Assessment of Innovative Applications of Electricity for Oil Sands Development
Phase 1 Report

Prepared For

Petroleum Technology Alliance Canada (PTAC)

June 2012

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By Jacobs Consultancy

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1.0 Executive Summary

Jacobs Consultancy Canada Inc. ("Jacobs Consultancy") was engaged by the Petroleum Technology Alliance of Canada ("PTAC") to evaluate the technical-economic prospects of applying novel electricity-based technologies to:

- Steam-assisted gravity drainage (SAGD)-based bitumen production,
- Bitumen upgrading, and
- Other emerging technologies for in situ bitumen production from oil sands.

This initial phase of the Study (the "Study") was, per plan, a screening level study. The goal of the screening process was to determine if any of the technologies selected for evaluation are worthy of a more in-depth technical-economic analysis to justify future investment. We agreed with PTAC that these screening-level comparisons were to be based on public domain data and in-house Jacobs Consultancy knowledge and information.[1]

The Study was partitioned into three phases:

- Phase 1 - Literature Search and Semi-Quantitative Screening
- Phase 1B - Techno-Economic Analysis of Selected Technology Applications (Optional and not addressed in this report)
- Phase 2 - Additional Technology Analysis Work (Optional and not addressed in this report)

We report here the outcomes of Phase 1, a screening review of potential technologies for novel applications of electric power to bitumen production and upgrading.

1.1 Work Scope and Methodology

Evaluation Criteria

We compared each selected SAGD and bitumen upgrading technology to an appropriate base case on the basis of:

- Estimated capital costs

[1] The project schedule and budget did not allow for extensive vendor contact and development of information non-disclosure agreements to allow review and use of confidential supplier information.

- Estimated operating costs
- Estimated greenhouse gas emissions
- Observations regarding technical feasibility
- Effects on process yields
- Need and timing for process development
- Potential regulatory issues
- Unit operability and facility availability risk

Because the emerging technologies for electrical in situ bitumen production are at a much earlier stage of development, sufficient details were not available for us to apply our detailed evaluation criteria. Instead, for these technologies we developed a qualitative assessment of the state of technology development, the organizations involved, and the prospects for continued progress toward commercialization.

Technology Selection

Some of the screened electricity-based technologies for SAGD and bitumen upgrading were suggested by PTAC members. The rest of the screened technologies were the result of a technology application brainstorming session we conducted with our colleagues in Jacobs Consultancy. PTAC and Jacobs Consultancy agreed on a final slate of technologies to screen before the actual information gathering and screening process began. For the electrical in-situ bitumen production from oil sands, we were asked to focus on companies and technologies that are focused on oil sands, versus carbonate formations.

SAGD Technologies

The eight electricity-based technologies and applications that were selected and evaluated for SAGD processing are:

- Central Processing Facility (CPF) electric boilers (SAGD-1)
- CPF steam compressors to reuse low-pressure steam (SAGD-1A)
- Electric boilers at the well pads to reuse condensate (SAGD-2)
- Well pad steam compressors to reuse condensate (SAGD-3)
- Steam superheaters to reduce condensate formation (SAGD-4)

- Reverse Osmosis (RO) make-up water treatment (SAGD-5)
- Mechanical Vapor Compression (MVC) evaporators (SAGD-6)
- Zero Liquid Discharge (ZLD) facilities (SAGD-7)

Upgrading Technologies

The seven technologies that were selected and evaluated for bitumen upgrading are:

- Hydrogen production via electrolysis of water (UG-1)
- Electric heaters and reboilers[2] (UG-2)
- Electric hot oil heating systems (UG-3)
- Heat pumps (UG-4)
- Vacuum compressors (UG-5)
- Oxygen enrichment of fired heaters[3] (UG-6)
- Flexicoking™ (UG-7)

Electrical In Situ Bitumen Production

As agreed with PTAC, we focused on emerging technologies for oil sands applications versus carbonate formations. The two technologies selected for qualitative assessment are:

- ET-DSP, a bitumen production process that is based on resistance heating. This technology is under development by ET-Energy of Alberta.
- ESEIEH, a bitumen production process that is based on dielectric heating and is under development by the ESEIEH consortium.

[2] The main applications will be within the DRU (steam flash drums) and the mild hydrocracker (stripper columns and reactor loop).
[3] For flue gas combustion heaters

1.2 Study Outcomes for SAGD and Upgrading

Relative Energy Prices

For both conventional SAGD and conventional upgrading applications, electricity is used most often for prime mover power (e.g., pumps, compressors) and natural gas is used most often as a source of heat (e.g., steam boiler, fired heater for hydrocarbon processing).

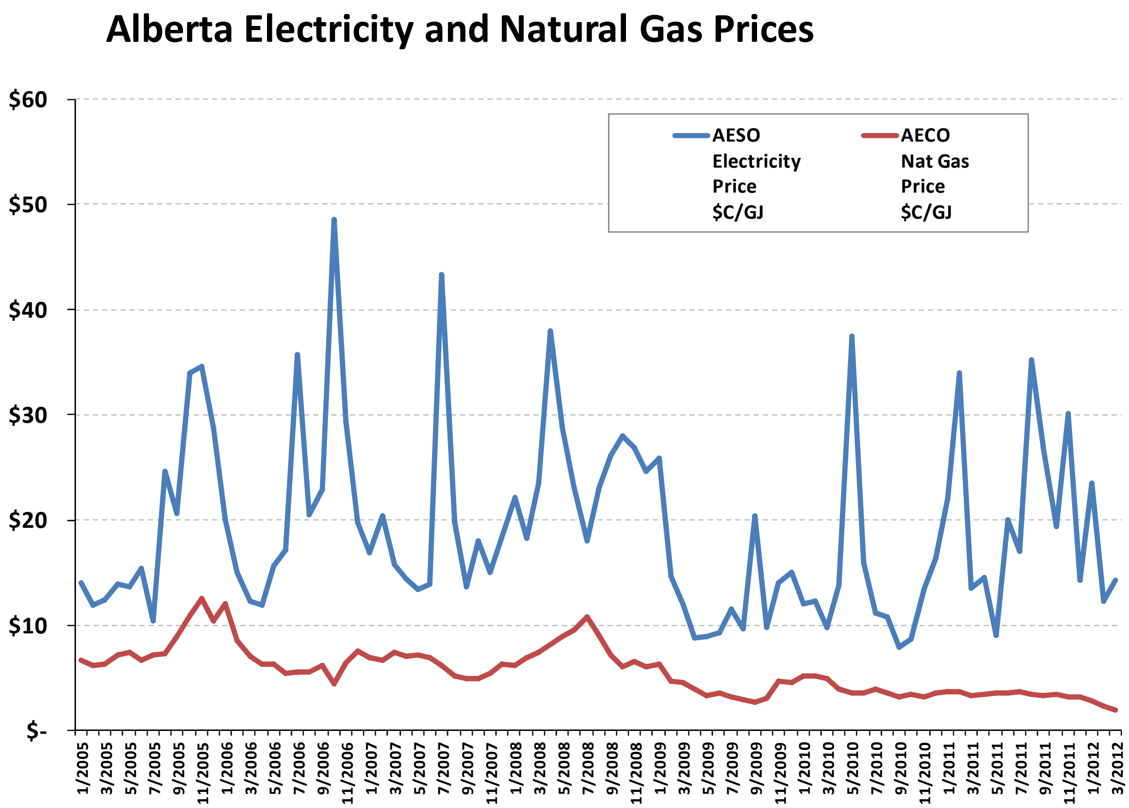
With a few exceptions, the novel applications of electricity that we investigated mainly involved using electricity to replace natural gas for heat (e.g., electrical boiler vs. natural gas boiler) or to replace natural gas heating with a different unit operation (e.g., steam compressor versus steam boiler).

The key to economic feasibility for these technologies is the difference between the cost/value of electricity and the cost/value of natural gas. In Figure 1.1 we present a recent history of electricity and natural gas prices in Alberta. While electrical energy typically is priced on a megawatt hour basis, we converted electricity prices to a gigajoule basis to compare with natural gas prices.

In the figure, we observe that electricity prices vary widely, but on only a few occasions did electricity and natural gas prices approach each other. On a $/GJ basis, the price of natural gas is almost always significantly lower than that of electricity.

Our Study basis prices of $77.20/MW-hr or $21.44/GJ for electricity and $4.38/GJ ($15.77/MW-hr) for natural gas are consistent with this history. Since the novel SAGD and upgrading technologies in the Study increased electricity use and decreased natural gas use, it is not surprising that operating costs increased for these technologies. The one exception was for Flexicoking, where a significant amount of heat is derived from the coke by-product of bitumen upgrading rather than from natural gas.

Figure 1.1
History of Alberta Electricity and Natural Gas Prices

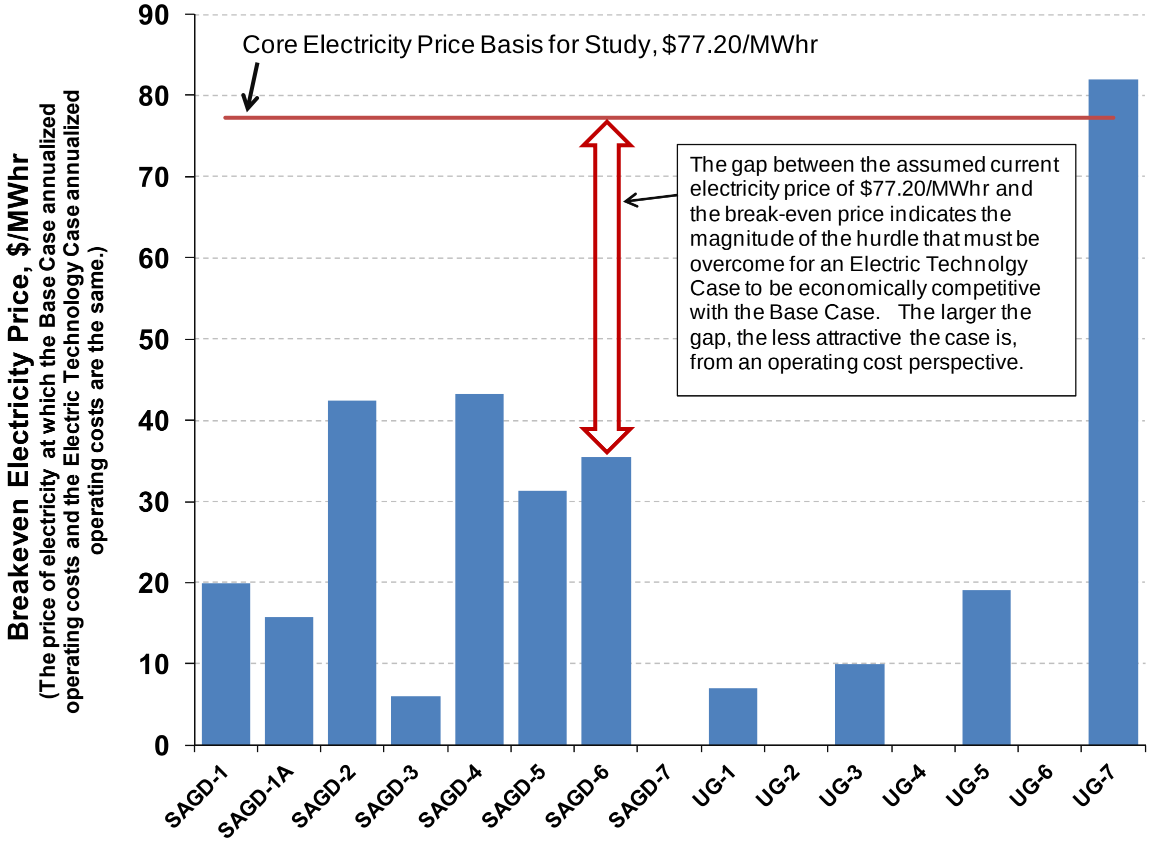


As discussed in this Report, we calculated a "breakeven" price for electricity for each novel technology.

The breakeven price is defined as the price of electricity at which the base case annualized operating costs and the new technology annualized operating costs are the same. In Figure 1.2 we show the breakeven prices for SAGD and upgrading technologies in the Study.

The gap between the actual price of $77.20/MW-hr and the breakeven prices shows the size of the hurdle that must be overcome for the novel technologies to be economically competitive. The gap shows how much power prices in Alberta must fall (at constant natural gas price) to make each technology attractive. We note that Flexicoking, Case UG-7, is unusual insofar as the trade-off is not natural gas for electricity, but natural gas for petcoke. A sample breakeven calculation is shown in Appendix 7.

Figure 1.2
Breakeven Electricity Prices for SAGD and Upgrading Technologies



Most SAGD technology applications are closer to current economics than are the upgrading applications, again with the exception of Flexicoking which benefits from the use of coke by-product.

Other Screening Criteria for SAGD and Upgrading

- Capital Cost: Nearly all of the technologies would increase CAPEX relative to the appropriate base case. A few technologies might have slightly less CAPEX than the appropriate base case.
- Operating Cost: As discussed above, all of the technologies would suffer higher operating costs, except for RO Raw Water Treatment and Flexicoking
- Total Carbon Emissions: All of the technologies except for RO Raw Water Treatment would have higher total carbon emissions, primarily because much of the electricity from the power grid is generated from coal and natural gas.

- Technical, Development, Operability Risks: To varying degrees, all of the technologies would require some combination of process development and testing before commercialization, or would add risk to operability and availability versus current technologies.

Conclusions and Recommendations

We conclude that none of the SAGD or upgrading technologies survive the screening criteria defined for the Study. Lower-cost and lower-emission sources of electricity would affect these outcomes.

If no- or low-carbon emissions electricity became available, at a significantly lower price than today's electricity price (e.g., perhaps, nuclear power), Case SAGD-1 (CPF Electric Boilers), Case 1A (CFP Steam Compressors), Case SAGD-2 (Boilers at Well pad), Case SAGD-3 (Compressors at Well pad), and Case SAGD-4 (Electric Steam Superheaters) might warrant further analysis. (Base Case economics and emissions would improve also.) Regardless, all of these cases have significant commercialization risk because of varying combinations of technical feasibility, process development and availability risk.

Likewise for upgrading, if no- or low-carbon emissions electricity became available, Case UG-5 (Vacuum Compressor) might deserve further analysis. We also recommend a more detailed review of Case UG-3 (Hot Oil System) as there may be capital and operating benefits not recognized in the Study. All these cases probably would require some process development and pilot testing to prove feasibility.

1.3 Emerging In Situ Bitumen Production

It appears that both the ET-Energy ET-DSP process and the ESEIEH process may have significant potential, especially if low-priced electricity becomes available, or if natural gas prices start trending higher in the future. Both technologies are worthy of some degree of further evaluation, most likely after initial in-field results are available for analysis.

Both technologies also offer the promise of monetization of bitumen reserves that cannot be accessed by either traditional SAGD or mining technology. This makes both technologies attractive in terms of maximizing corporate return on reserve assets.

1.4 What Is in the Rest of this Report?

We organized the details of our Report as follows:

- Section 2 gives the background and objectives of the Study.
- Section 3 provides the Study basis and assumptions.
- Section 4 describes SAGD technologies using electricity.
- Section 5 describes upgrading technologies using electricity.
- Section 6 compares results of the screening process for SAGD and upgrading technologies.
- Section 7 discusses emerging electrical in situ bitumen production.
- Section 8 provides a comprehensive list of terms and acronyms used in the Study.
- The Appendices contain detailed information on methodology and calculations as well as a list of Study references.

