegan C		930	192003
72	Wayne-Rosedale	Viking,Upper & Lowe Mannville Mu #2		935	220961
73	Wembley	Doig E		948	520005
74	Wembley	Halfway B	W / F	948	516202
75	Westerose	D-3		941	720000
76	Westerose South	D-3 A		943	720001
77	Willesden Green	Belly River,Card A Viking Mu #1	W / F	967	176760
78	Willesden Green	Glc A,C, Elrs D,G & JJ	W / F	967	300260
79	Wilson Creek	Mannville,Jurassic & Rundle Mu #1		973	249860
80	Wimborne	D-3 A		976	720001
81	Windfall	D-3 A		979	720001
82	Wintering Hills	Upper Mannville A & Ellerslie A		982	336460