2.0 Background and Objectives

2.1 Background

Bitumen is produced by mining or in situ methods in the oil sands regions of Alberta. A common in situ production method is steam-assisted gravity drainage (SAGD). SAGD projects generate high-pressure steam by burning natural gas in once-through steam generators (OTSGs), drum boilers or cogeneration units. This steam is injected into the ground to heat the bitumen and allow pumping it above ground for further processing. This overall process results in measureable processing costs and GHG emissions.

Bitumen upgrading processes require significant quantities of hydrogen, which typically is generated from natural gas. Moreover, significant quantities of bitumen-derived fuel gas and/or natural gas are used to enable separation processes.

It is postulated that the use of electricity for SAGD steam production, to replace steam at the central processing facilities (CPF) or the well pad, or to serve as a source of energy for other energy-intensive unit operations in bitumen production and upgrading could be technically viable and perhaps economically viable under certain conditions. Use of electricity also might reduce direct greenhouse gas (GHG) emissions. Conceivably, lower cost and lower GHG emission electricity could be provided by, for example, large nuclear power plants, thereby reducing the cost of electricity while reducing GHG emissions.

2.2 Objectives

PTAC has established the following overall, long-term objectives for a multi-phase project:

1. Determine the technical-economic feasibility of innovative applications of electricity for sustainable development of oil sands.
2. Evaluate the full life cycle of energy efficiency and GHG impacts for the most promising innovative application(s) of electricity.

Jacobs Consultancy was engaged by PTAC to evaluate electricity-based technologies for:

- SAGD-based bitumen production,
- Bitumen upgrading, and
- Other emerging in-situ bitumen production from oil sands.

This initial Study was a screening level study. The goal of the screening process was to determine if any of the technologies selected for evaluation are worthy of a more in-depth technical-economic analysis to justify future investment. We agreed with PTAC that these screening-level comparisons were to be based on public domain data and in-house Jacobs Consultancy knowledge and information.

The Study was partitioned into three phases:

- Phase 1 - Literature Search and Semi-Quantitative Screening
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We report here the outcomes of Phase 1, a screening review of potential technologies for novel applications of electric power to bitumen production and upgrading.

2.3 Scope of Work

The three technology areas under evaluation are:

1. Use of electrical boilers, steam compressors, and electrical means to heat wet steam near well heads or below ground to higher steam quality. Where electric boilers are reviewed, we considered:
    a. the boiler feed water quality requirement vis-à-vis that being used in OTSGs
    b. the biggest boiler capacity currently in use
    c. the size limitations (e.g., Is modular more appropriate than large-scale? What are economy-of-scale effects?)
    d. can they operate as OTSGs, their efficiency, etc.
2. Opportunities for innovative use of electricity in upgrading, such as stab-in reboilers, electrolysis to produce hydrogen, and other novel approaches in using electricity for oil sands development.
3. Emerging in-situ exploitation technologies using electric and electromagnetic heating of reservoirs, etc.

We agreed to take a staged approach to topic analysis. In this initial project stage, Phase 1, we conducted a high-level screening analysis of the above three technology topics with the goal of identifying and recommending which technologies and applications are worthy of more in-depth techno-economic analysis.

We used high-level, publicly available information in each subject area to:

1. Evaluate the available information, and assess relevance and accuracy
2. Select a group of electrical technology application cases that appear reasonable to evaluate
3. Develop base cases and benchmark capital costs, operating costs and carbon intensity
4. Evaluate the new technology cases, in comparison to appropriate base cases with respect to:
    - Estimated capital costs
    - Estimated operating costs
    - Estimated GHG emissions
    - Opinions regarding technical feasibility
    - Effects on process yields
    - Process development requirements and timing
    - Potential regulatory issues
    - Unit operation and facility availability risks
5. Develop a qualitative technology viability screening technique based on the above measures and rank cases and develop recommendations for the path forward to Phase 1b and Phase 2 (more in-depth analysis as potential future work), as appropriate

The following items are outside the scope of this initial phase of the Study:

- Detailed economic analysis
- Life Cycle GHG emissions estimates
- Quantitative analysis of the selected technologies reviewed

Technology Selection Process

Some of the screened electricity-based technologies for SAGD and bitumen upgrading were suggested by PTAC members. The rest of the screened technologies were the result of a technology application brainstorming session we conducted with our colleagues in Jacobs Consultancy.

PTAC and Jacobs Consultancy agreed on a final slate of technologies to screen before the actual information gathering and screening process began. For the electrical in-situ bitumen production from oil sands, we were asked to focus on companies and technologies that are focused on oil sands, versus carbonate formations.

3.0 Study Basis and Assumptions

A set of base cases for SAGD and bitumen upgrading were developed to provide a frame of reference for the electricity-based technologies that apply directly to SAGD and bitumen upgrading installations. Key technology valuation parameters include project capital costs, facility operating costs and GHG production.

The SAGD facility and upgrading facility base case definitions are consistent with recent installations and upcoming facility configurations that Jacobs Consultancy is familiar with. For key components a range of value is provided, for comparison.

Only those electric in-situ production technologies that are clearly applicable to oil sands bitumen production were considered. Thus, technologies that are focused on carbonates application were not considered.

3.1 Power and Natural Gas Costs Basis Used for Study

PTAC requested that we use 2011 average values for Alberta power prices and best estimates of gate-value natural gas prices. Average 2011 delivered power costs were approximately $77.20/MW-hr. Average 2011 gate prices for natural gas were assumed to be approximately $4.38/GJ. This natural gas SAGD facility or upgrader facility gate price estimate was determined by adjusting average 2011 AECO natural gas prices upward by 25 percent.

[Average 2011 AECO gas price ×1.25 ≈ $4.38/GJ]

3.2 SAGD Facility – Base Case Description

The following basis was used as the comparison point for all technologies that would potentially be added to an Alberta SAGD facility.

- SAGD Facility Capacity: 40,000 BPSD (bitumen) Central Processing Facility (CPF)
- Well Pad Configuration
    - Lift Mechanism: mechanical lift
    - Reservoir Pressure: 3,000 kPag
    - Surface Pressure: 4,800 kPag

  - Subcool[4]: 20°C (Typical range is 10°C to 45°C)
  - GOR: 8:1 (Typical range is 3 to 20)
  - SOR : 3.25 (Typical range is 2.5 to 6)
  - Production per Well Pair: 1,000 BPD
  - Well-pairs per pad: 8
- Central Processing Facility
  - Oil Treating: Free water knock-out (FWKO) and mechanical treaters @ 125°C
  - Water Treating: Warm lime softening (WLS)
  - Steam Generators: OTSG - 80% steam quality
  - Steam Pressure: 12,000 kPag
  - Make-up Water Quality: 10,000 mg/L TDS
  - Produced Water Quality: 2,200 mg/L TDS
- Other Key Assumptions
  - Steam Line Heat Loss
    - Assume 5% of total steam condenses
    - Assuming a 30-inch diameter insulated trunk line and 0°C ambient temperature, 5% steam condensation will occur at a distance of about 14 km
  - Assume 10% water loss down hole
  - Assume 10°C minimum approach in CPF heat exchangers
  - No Air/Flue gas economizer
  - No make-up treating (Use direct steam injection to heat make-up water)

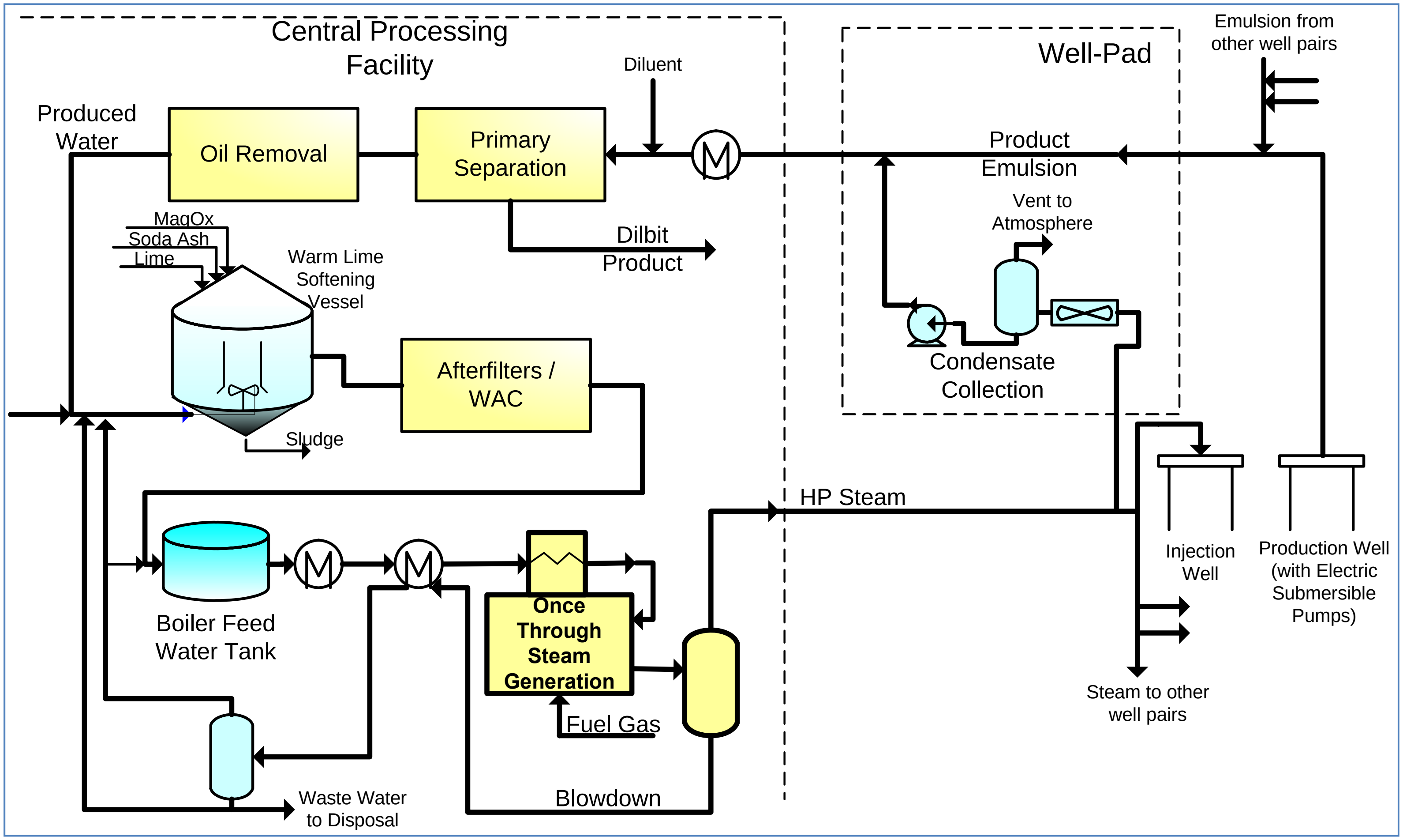
Figure 3.1 shows the base case CPF and well-pad configuration for the SAGD facility. Key features of this flow scheme are:

- Warm lime softening of produced water
- Once-Through Steam Generation (OTSG) to 80% quality steam

[4] Subcool reflects the temperature of the emulsion at the well-pad. In effect, steam will condense at reservoir pressure. The sub-cool is with reference to that condensing temperature. It is the difference between that condensing temperature and the temperature of the emulsion at the well pad. Thus if the steam condensing temperature is 230°C the emulsion temperature will be 210°C after sub-cooling. For purposes of this Study, other heat loss from gas mixing or well-bore loss are included in the subcool term.

- OTSG firing with fuel gas mix including imported natural gas and produced gas from wells/emulsion
- Condensation collection due to heat loss in the saturated HP Steam line
- Electric Submersible Pumps (ESPs) providing lift to the surface.
- No emulsion flashing at the well pad through to the Central Processing Facility (CPF). Flashing is eliminated by raising well pad discharge pressure. This step reduces heat loss from the well and maximizes process energy efficiency.

Figure 3.1
CPF and Well Pad Base Case Flow Scheme



We assumed the diluent properties shown in Table 3.1. This is based on pipeline condensate data from Enbridge.

Table 3.1
Diluent Properties

Density, kg/m3	**764.2**
TBP Distillation	
LV%	TBP, °C
0.1	62
10	87
20	98
30	110
40	117
50	126
60	137
70	146
90	190
99.9	292

Assumed raw bitumen properties are shown in Table 3.2. This is based on public domain data that is representative, on average, of Athabasca bitumen.

Table 3.2
Assumed Bitumen Properties

Density, kg/m3	**1,019**
TBP Distillation	
LV%	TBP
0.1	242.2
5	337.2
10	353.9
30	455.6
50	567.2

We summarize operating parameters for the SAGD base case in Table 3.3, and our high-level CAPEX estimate in Table 3.4. We report operating cost estimates in Table 3.5.

Table 3.3
SAGD Facilities – Base Case Summary

PTAC SAGD Base Case Summary All Values in Q1 2011 $	Basis Cost Info		Units		PTAC Base Case	
Case Description					**40 kbpcd**	
Purchased Feedstocks						
Diluent			t/d	BPSD	1,550	13,330
Synthetic Crude Oil			t/d	BPSD	0	0
Bitumen			t/d	BPSD	6,414	40,000
TOTAL IN			t/d	BPSD	7,963	53,330
Products Generated						
Dilbit (Bitumen + Diluent)				BPSD		53,303
Synbit (Bitumen + SCO)				BPSD		53,330
Bitumen (net diluent)				BPSD		40,000
Sulfur				MT/d		1.2
Power				MW		0
Purchased Utilities and Chems (OPEX)						
Natural Gas, HHV Basis	$/GJ	$4.38		MMBTU/h		1,918
Electricity	$/MWh	$77.18		MW		26.70
Water	$/m3 water	$0.00		m3/d CWE		3,034
Water Treating Chemicals	$/m3 water	$0.75		m3/d CWE		26,747
Oil Treating Chemicals	$/bbl oil	$0.44		bpsd		40,000
Emissions and Waste (OPEX)						
WLS Sludge	$/MT	$44.10	MT/d	MLB/h	39	85
Disposal Water	$/MT	$0.00	Mlb/d	m3/d CWE	0	1,978
Total CO2	$/MT	$15.00		MT/d		3,100
SOX	$/MT	$0.00		MT/d		0.0
NOX	$/MT	$0.00		MT/d		0.8
Unit Capacities						
Production & Water Treatment						
Well Pads - number				number		5
Vertical Drilled Wells at startup				number		29
Producers online (average for pump maintenance)				number		40
Oil treating				BPSD Emulsion	-	177,210
De-oiling				m3/d CWE		20,805
Warm Lime Softeners				m3/d CWE	-	26,747
Disposal Water Treatment				m3/d CWE		1,978
Evaporators				m3/d CWE		0
Steam Systems						
OTSG			Wet Steam	m3/d CWE		27,408
Drum Boiler				m3/d CWE		0
Steam Compressor				m3/d CWE		
Air Economizer				GJ/h		0
Other Units						
Sulfur Treating Block				MT/d		1.2

Note: The costs for the CPF Sulfur Treating Block reflect a LO-CAT or Sulferox® unit for gas treating (H_2S removal). Costs do not include allowances for amine units, sour water strippers or a Claus Sulfur plant.

Table 3.4
SAGD Base Case Capital Cost Summary

PTAC SAGD Summary All Values in Q1 2011 $	Units		PTAC Base Case	
Case Description			**Base Case 40 kbpcd**	
Drilling and Production				
Production				
Drilling & Completion (includes EPCM & Cont)	$/bbl	MM$		**192**
Production Pumps (TIC)	$/bbl	MM$		**50**
Total Drilling and Production - SAGD		**MM$**		**242**
Core Facility (ISBL)				
Well Pads				
Well Pads $	$/bbl	MM$	3,150	126
Gathering Lines/Pipelines $	$/bbl	MM$	1,575	84
Central Processing & Water Treatment				
Oil Treating $	$/bbl	MM$	1,625	65
De-oiling $	$/bbl	MM$	968	39
Warm Lime Softeners $	$/bbl	MM$	2,034	81
Evaporators $	$/bbl	MM$	0	0
Raw Water/DIsposal Treatment $	$/bbl	MM$	100	4
Steam Generation				
OTSG $	$/bbl	MM$	2,993	120
Drum Boiler $			0	0
Steam Compressor $	$/bbl	MM$	0	0
Other Units				
Sulphur Treating Block $	$/bbl	MM$	350	14
Total Construction Indirects and Other Costs $				224
Total ISBL - SAGD		**MM$**		757
Offsite Capex (Line items & Factored costs)				
Storage and Pipelines				
240 kV Power Line		MM$		
Utilities & Main Rack $				130
Product Storage $				22
CPF Infrastructure $				26
Connecting Pipelines		MM$		100
Road and Infrastructure Improvements		MM$		12
Non Process Buildings		MM$		9
Total OSBL - SAGD		**MM$**		**299**
Other Costs				
Home Office and Engineering Services				
EPCM Costs - Pads and Gathering Lines		MM$		15
EPCM Costs - CPF		MM$		102
Total EPCM Costs		**MM$**		**116**
Owner Cost, MM$				
Owner Costs (% of TIC)		MM$		78
Logistics (% of TIC)		MM$		26
Startup (% of TIC)		MM$		26
Capital Spares (% of TIC)		MM$		13
Catalyst and Chemicals (% of TIC)		MM$		13
Camp Operations $		MM$		50
Land (assumed = 0)		MM$		0
SAGD Total "Other Costs"		**MM$**		**206**
Totals				
Drilling and Production (Sub-Surface)		MM$		**242**
SAGD Surface Facilities		MM$		**1,378**
Contingency				
SAGD Contingency Percentage (excl sub-surface)		%		**25.0%**
SAGD Contingency (excl sub-suface)		MM$		**345**
Total Installed Cost (TIC) with Contingency				
Total Drilling and Completions				**242**
Total SAGD Surface Facilities				**1,723**
Total Installed Cost (TIC) with Contingency				**1,965**

Table 3.5
SAGD Base Case Operating Cost Summary

		PTAC Base Case
		Base Case 40 kbpcd
OPEX		
Variable Costs (per location)		
Power @ $77.2 / MW-hr	$ Mil/Yr	$16.7
Natural Gas@ $ 4.38 / GJ	$ Mil/Yr	$71.5
Water	$ Mil/Yr	$0.0
Water Treatment Chemicals	$ Mil/Yr	$6.8
Oil Treatment Chemicals	$ Mil/Yr	$6.0
Carbon Emission Costs @ $15 / MT	$ Mil/Yr	$12.8
Land Fill Costs @ $44.1 / MT	$ Mil/Yr	$1.3
SAGD Total "Variable Costs"		**$115.1**
Fixed Costs (per location)		
Maintenance of Production Pumps	$ Mil/Yr	$12.8
Maintenance Supply	$ Mil/Yr	$58.3
Insurance and Regulatory Fees	$ Mil/Yr	$4.9
Staffing	$ Mil/Yr	$19.4
SAGD Total "Fixed Costs"	$ Mil/Yr	**$95.5**
Total Operating Costs	$ Mil/Yr	**$210.6**

Key Assumptions for SAGD Capital and Operating Costs

- Capital costs are based on curve cost data from recent projects
- $15/MT CO_2 Penalty applied to direct emissions only (i.e., emissions in the battery limits)
- Production pumps (Electric Submersible Pumps) are based on a $370,000 cost per failure with an assumed 18-month Mean Time Between Failure (MTBF)
- Water disposal facility costs and pipelines (both make-up and disposal) are included in the capital costs. Chemical treating for water disposal is included in the water treatment chemical costs.
- Capital and operating costs shown are for production only. Costs for transport (pipeline fees) and upgrading are not included in Table 3.5.

- Bitumen and Crown Royalty costs are not included

3.3 Bitumen Upgrader Facility – Base Case Description

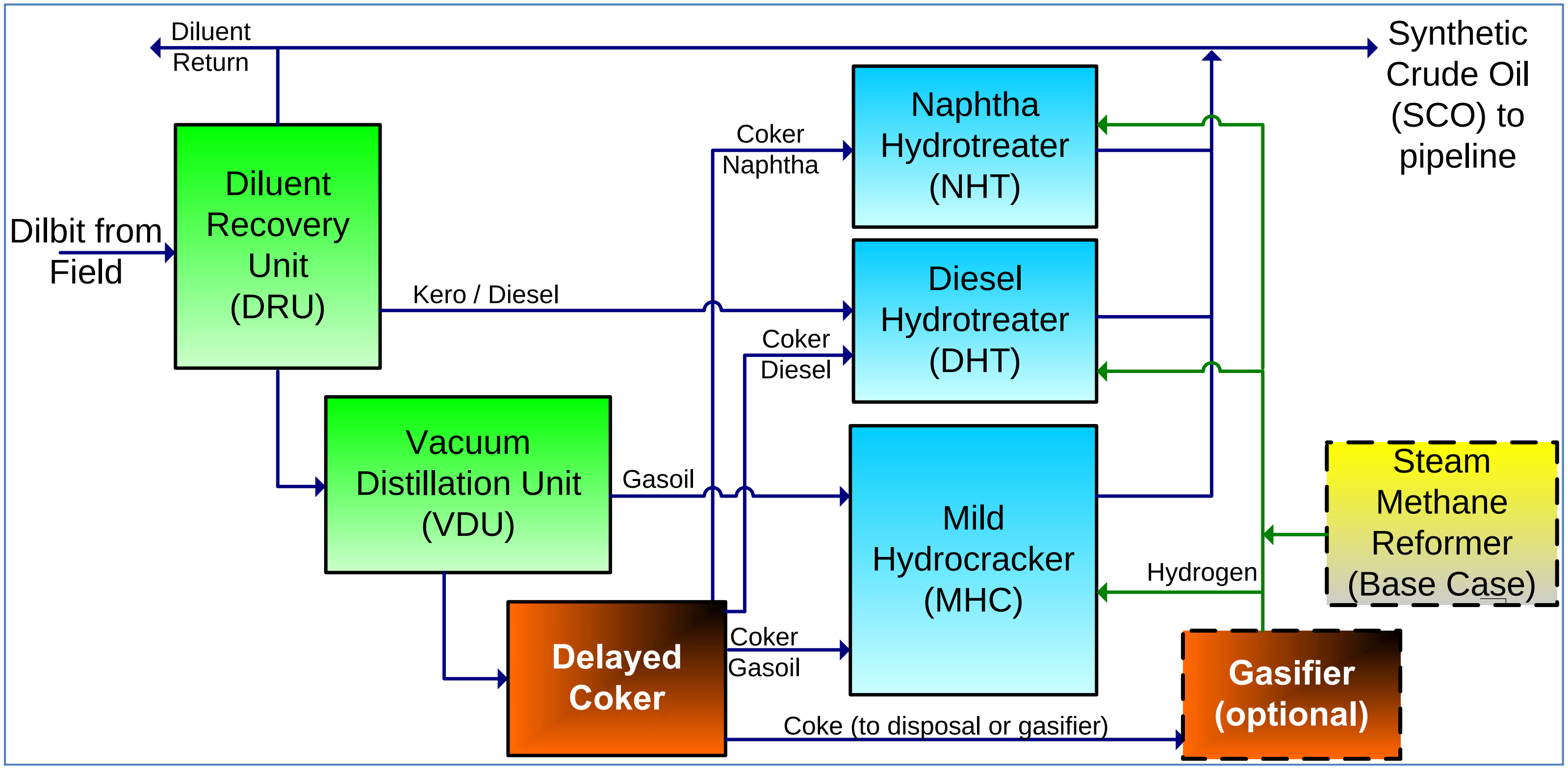
We assumed the following facility configuration for the bitumen upgrader:

- Capacity of 200,000 BPSD bitumen feed
- Diluent recovery unit (DRU) / vacuum distillation unit (VDU
- Delayed coker
- Naphtha and diesel hydrotreaters
- Mild-severity hydrocracker
- Steam-methane reforming (SMR) hydrogen plant
- Product synthetic crude oil (SCO) with the following properties:
    - 31° API
    - 40 Diesel cetane
    - 38% Gas oil

Figure 3.2 shows the base case CPF and well-pad configuration for the SAGD facility. Most of the electricity-use applications will change only the power and natural gas utility consumption of the blocks considered, although in some cases we will consider alternative technologies in place of the blocks shown below.

Since some of the technologies considered address gasification and hydrogen production, we developed an alternate base case with gasification (versus Steam methane reformer) for comparison. The product of gasification, synthesis gas (syngas), can be processed further to produce hydrogen and generate power (integrated gasification-combined cycle or IGCC). The syngas also can be used directly as a fuel source to displacing purchased natural gas.

Figure 3.2
Bitumen Upgrader Base Case Configuration



We show a short summary of the plant utility requirements in Table 3.6. Benefits of alternative technologies for upgrading will be found in:

- Reducing net energy requirements or carbon emissions,
- Economically shifting natural gas imports to power imports, or
- Reducing the overall costs of facilities.

Table 3.6
Bitumen Upgrader Utility Summary

		Base Case (SCO Production)	
	Price	**No Gasifier**	**With Gasifier**
Natural Gas	**$4.38 / GJ**	**5,344 GJ/Hr**	**0 GJ/hr**
Power	**$ 77.2 / MW-hr**	**99.5 MW**	**0 MW**
Water	**$ 0**	**16,500 m^3/d**	**29,200 m^3/d**
CO2 Emissions	**$15 / MT**	**11,032 MT/d**	**18,666 MT/d**

We summarize the operating parameters for the upgrader base cases in Table 3.7, the high-level capital cost estimates in Table 3.8, and the operating costs in Table 3.9.

Table 3.7
Upgrader – Base Case Summary

Case Description	Units	Base Case	
		No Gasifier	Gasifier
Purchased			
Athabasca bitumen	BPD	200,000	200,000
Diluent	BPD	66,000	66,000
Isobutane	BPD	0	0
Hydrogen	MMSCFD	0	0
Natural Gas	GJ/Hr	5,511	0
Power	MW	100	0
Water	M3/D	16,331	29,224
Products Generated			
Diluent	BPD	66,000	66,000
30-32 API SCO	BPD	176,669	176,669
Sulfur	LT/D	1,122	1,552
Coke	ST/D	6,249	0
Direct CO2 Emissions	MT/D	11,178	18,666
Indirect CO2 Emissions	MT/D	2,102	
SynGas	GJ/D	0	8,432
C3=	MT/D	103	103
Hydrogen	MMSCFD	0	0
Unit Capacities			
DRU	BPD	266,000	266,000
VDU	BPD	168,585	168,585
Coker	BPD	101,972	101,972
Canmet	BPD	0	0
NHT	BPD	12,820	12,820
Operating pressure	Bar(g)	<35	<35
DHT	BPD	56,427	56,427
Operating pressure	Bar(g)	125	125
MHC	BPD	99,511	99,511
Operating pressure	Bar(g)	140	140
Gasifier (IGGC + H2)	ST/D	0	6,249
Hydrogen Plant	MMSCFD	213	0
Amine Treating	LT/D	1,192	1,649
SRU	LT/D	1,122	1,552
Gasifier -electricity only	MW		954
Gasifier -H2 produced	MMSCFD		212

Table 3.8
Upgrader Capital Cost Summary

Case Description	Units	Upgrader Base Case	
		No Gasifier	Gasifier
Purchased			
Athabasca bitumen	BPD	200,000	200,000
Diluent	BPD	66,000	66,000
Natural Gas	GJ/hr	5,511	0
Pow er	MWhr	100	0
Products Generated			
Diluent	BPD	66,000	66,000
30-32 API SCO	BPD	176,669	176,669
Sulfur	LT/D	1,122	1,552
Coke	ST/D	6,249	0
CAPEX			
Diluent Recovery Unit	$Can Mil	$310	$310
Vacuum Distillation Unit	$Can Mil	$220	$220
Coker	$Can Mil	$920	$920
Naphtha Hydrotreater	$Can Mil	$50	$50
Diesel Hydrotreater	$Can Mil	$130	$130
Mild Hydrocracker	$Can Mil	$970	$970
Hydrogen Plant	$Can Mil	$320	
Sulfur Plant	$Can Mil	$170	$200
Air Separation Unit	$Can Mil		$2,050
Total ISBL	$Can Mil	**$3,090**	**$4,850**
Offsites	$Can Mil	$1,870	$2,090
Contigency	$Can Mil	$500	$700
Total Installed Costs	$Can Mil	**$5,460**	**$7,640**

Table 3.9
Upgrader Operating Costs

Case Description		Units	Upgrader Base Case	
Are Operating Costs are 2012 basis			No Gasifier	Gasifier
Basis Data				
Athabasca bitumen		BPD	200,000	200,000
Diluent		BPD	66,000	66,000
Natural Gas		GJ/hr	5,511	0
Natural Gas Imports		MW	1,531	
Pow er Imports		MW	100	
Total Energy Imports		MW	**1,630**	
Variable Expenses	**Price**			
Natural Gas	$4.38 /GJ	Mil $/YR	$213	$0
Pow er	$77.2 /MW-hr	Mil $/YR	$65	$0
Cat & Chem Cost	1.5% ISBL	Mil $/YR	$46	$73
Water Costs	$0 /MT	Mil $/YR	$0	$0
CO2 Penalty	$15 /MT	Mil $/YR	$59	$98
Total Variable Expenses		Mil $/YR	$382	$171
Fixed Expenses	**4.5% of TIC**	Mil $/YR	$246	$344
Total Expenses		**Mil $/YR**	**$628**	**$514**

Key Assumptions for Upgrading Capital and Operating Costs

- Natural gas imports for hydrogen and firing
- Power imports for process and utility unit requirements
- Alternative gasification case will be based on gasification of coke to meet hydrogen and power requirements
- Construction schedule and utilization will be independent from SAGD facility
    - Costs based on construction in Edmonton
- Bitumen and Crown Royalty costs not included

4.0 Technology Descriptions for SAGD Technologies Using Electricity

Eight electricity-based technologies and applications were selected and evaluated for SAGD processing:

1. Central Processing Facility (CPF) Electric Boilers
2. CPF Steam Compressors
3. Electric Boilers at the Well Pad
4. Well-Pad Steam Compressors
5. Steam Super-Heaters
6. Reverse Osmosis (RO) Make-Up Water Treatment
7. Mechanical Vapor Compression (MVC) Evaporators
8. Zero Liquid Discharge (ZLD) Facilities

A summary of the key technology providers, the largest unit sizes available, scale-up requirements and Jacobs Consultancy's opinions regarding the likelihood of scale-up, for the key technologies associated with each case, is provided in Appendix 8.

4.1 Electric Boilers in Central Processing Facility (Case SAGD-1)

Steam generation is the primary consumer of energy in a SAGD operation, a primary GHG producer, and the largest single operating expense, so efforts to improve energy efficiency with electricity should start here.

Electric Boilers offer the following potential benefits over OTSGs:

- Efficiency is higher (approaching 100% versus 80-85%)
- Electric boilers require less plot space and are easily modularized
- Information from vendors suggests that electric boilers may be less expensive than OTSGs, and are within the range of costs for circulating drum boilers
- Electric boilers operate effectively to 95% turndown, improving operating flexibility
- Direct carbon emissions (i.e., emissions from combustion) are essentially zero for electric boilers (indirect emissions will be higher).

Figure 4.1 shows the process configuration we considered in this Study (Case SAGD-1). Among the issues created by use of electric boilers are:

- Electric boiler applications are typically small scale, meaning there is limited information for boilers equivalent in size to a typical SAGD facility boiler. We estimate that it will take 20 boilers (at 4 MW each) to replace a single OTSG. There is no industry experience with once-through steam generation in electric boilers and, given the pressure of steam being generated, WLS is not sufficient for water treating for electric-type OTSGs. (Boiler Feed Water produced from a softening unit will have significantly higher levels of TDS than have been used for electric boilers in the past.) Thus a multistage vapor compression (MVC) evaporator would be specified for electric boilers. (We discuss the technology later in this section.) Evaporators will achieve water qualities approaching ASME (American Society of Mechanical Engineers) Standards which is consistent with most electric boiler vendor requirements.[5]

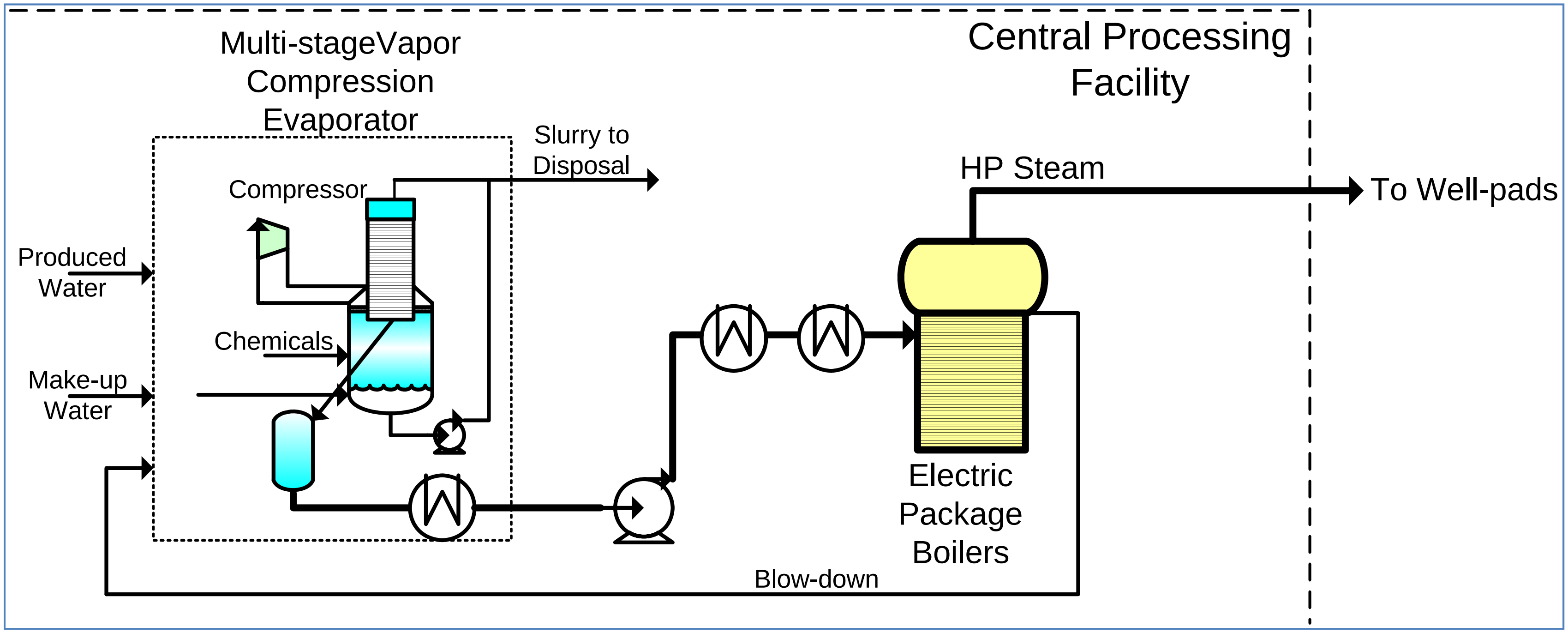
In addition to the boilers and the evaporator the following configuration changes are anticipated:

- The blowdown[6] rate would decrease from 20% of charge to 5% or less. As water quality is improved it is possible to blow down much less water and remain within boiler tube guidelines for solids content. Thus blowdown handling would be modified. This change should reduce costs, but less low-pressure steam would be available for utility services including make-up water preheat (e.g., pick heater).
- Glycol air preheat, flue gas preheat and other auxiliary exchangers associated with the OTSG would not be required.
- Boiler feed water preheat exchangers still would be required to reduce boiler heat requirements through recovery of heat from emulsion and produced water. Eliminating these exchangers would increase both the boiler heat requirements and the size of the glycol system to cool incoming emulsion.

[5] There are no electric boilers that are specified to be able to use non-treated water. ASME boiler water quality (i.e. water in the drum) for a 1000 psig boiler is <1000 ppm TDS. Assuming a 5% blowdown that means the boiler feed water quality must be 50 ppm TDS.

[6] Blowdown is the portion of boiler water that is purged to remove solids to prevent scaling in boiler tubes.

Figure 4.1
Electric Boiler in CPF (Case SAGD 1)



4.2 Steam Compressors in Central Processing Facility (Case SAGD-1A)

An alternative to electric boilers would be to use steam compressors to compress low-pressure "waste heat" steam to steam at pressures suitable for SAGD injection.

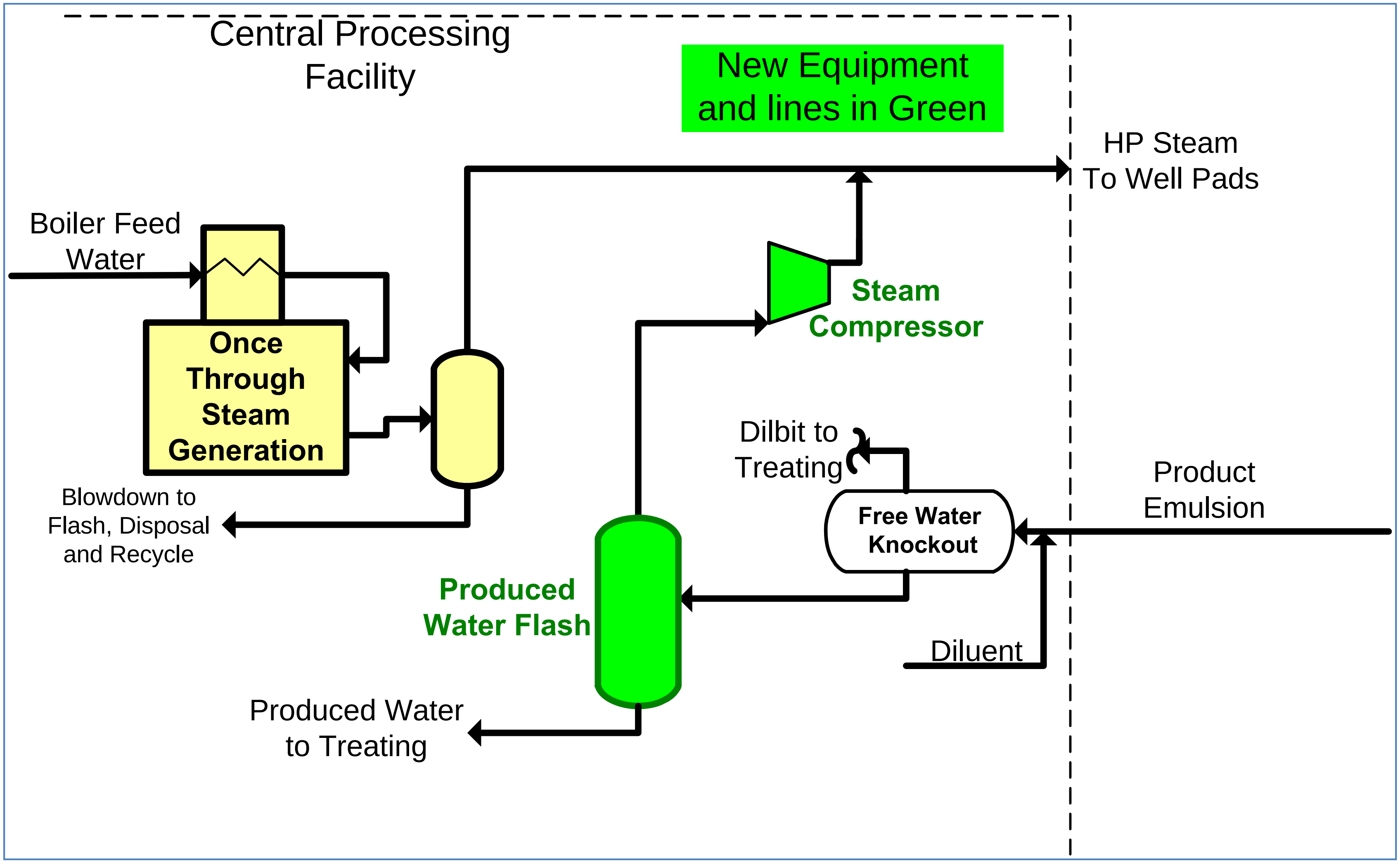
Compression of waste heat steam can be more efficient than boiling an equivalent amount of condensate because the heat of vaporization, which is a large portion of boiler energy requirements, is eliminated.

There are a number of ways to use steam compression with the CPF, including flashing OTSG blowdown or importing vapor from another location, but the proposed configuration for this Study is shown in Figure 4.2. We evaluated a scheme where we would flash produced water after the primary separation and route the vapor to a compressor. The remaining water would be treated and boiled using the standard OTSG configuration.

Potential advantages for steam compression include:

- Effective use of low pressure waste heat
- Potential that flashing produced water could reduce water treating, since water treating costs are largely based on volume, not concentration
- Use of compression to supplement OTSG steam may increase overall plant availability by allowing steam generation to continue during an OSTG or WLS failure

Figure 4.2
Steam Compressor in CPF (Case SAGD 1A)



However, implementation in a SAGD process might not be feasible. The US Department of Energy issued a document (*DOE/GO-102012-3415 – Jan 2012*) encouraging the use of steam compressors to improve energy utilization. Their findings suggest that steam compressors are economic in situations where the required compression ratio is less than two, and where the recompression is justified by the process pinch curve. For SAGD neither of these criteria can be met, since:

- Based on the level of heat from the well pad (210°C or less), flashed steam would be less than 1000 kPag, meaning a compression ratio of 7 or greater would be required.
- For a process to be suitable for steam compression applications, the pinch curve must show excess heat available at levels above 150°C. For SAGD facilities we have reviewed there is no excess heat available above 100°C. Generating LP steam for compression would directly increase the steam boilers' energy input, meaning there would be no efficiency gain.

The equipment required for steam compression would be the compressor and associated equipment along with a produced water flash. This cost would be offset by a reduction in the number of OTSGs and reduced water treating capacity.

4.3 Electric Boilers at the Well Pad (Case SAGD-2)

A common source of heat loss in SAGD facilities is convective line losses in the high-pressure steam lines. Typically, the resulting condensate is collected at the well pads and re-injected into the emulsion line. Overall, this results in two inefficiencies—a downgrade of high-level heat and a downgrade of high-quality water—since the condensate water then must be reprocessed through the water treater and reheated in the boiler.

An alternative to this operation is to use a boiler at the well pad to re-vaporize the condensate and reinject it into the well, as shown in Figure 4.3 (Case SAGD-2).

Potential benefits of electric boilers at the well pad include:

- Increased energy efficiency and reduced emissions
- Reduced water treating capital and operating costs
- Reduced sizing of steam and emulsion pipelines
- The duty required for well pad boilers is well suited to the typical size of electric boilers

- Electric heaters would require less plot space and auxiliary equipment than an equivalent fired boiler which might be critical for well-pad construction.

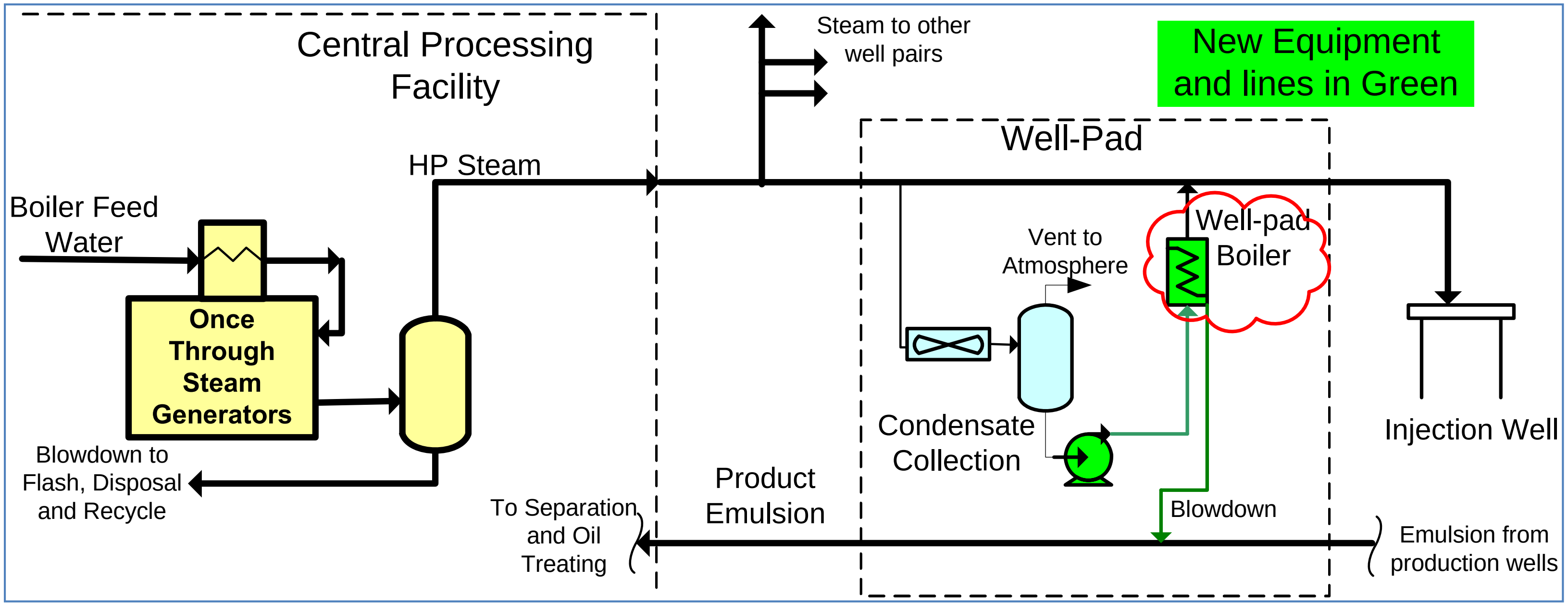
Challenges to implementing the well pad boilers include the following:

- Boilers would be located in remote locations with limited opportunities for operator intervention. Variations in external temperatures and steam flow rates could mean large changes in boiler load requiring automated control functions with remote monitoring.
- The amount of condensation that occurs is a function of line length. If pipe runs from the CPF were minimized (by constructing smaller CPFs, for example), the benefits of well pad boilers might not justify the cost.

The additional equipment and processing changes required by well pad boilers include:

- High-pressure boilers
- High-pressure condensate pump
- Auxiliary equipment for electric supply, water treatment and blowdown handling

Figure 4.3
Electric Boilers at the Well pad (Case SAGD 2)



4.4 Compressors at the Well Pad (Case SAGD-3)

An alternative to well pad boilers would be to use a compressor to inject flashed steam from condensate back into the steam header and injection wells, as shown in Figure 4.4 (Case SAGD-3).

The potential advantage to well pad compressors would be:

- A compressor, compared to a boiler system, would help mitigate reliability issues resulting from poor water quality[7]

Technical issues associated with a well pad compressor include:

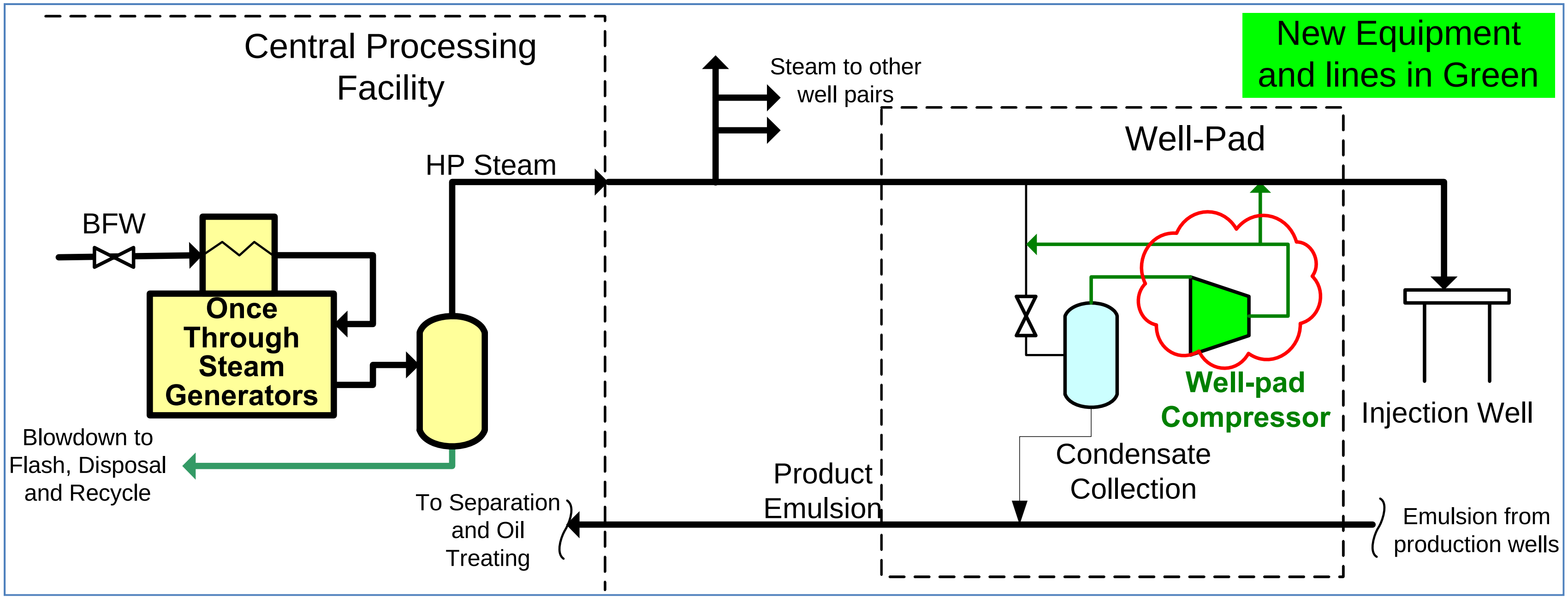
- Compressors offer less turndown flexibility than boilers and are more prone to upsets than boilers.
- The condensate system must be held at a high pressure to minimize the compression ratio of flashed steam.
- The potential for efficiency improvements might be small since high condensate subcooling or low compressor efficiency (e.g., high vapor recycles, valve losses) could reduce or eliminate operating cost savings.

The process configuration changes would be relatively minor and include:

- A compressor (centrifugal or reciprocating)
- Auxiliary equipment including motor, knock-out drum and lube system

[7] In particular, we might need to add oxygen scavengers and other chemicals to meet water quality requirements for the boiler. With a compressor this will not be an issue, but adequate liquid knock-out must be available.

Figure 4.4
Well Pad Compressor Configuration (Case SAGD-3)



4.5 Electric Steam Superheating (Case SAGD-4)

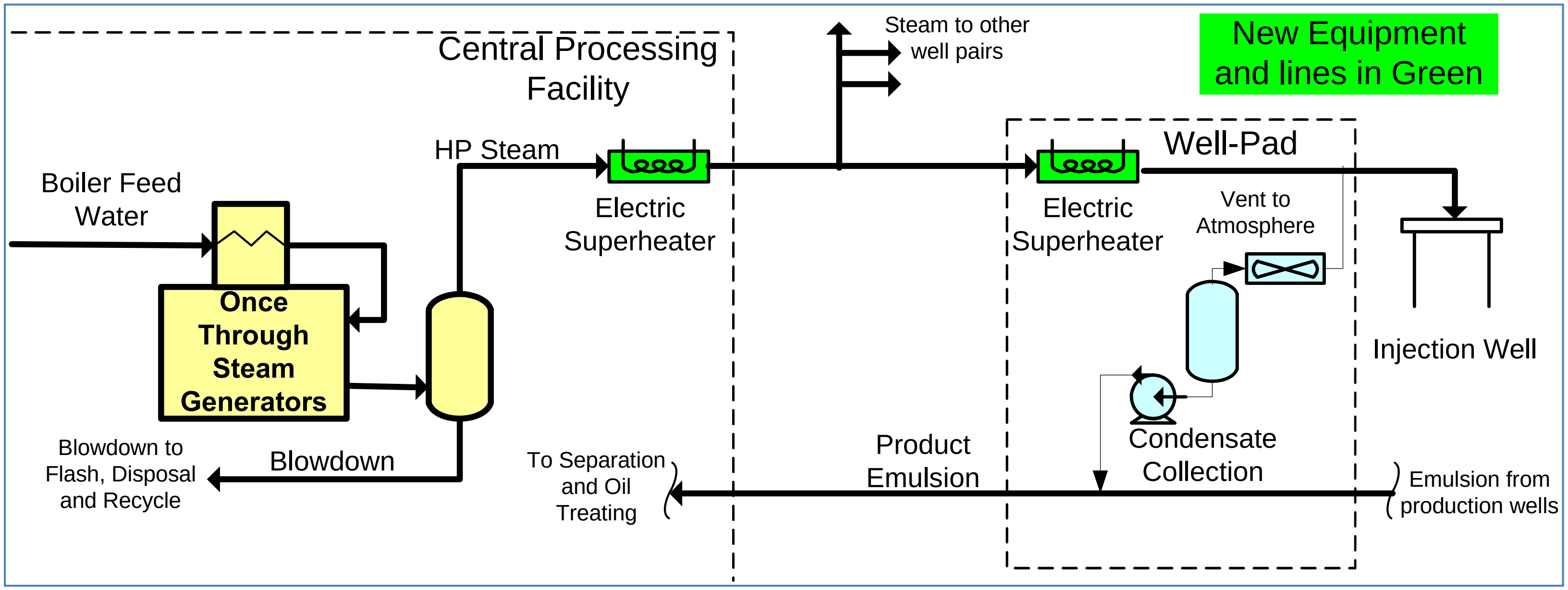
Electric heaters are used for steam superheating in petrochemical and power generation facilities. Steam in SAGD facilities is generated at saturated conditions, meaning that line heat loss will result in steam condensing. Superheating the steam above its saturation temperature can prevent condensation from occurring. Electric heaters offer the following potential advantages for SAGD facilities:

- Superheating saturated steam from Once-Through Steam Generators would eliminate line condensation, improving steam utilization and energy efficiency.
- As for well pad boilers, eliminating condensation would reduce water recycle and improve energy efficiency.
- Electric heaters could be installed as in-line heaters in the steam header such that there would be no impact on plot space or process piping.
- Superheaters and/or tracing could be applied along the length of the steam trunk line, allowing tight control of header temperature and reducing heat loss.

One of the main challenges to using electric superheaters is the potential for corrosion. Unlike traditional steam systems using high-quality boiler feed water, SAGD steam may contain significant levels of hydrogen sulfide and other contaminants. Saturated steam also may have condensate droplets which will concentrate impurities such as hydrochloric acid and ammonium sulfide. Superheaters must have appropriate higher metallurgy to deal with these contaminants. We adjusted our cost estimates in this analysis to reflect more robust equipment specifications.

As we show in Figure 4.5, the additional equipment required for steam superheating would be minimal. Heaters would be installed in-line and would require only electric power supply. It might be possible to eliminate condensate collection facilities, though some condensate removal might be required to prevent line hammering during start-up and to allow draining during shutdown. This cost of condensate collection facilities should be small relative to total well pad costs.

Figure 4.5
Electric Steam Superheater Configuration (Case SAGD-4)



4.6 SAGD Make-Up Water Treatment (SAGD Case-5)

Treating of SAGD produced water to convert it to suitable boiler feed water is a critical processing step in a SAGD facility. The produced water, primarily condensed steam separated from bitumen, is high in salt, silica and organic impurities, which makes purification very difficult. While various water-treating alternatives have been considered for SAGD, the only technologies proven in commercial applications so far are softening and evaporation.

Electrodialysis (ED) and reverse osmosis (RO) have been tested for produced water, but hydrocarbons, both dissolved and colloidal, have limited the effectiveness and reliability of these technologies in reducing salt levels.

However, these technologies have been used to treat brackish make-up water as shown in Figure 4.6. Pretreating make-up water should provide the following potential benefits:

- Treating make-up water would allow the stream to be preheated using waste heat from the glycol system or from flue gas, improving energy utilization. In cases where brackish water is not pretreated, salt precipitation would occur in preheat exchangers. For this reason, a pick heater (direct steam injection) is used for preheating in the absence of make-up water treating.
- Treated make-up water could bypass the produced water warm lime softener, reducing the size of the WLS.
- Electro-dialysis and reverse osmosis would eliminate the need for treating chemicals, reducing sludge production and simplifying plant operator tasks. The primary operating cost for both technologies is electric power consumption.

The challenges facing make-up water treating technologies include:

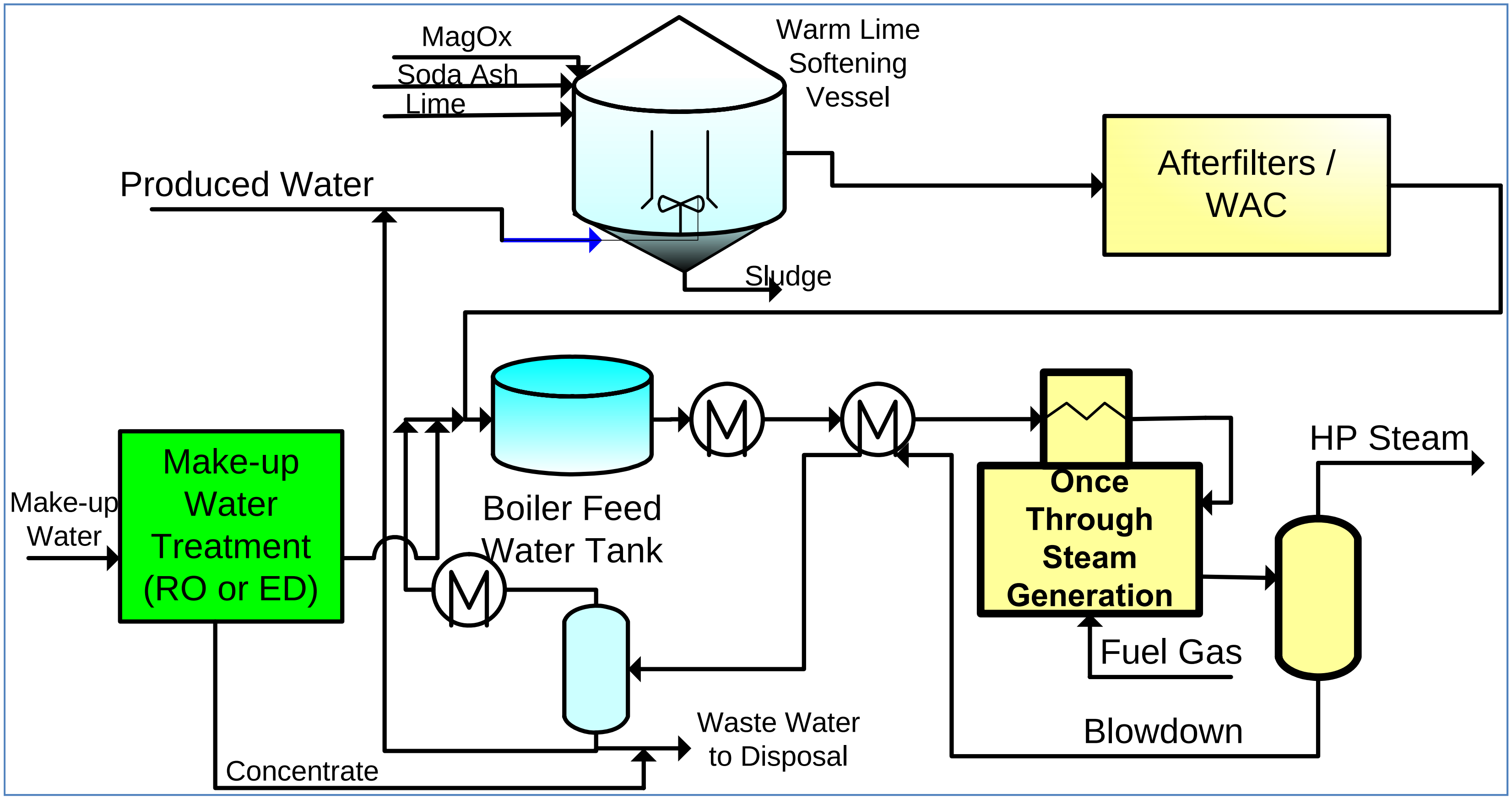
- The cost of treating make-up water and produced water separately is usually higher than a single treating facility.
- The technologies must be able to work at low temperatures (40°C or lower) to allow for heat integration at the CPF.
- Rejection rates from RO treatment can be high, especially with high TDS make-up water. This may increase net water consumption over co-treatment of produced and make-up water.

Electro-dialysis is a well established treating technology, and should be adequate for water quality up to 15,000 ppm. However, for services over 5000 ppm, reverse osmosis is favored.

While these treatment technologies do not generate a solids waste stream, they do generate a liquid concentrate (approximately 50,000 ppm solids) that must be disposed of as a waste water stream.

The additional facilities required for water pretreatment would be the make-up treatment facilities. This equipment would replace the pick heater, and we estimate that the incremental cost of the pretreatment facility would be offset by reducing the size of the warm lime softener.

Figure 4.6
Water Pre-Treatment (SAGD Case 5)



4.7 SAGD Water Treatment – MVC Evaporators (SAGD Case-6)

Mechanical Vapor Compression (MVC) evaporators have been established as an effective means of treating produced water from SAGD production wells. However, evaporators are less common because they consume large amounts of electrical power, which increases operating costs relative to warm lime softening. In addition, the high-quality boiler feed water produced by evaporators is not required for OTSGs.

Potential advantages to using evaporators include:

- High-efficiency circulation boilers can be considered, potentially improving boiler energy utilization by reducing blowdown.
- No solid wastes are generated as in the case of WLS, eliminating the cost and risk associated with landfilling sludge. However, disposal wells for disposal of liquid concentrate from the evaporators are required.
- Evaporators leave organics in the concentrate phase for disposal, eliminating the potential for buildup and fouling in the steam generating equipment.
- Evaporators are more flexible in dealing with a range of make-up water qualities.
- Evaporators substantially reduce the amount of water sent to disposal by maximizing the solids concentration of the discharge.
- MVC evaporators require much less plot space than alternative evaporator technologies such as Multiple Stage Flash (MSF) or Multiple Effect Distillation (MED). This substantially reduces the cost of this technology relative to competing technologies.
- Reduced water disposal rates.

A typical evaporator/circulating boiler configuration is shown in Figure 4.7. The challenges in installing an MVC evaporator include:

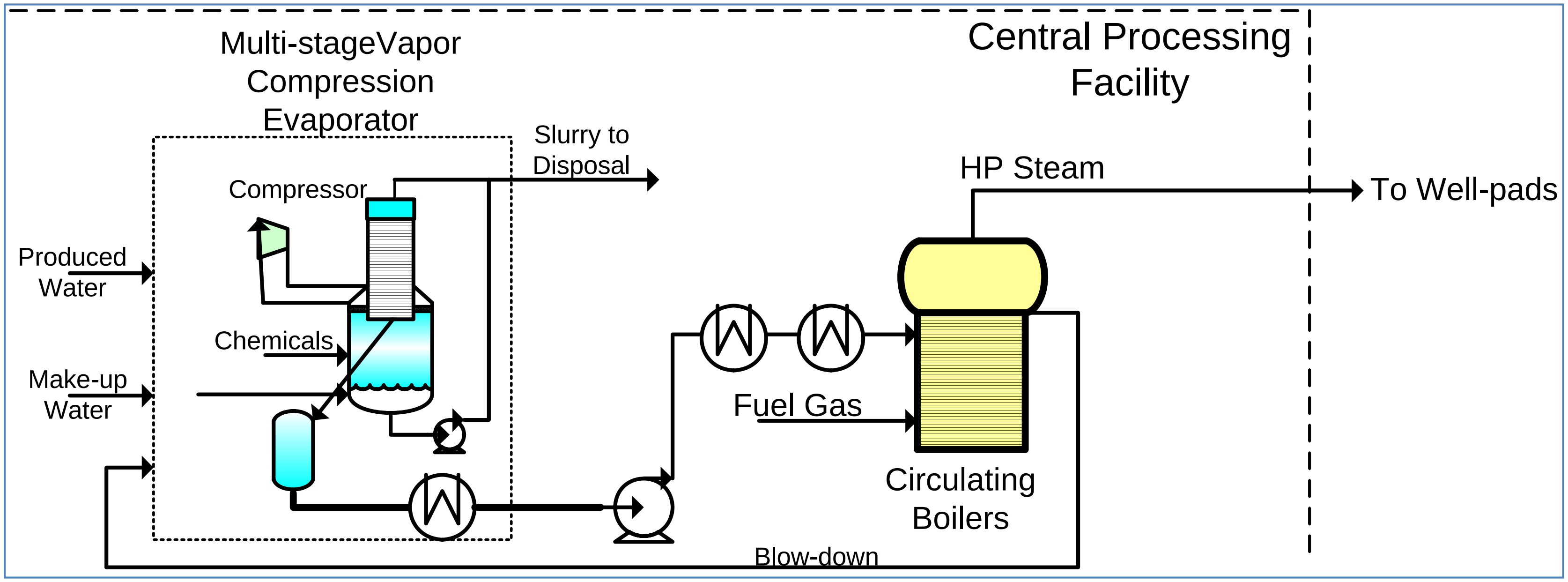
- Concentrate disposal typically requires dedicated disposal wells along with treatment steps to prevent fouling of the injection wells.
- Compared to a highly-integrated SAGD facility, forced circulation boilers do not substantially improve energy efficiency over OTSGs; therefore, the MVC evaporators/circulating boilers may be less energy efficient because of the added power consumption.
- Pilot experience suggests that evaporators cannot achieve ASME quality requirements (relative to pressure levels) for circulating boiler water without higher-than-normal

blowdown levels. However, we note that most manufacturers have modified their boiler design for SAGD services to deal with this issue.

Additional or critical equipment requirements for MVC evaporators include:

- Replacing WLS with MVC Evaporators for produced water treating.
- OTSGs may be used, but circulating drum boilers may offer slightly better efficiency because the amount blowdown can be reduced. Also, circulating boilers usually cost less than OTSGs. With the additional circulating flow, a higher rate of heat transfer (heat flux) can be achieved, reducing area requirements and therefore the cost of the drum boilers. For purposes of economic comparison, we have assumed that OTSGs are replaced with circulating boilers, reducing boiler costs.

Figure 4.7
Produced Water Evaporator Configuration



4.8 SAGD Water Treatment - Zero Liquid Discharge (SAGD Case-7)

"Zero Liquid Discharge" (ZLD) is a term for facilities that have little or no water discharge. Water is concentrated by evaporators and remaining salts and impurities are concentrated by crystallizers, centrifuges, dryers and other technologies. The majority of the water is recovered and recycled to make-up water treating while the remaining solids are landfilled.

ZLD can be implemented with WLS and a blowdown evaporator, but is more commonly applied with produced water evaporators with additional recovery from the concentrate, as shown in Figure 4.8.

The potential advantages of Zero Liquid Discharge include:

- Make-up water requirements are minimized and there are no water disposal issues.
- The additional water recovery can be accomplished almost entirely using electric energy.
- ZLD provides the flexibility to deal with varying levels of dissolved solids in produced and make-up water and still being in compliance with ERCB water recycle targets.

Disadvantages of Zero Liquid Discharge include:

- Capital and operating costs for ZLD systems are higher than for waste water treatment and disposal systems.
- ZLD systems generate more GHG emissions (combining direct and indirect) than other water treating technologies.
- Reliability and operability can be lower because of the difficulty in concentrating and crystallizing hydrocarbon-laden brine. Subsequent drying of the crystallizer slurry is difficult.
- The organics in SAGD produced water create safety and reliability issues associated with crystallizers and dryers. While electric dryers have not been tried in this service, the risk of organics combustion in dryers likely would remain.
- Handling and landfilling these contaminated solids add additional safety and environmental considerations.

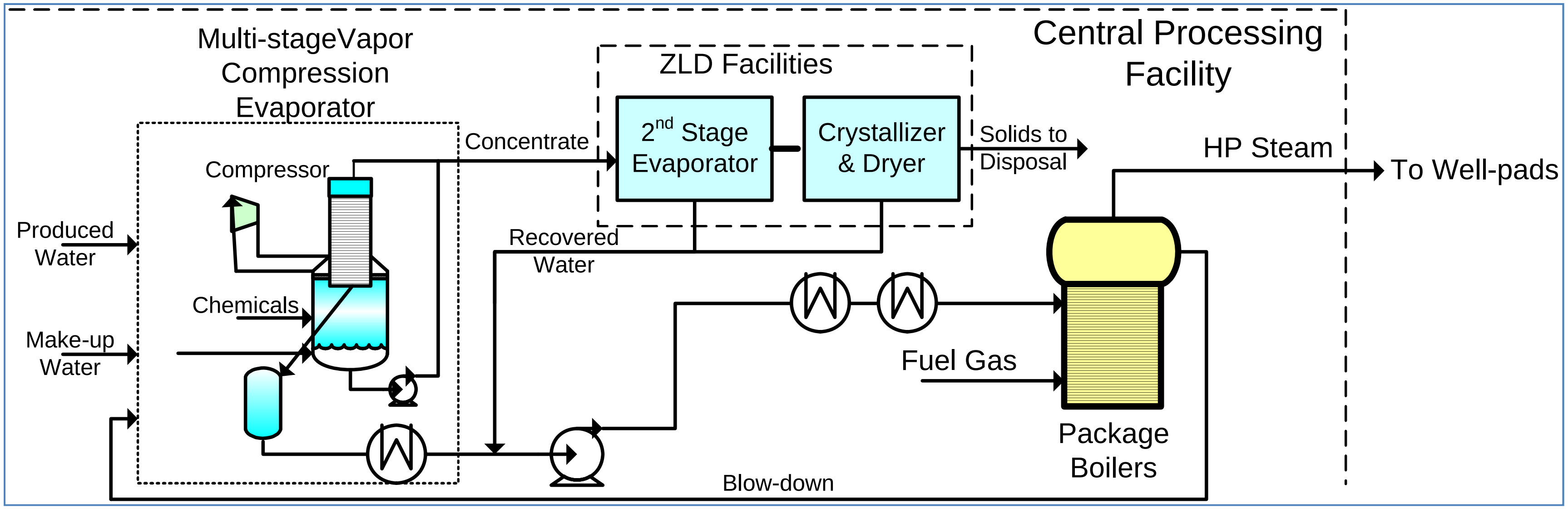
Additional equipment required for ZLD includes:

- A second-stage evaporator. The first-stage evaporator will concentrate solids to 50,000-90,000 ppm while the second stage will concentrate to 200,000 ppm or almost 20%

TDS. Depending on the TDS of the feed water and other constraints, a third stage may be required.

- Crystallizer and Dryer—These facilities will remove the remainder of the water and dry the remaining solids sufficiently for delivery to a landfill.
- Solids handling facilities such as truck loading.

Figure 4.8
ZLD Configuration for MVC Evaporator Treating



4.9 Other Technologies

Downhole Steam Generation

Technology exists[8] that uses electric heaters within a producing well to generate steam. The technology was developed as a method of preventing clay ingress into a well by maintaining positive steam pressure. This technology was not considered in the Study because:

- Information on the application and use of this technology is limited, and there is no evidence that the application is more than conceptual.
- For the examples of this application in the public domain, the levels of steam generation are much smaller than would be required for commercial SAGD operation. Other downhole electro-thermal technologies for bitumen production (ET-DSP, IESIEH) have more field-testing in Alberta and may offer greater benefits in reducing or eliminating steam generation. We discuss these technologies in a later section of this Report.

Produced Gas Compressor

Produced gas compressors could be used to re-inject produced gas downhole, reducing steam generation requirements. This technology was not considered because:

- We have found no record of pilot testing for this concept. Key questions include compression costs and issues with high-pressure sour gas.
- The scheme would increase well pad complexity and operating risk with limited benefits to CPF design.
- Other compressor systems such as condensate collection compressors or CPF steam system compressors would reduce risk by compressing water vapor and not hydrocarbons.
- The scheme is not consistent with mechanical lift operation in which no produced gas is generated. (Mechanical lift operation is the basis of our analysis.) Application of this technology would reduce energy efficiency by reducing the emulsion return temperature.

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[8] Meshekow "Horizontal Steam Generator for Oil Wells", US Patent 5,142,608, August 25, 1992

5.0 Technology Descriptions for Upgrading Technologies Using Electricity

The seven technologies that were selected and evaluated for bitumen upgrading are:

- Hydrogen production via electrolysis of water
- Electric heaters and reboilers[9]
- Hot oil heating systems
- Heat pumps
- Vacuum compressors
- Oxygen enrichment of fired heaters[10]
- Flexicoking™

5.1 Electrolytic Hydrogen Production (Case UG-1)

Hydrogen production via electrolysis of water is well-known, at least at smaller scales of production (250 - 3000 scf/hr). At least one type of system, the alkaline hydrolysis cell, has been in use for years.

If electricity were available at a reasonably low cost and if the technology capital costs were low enough, the production of the hydrogen required in significant quantities for bitumen upgrading from water, via electrolytic techniques, might make sense.

Hydrogen is produced via electrolysis by passing electricity through two electrodes that are placed in water. Electrolysis splits the water molecule and produces oxygen at the anode and hydrogen at the cathode.

Three types of industrial electrolysis units are available today:

- **Unipolar Alkaline Electrolyzer:** This type of electrolyzer uses an aqueous solution of potassium hydroxide (KOH), which has high conductivity. The unipolar electrolyzer resembles a tank and has electrodes connected in parallel. A membrane is placed

[9] The main applications will be within the diluent recovery unit (DRU-- steam flash drums) and the mild hydrocracker (stripper columns and reactor loop).
[10] For flue gas combustion heaters

between the cathode and anode, which separates the hydrogen and oxygen as the gases are produced, but allows ion transfer.

- **Bi-polar Alkaline Electrolyzer:** The bipolar design also uses potassium hydroxide and resembles a filter press. Electrolysis cells are connected in series, and hydrogen is produced on one side of the cell, while oxygen is produced on the other side. A membrane separates the electrodes.
- **Solid Polymer Electrolyte (SPE) Electrolyzer:** This system also is referred to as a PEM or Proton Exchange Membrane electrolyzer. In this unit the electrolyte is a solid ion conducting membrane as opposed to the aqueous solution in the alkaline electrolyzers described above. The membrane allows the hydrogen ion to transfer from the anode side of the membrane to the cathode side, where it forms molecular hydrogen. The SPE membrane also serves to separate the hydrogen and oxygen gases, as oxygen is produced at the anode on one side of the membrane and hydrogen is produced on the opposite side of the membrane.

Today, only bi-polar alkaline electrolysis units are conceivably large enough to theoretically replace the SMR for a commercial-scale upgrader. However, many units in parallel would be required with today's technology scale. Three of the leading firms that sell commercial bi-polar alkaline electrolysis units are Hydrogenics, NEL-Hydrogen and Teledyne.

For a commercial installation in conjunction with an upgrader, a water purification unit might be required (some technology suppliers incorporate water purification with their units and some do not), and a hydrogen compressor would be required. (A typical electrolysis unit outlet pressure is only about 150 psig or 1035 kpag, whereas upgraders require much higher hydrotreating pressures.)

5.2 Electric Reboilers (Case UG-2)

A great deal of the energy used in upgrading is expended on reboiling in hydrocarbon splitters, debutanizers and other fractionators to achieve desired product quality specifications. These reboilers are fuel-fired or steam heated and potentially could be replaced with electric heaters.

Figure 5.1 shows a column with a stab-in or immersion-type reboiler.

The potential advantages to using electric reboilers and heaters include:

- Electric Heaters typically occupy less plot space and are lower cost than equivalent fuel gas or steam heaters.

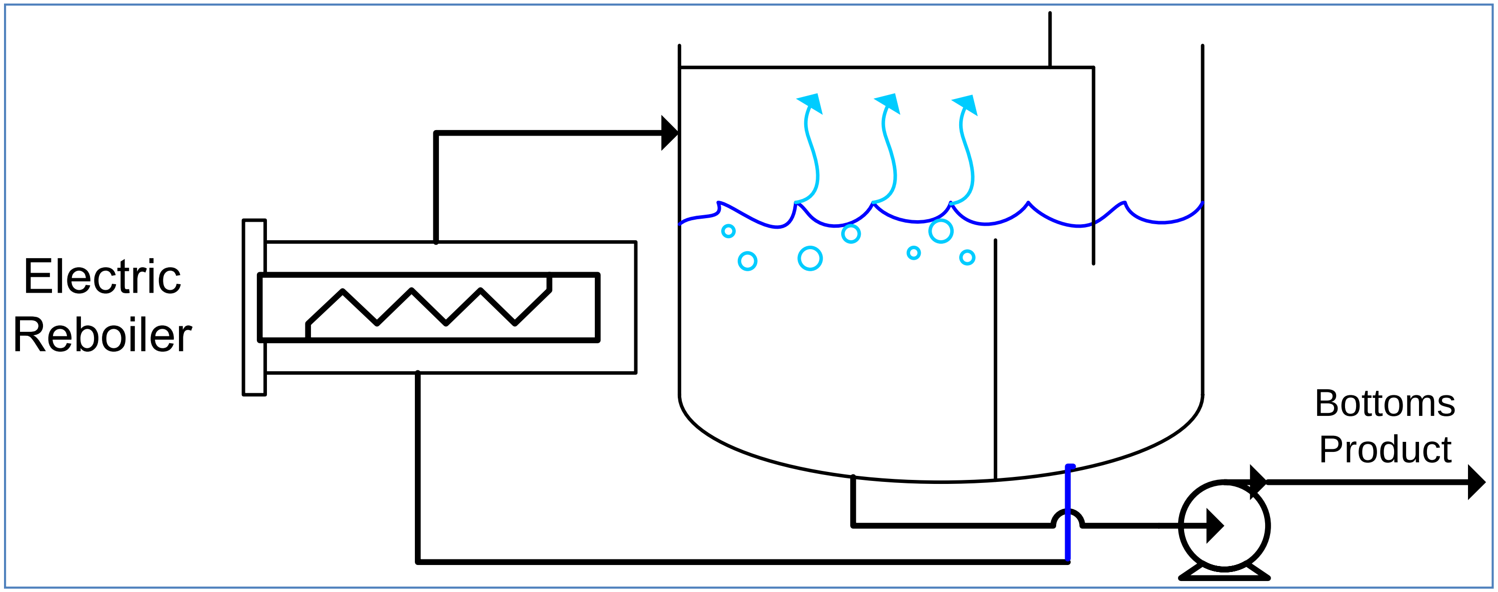
- Electric heaters eliminate piping and congestion around towers.
- Electric heaters offer much better turndown and potentially better control than equivalents.

The challenges facing this application include:

- In a non-integrated upgrader (i.e., separate from bitumen production facilities), most of the medium- and high-pressure steam used for reboiling is generated by process waste heat from units such as the SMR hydrogen plant and sulfur plants. Eliminating reboiler heat applications will eliminate uses for this steam except possibly for rotating equipment turbines (i.e., reducing electric power consumption for rotating equipment in favor of steam power). In this Study we assumed that SMR steam generation could be reduced by improving the SMR unit thermal efficiency (e.g., air preheat) to accommodate an overall reduction in steam demand.
- The areas where electric heaters can replace natural gas typically involve heavy oil heated at high temperatures such as a vacuum or coker furnace. While technically feasible there is limited experience with this operation and a potential risk of furnace tube coking if sufficient mass and heat flux are not maintained (maintaining the optimal heat transfer to avoid surface coking).

In this screening Study, we considered replacement of typical steam heaters in multiple applications. We evaluated capital costs and energy consumption for replacing the dilbit flash preheaters (steam heat) in the Diluent Recovery Unit with electric heaters. Based on cost and utility comparisons we analyzed the relative benefit of electric reboiling versus natural gas or steam heat.

Figure 5.1
Electric Reboiler for Upgrader Service (Case UG-2)



5.3 Electric Hot Oil Systems for Bitumen Upgrading (Case UG-3)

Hot oil is used in various industries such as petrochemicals, pharmaceuticals and food processing to transfer electrical energy to process units. Hot oil exchange is favored over direct electric heat because it is easier to control the heat transfer rate and avoid coking.

A hot oil utility could replace fuel gas heaters or be used to preheat heater feeds and reduce duty. As shown in Figure 5.2, hot oil could be circulated to all process units. Hot oil systems are limited to a supply temperature of about 450°C maximum to avoid breakdown of the hot oil heating medium.

Potential advantages to electric hot oil heating include:

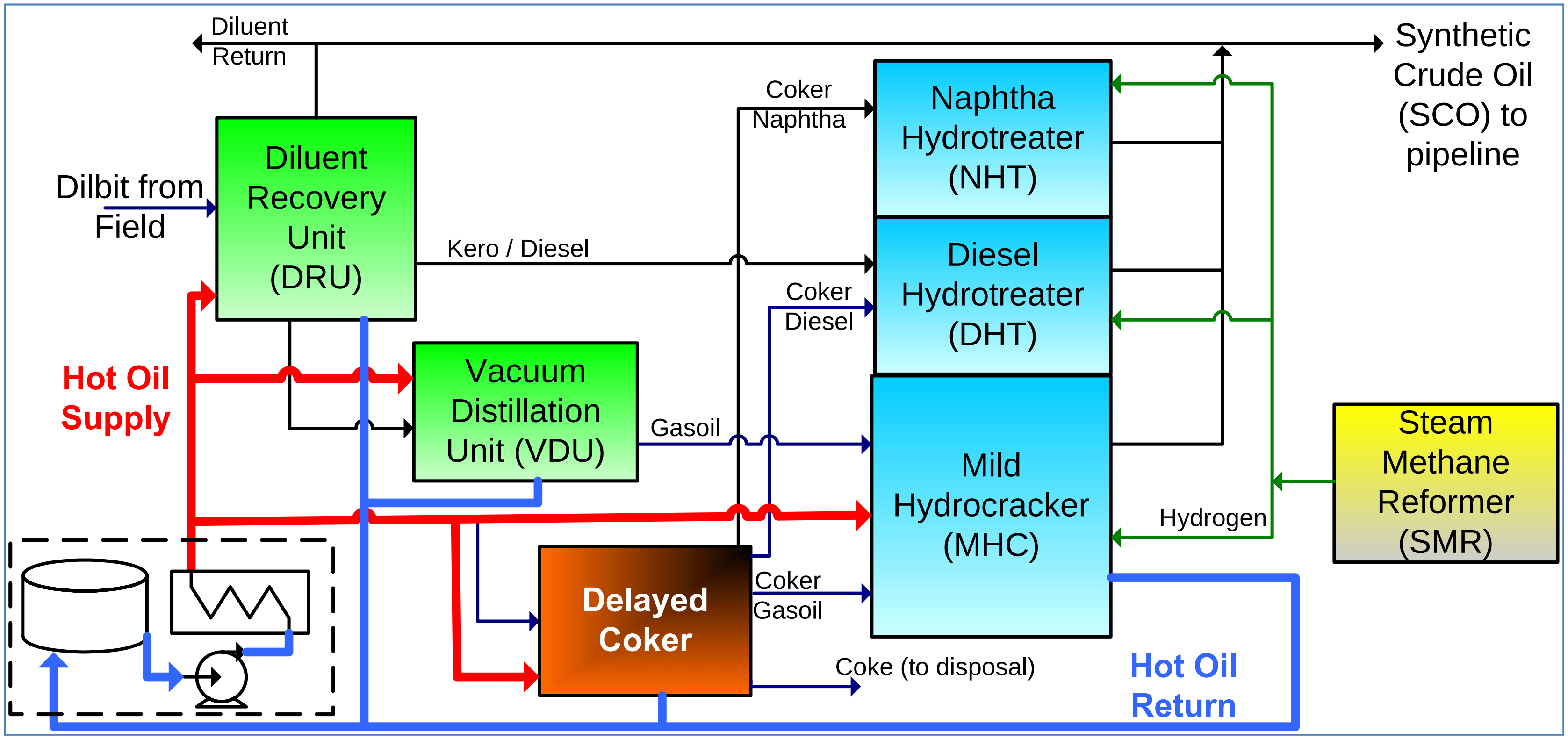
- Electric heating is more efficient than fired heating. Even given heat loss due to hot oil circulation, the hot oil system should require less net energy than the fired heat it would replace.
- The hot oil system would significantly reduce the direct emissions at the site, though total emissions will likely increase.
- Hot oil can be cascaded from high temperature to lower temperature units reducing circulation requirements.
- Shell and tube hot oil exchangers should require less plot space than an equivalent fired heater.

Design issues include:

- Some services such as the coker heater may require a process temperature too high to allow efficient use of hot oil. These systems could only utilize hot oil exchange upstream of the process heater to reduce direct firing.
- The supply system for hot oil would be much higher in cost than an equivalent fuel gas system. Operating costs (pumping, oil losses, and maintenance) also would be higher, reducing net savings.

Additional equipment requirements would be the utility heater, collection tank and hot oil pump. The cost of these items would be offset somewhat by the cost savings for shell and tube exchangers replacing fired heaters. There would be an added cost for the hot oil supply system. Natural gas and fuel gas systems would not be eliminated, but would be significantly smaller. We note that historically, electricity supply systems (grid delivery) are less reliable than natural gas supply pipelines.

Figure 5.2
Hot Oil System using Electric Heat (Case UG-3)



5.4 Heat Pumps for Bitumen Upgrading (Case UG-4)

Heat pumps use mechanical energy to move energy from a lower- to a higher-temperature medium. In a distillation application, a heat pump can be used to compress an overhead vapor steam such that its dew point temperature is above the distillation column bottom temperature. This allows the compressed overhead stream to condense and exchange heat with the bottom fluid in the column reboiler.

The heat pump proposed here works similarly, but instead drops the pressure of a bottoms stream to allow it to boil at a lower temperature. As shown in Figure 5.3, this would allow low-level waste heat to be used to reboil a higher-temperature service.

Potential advantages of heat pump reboiling include:

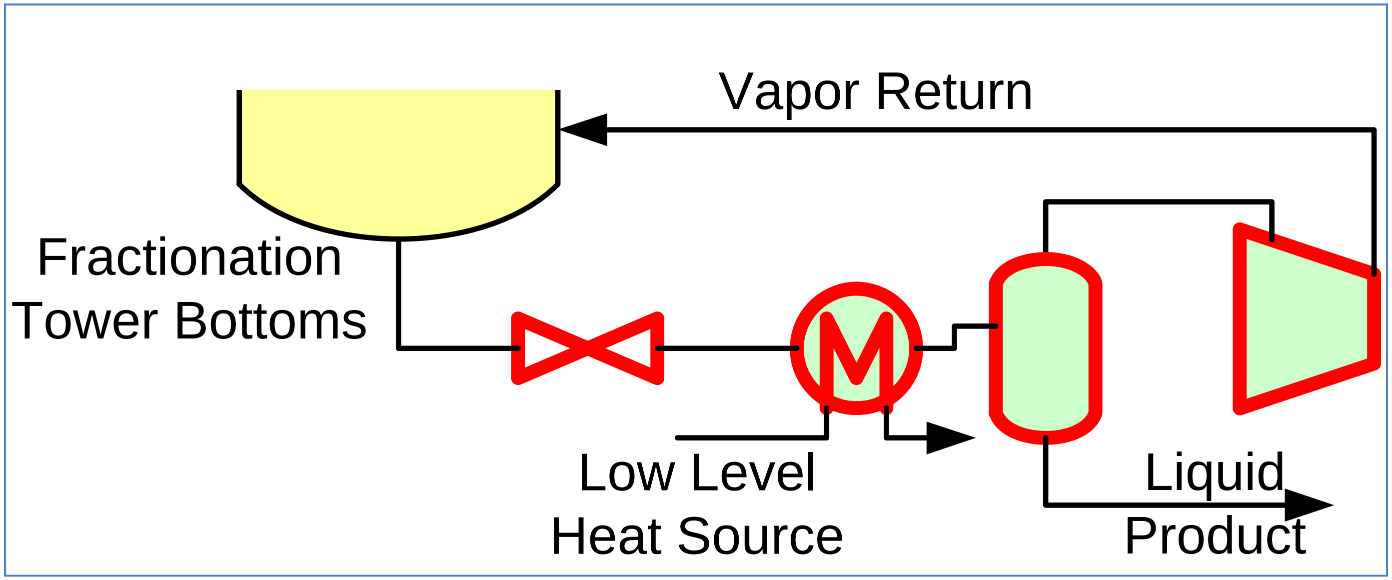
- Increasing waste heat utilization would improve overall energy utilization
- Increasing waste heat recovery would reduce rundown cooling requirements

The disadvantages include:

- There are few upgrader columns that have high enough pressure to take advantage of this service. Typical services would be a propane/butane splitter or debutanizer which are seldom required for upgraders.
- The services that might be considered typically use steam heat which is often waste heat in upgraders.
- The heavier hydrocarbon services in a bitumen upgrader likely would not be suitable for heat pumps because of fouling, hydraulic issues and vapor pressure constraints for low-pressure columns (i.e., vacuum pressure operations probably are not suitable for application of heat pumps).
- A heat pump likely would cost more than the equivalent high temperature reboiler. The utility savings to justify this investment would have to be significant.

The equipment required for a heat pump would be the flash drum and compressor (plus any auxiliary equipment for the compressor). The heat pump exchanger would replace a high temperature reboiler. There might be some savings in air cooling or other cold utility equipment, but that would depend on the energy stream used and the overall heat integration scheme.

Figure 5.3
Heat Pump (Case UG-4)



5.5 Vacuum Column Compressors (Case UG-5)

Typically, vacuum pressure on vacuum distillation unit overhead systems is maintained with steam ejectors and condensers. However, vacuum systems have been designed with compressors or vacuum pumps as opposed to ejectors to make use of low-cost electricity. Figure 5.4 shows a comparison of the two systems.

In addition to the trade-off between steam energy and electric energy, the vacuum compressor system may offer the following potential advantages:

- Since approach temperature is not as critical to performance, vacuum compressors can use air coolers as opposed to water coolers, reducing utility requirements.
- Vacuum compressors are not subject to changes in header pressures or other steam supply issues.
- Vacuum compressors can be located at grade, reducing construction and maintenance costs.
- Steam from vacuum ejectors must be stripped and sent to waste water treating and disposal.

Advantages for the steam system include:

- For most upgrader configurations, medium-pressure steam is generated from waste heat (typically flue gas heat recovery) and does not affect unit boiler loads. Vacuum compressors would require alternate technology selection for hydrogen production or sulfur conversion to eliminate excess steam within the upgrader.
- Ejectors have very high reliability when compared to rotating equipment.
- Ejectors are lower cost than the corresponding compressors.

The equipment requirements are demonstrated in Figure 5.4. Typically three compression stages will be required whether using ejectors or compressors. In addition to the compressor and inter-stage cooling, the compressor system will require knock-out drums and additional compressor auxiliaries. A comparison of Vacuum Unit utility requirements is shown in Table 5.1

Figure 5.4
Vacuum System Comparison (Case UG-5)

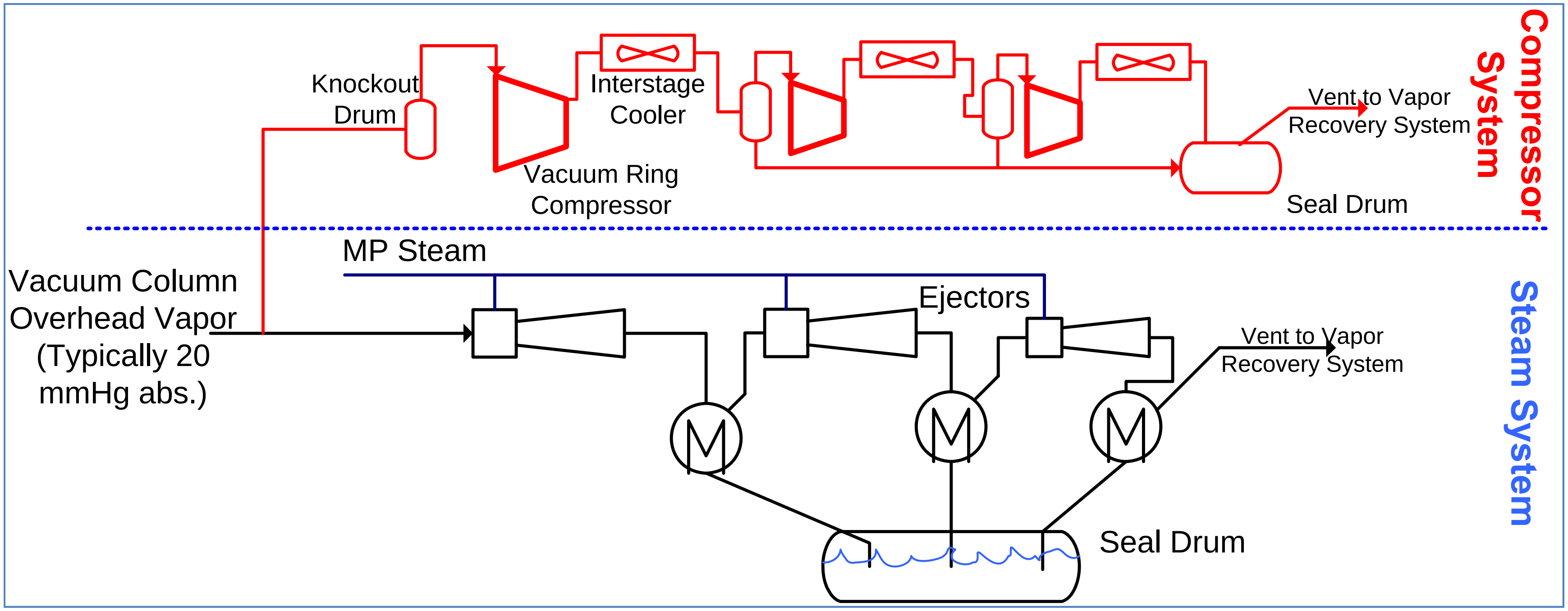


Table 5.1
VDU Total System Utility Requirements

	Steam System	Compressor System
Power Requirements, MW	3.4	4.8
Steam Requirements, Klbs/hr *Includes Sour Water Stripping Steam*	-76.5	-7.5
CW Requirements, m^3/hr	1700	0
GHG Equivalent, MT/Day *Based on Steam Generated from a boiler*	175	61
Water Water Generated, m^3/hr	52	3.4

5.6 Oxygen Enrichment for Combustion (Case UG-6)

Fuel Gas combustion is inefficient primarily because of the need to heat air to combustion temperatures. Efficiency can be improved by increasing the heat recovered from flue gas, but adding oxygen to the air is a more direct way to improve efficiency. Oxygen enrichment reduces the amount of nitrogen that needs to be heated, directly reducing air heating requirements. While there are multiple oxygen enrichment processes, the common commercial processes require electrical power for compression and/or refrigeration.

In addition to the efficiency benefits, oxygen enrichment also has the following benefits:

- Heater equipment, stacks and flue gas recovery systems can be made smaller
- Retrofit of carbon capture technology becomes significantly simpler

Challenges associated with combustion with oxygen enrichment include:

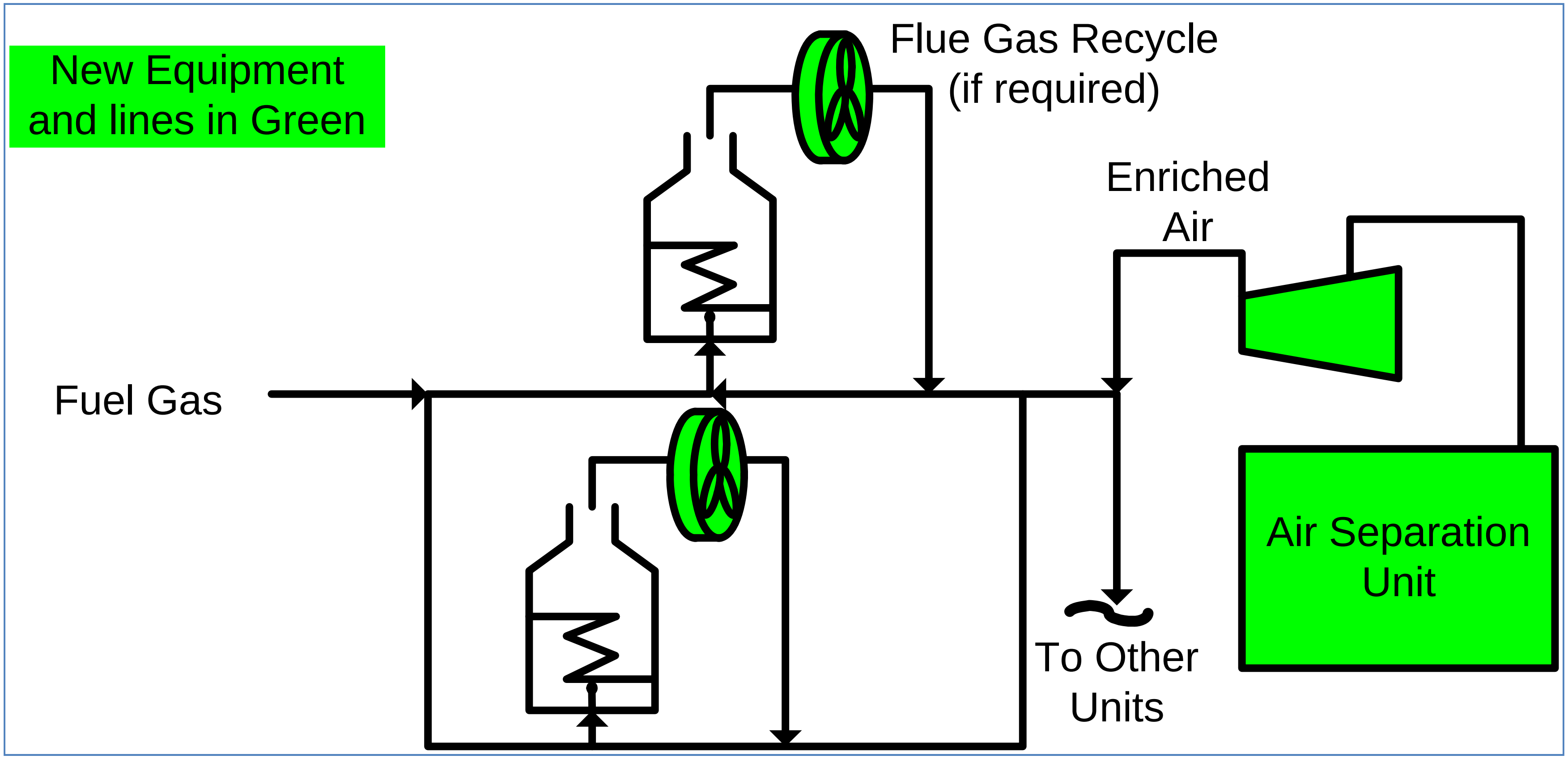
- Oxygen enrichment increases burner and firebox temperatures, potentially requiring metallurgy upgrades and increasing NOX.
- Flue gas recycle is often required both to prevent NOX production and to reduce the temperature at the burners. The flue gas flow prevents any reduction in heater size and increases costs for ducting and rotating equipment.

The additional equipment required for oxygen enrichment includes the oxygen enrichment unit itself.

For this study we assumed a generic Air Separation Unit (ASU) as provided by vendors such as BOC or Air Products. Often enrichment is treated as an operating cost based on a supply contract with the vendor, but in our analysis we included the capital cost for the equipment as well as utility costs.

To identify the size of the potential benefits, we have assumed that oxygen enrichment to 90% concentration could be used and would increase heater efficiency for all units by 10 percent.

Figure 5.5
Oxygen Enrichment for Upgrader Heaters



5.7 Flexicoking™ (Case UG-7)

Flexicoking™ is a process technology, licensed by ExxonMobil, that combines coking with gasification, eliminating a coke product in favor of a synthesis gas or "Flexigas." The process uses electric energy to compress air for coke gasification. The resulting syngas provides process heat and can be used to reduce natural gas imports for other process units.

The potential advantages of Flexicoking™ in upgrading include:

- Coke is typically disposed of in Alberta upgraders as there is no local market. Gasification of coke reduces disposal costs and natural gas imports.
- Compared to gasification, the Flexicoking™ process reduces process systems requirements and should be significantly lower in cost.
- Solids gasification processes can be unreliable due to solids handling issues. Flexicoking effectively removes (or at least reduces) this concern.
- Flexicoking uses air gasification, eliminating the cost of air separation.

The challenges in implementing Flexicoking are:

- The use of air (high nitrogen content) and the low temperature of gasification result in Flexigas having lower energy content than syngas from conventional gasification (125 Btu/scf for Flexigas versus 300 Btu/scf for syngas). Heater designs must be adjusted for this difference and distribution systems will be much larger.
- Flexicoking™ reduces process flexibility and efficiency in recovering high-level energy for power generation and hydrogen production.
- The amount of Flexigas generated from base coke loads will likely exceed natural gas import requirements; thus a use for the extra syngas must be found, or not all of the coke can be gasified.
- Versus delayed coking, Flexicoking economics improve with higher natural gas prices rather than lower power costs.

Figure 5.6 shows a high-level block flow of the Flexicoking process. Table 5.2 shows a comparison of delayed coking and Flexicoking based on vendor-supplied data.

ExxonMobil estimates the cost for a Flexicoker to be about 10-20% more than a delayed coker (Base Case), while an integrated gasifier (the alternate base case for upgrading where IGCC is added) is almost 35% higher in CAPEX than the Base Case.

Figure 5.6
Flexicoking™ Block Flow Diagram

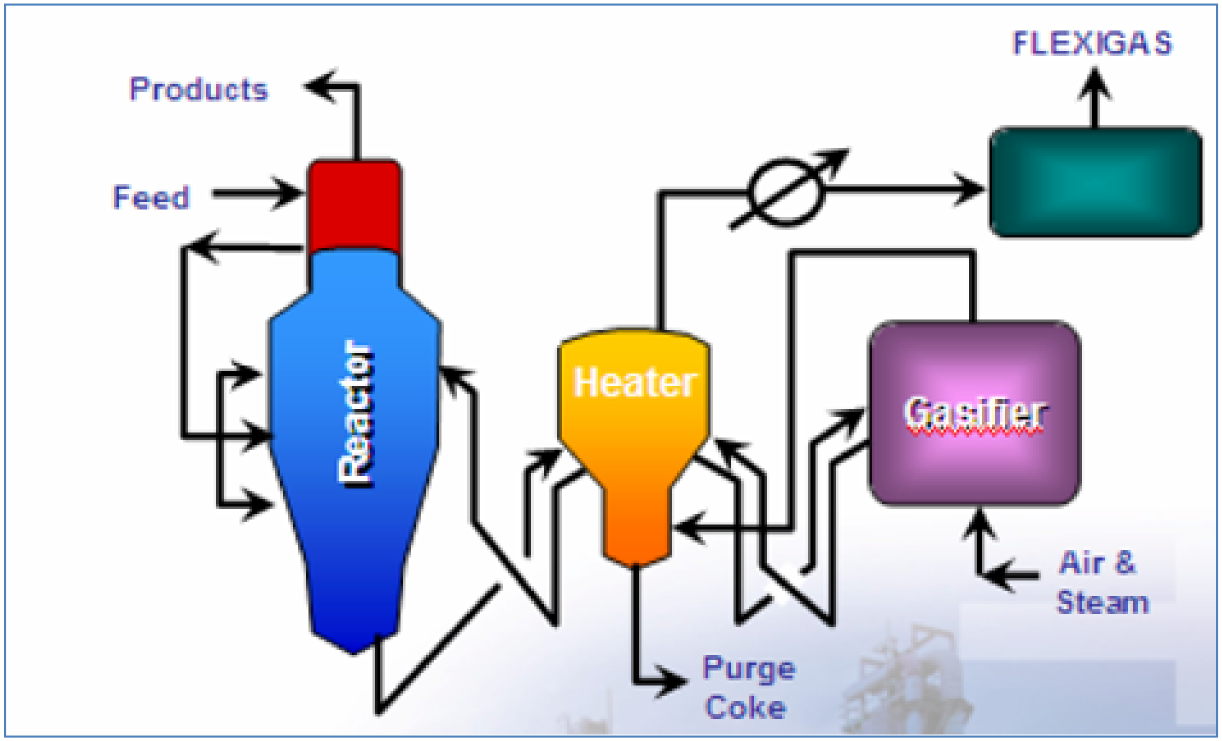


Table 5.2
Comparison of Delayed Coking and Gasification to Flexicoking (Vendor Data)

		Delayed Coker	Delayed Coker + IGCC*	Flexicoker™
Coker Feed Rate	KBPD	101.5	101.5	101.5
Liquid Yields (KBPD)	KBPD	68.5	0	66.99
Fuel Gas Produced	MMBtu/hr	655	655	720
Syngas Produced	MMBtu/hr	0	2,672	5,217
Hydrogen Produced	MMSCFD	0	212	0
Power Requirements **	MW	17.9	-12.8	42.2
Net Coke for Disposal	MT/D	6,246	0	282

* Integrated Gasification Combined Cycle
** Includes Power demand for coker and IGCC less power generated for internal use

6.0 Technology Comparisons

An important aim of the Study was to generate a high-level screen that could be used as the basis to select technologies that might be worthy of a more detailed analysis with respect to true commercial viability. Each technology described in previous sections of this Report was compared to the base cases regarding:

- Estimated Capital Costs (+/- 50%)
- Estimated Operating Costs
- Estimated GHG Emissions
- Opinions of Technical Feasibility
- Effect on Process Yields
- Probable Process Development Period
- Potential Regulatory Issues
- Unit Operation and Facility Availability Risk

As this is a screening-level study, and as agreed with PTAC, these comparisons were based on public domain data.

6.1 SAGD Technologies Capital Cost Comparisons

In Table 6.1 we present a summary of the estimated SAGD facility total installed capital costs for SAGD installations incorporating the technologies under consideration. The novel technology SAGD installations are compared to the SAGD Base Case. We described the SAGD Base Case in Section 3 and the novel technologies in Section 4. All capital costs are order-of-magnitude curve costs with adjustments based on in-house or vendor-supplied equipment cost data. More details of the technology evaluation capital costs and how they were developed for each case are provided in Appendix 1: SAGD Case CAPEX Detail.

As shown in Table 6.1, the changes in total installed capital costs for the new technology SAGD installations are relatively small compared to the Base Case, ranging from about 4% above the Base Case to about 1% below. This is because:

- Steam system and water treating costs are a relatively small percentage of the total facility costs.

- All technologies are fairly well established and thus pricing is competitive with current SAGD facility technologies.
- None of the technologies investigated radically change the overall SAGD process scheme configuration.

Note that differences in capital cost for the various cases are much less than the uncertainty in the overall cost estimates.

Table 6.1
Total Installed Capital Cost Comparisons for SAGD Technologies

	PTAC Base Case	SAGD-1	SAGD-1A	SAGD-2	SAGD-3	SAGD-4	SAGD-5	SAGD-6	SAGD-7
	Base Case [40 kbpcd]	CPF Electric Boilers	CPF Steam Compres-sors	Boilers at Well Pads	Compres-sors at Well Pad	Electric Steam Super-heaters	RO Raw Water Treatment	MVC Evaporators	ZLD
Total Installed Cost ($Million +/- 50%)	$1,965	$2,028	$2,044	$1,939	$1,983	$1,938	$1,975	$1,947	$1,997
Difference from Base Case (New Case - Base)		$63	$79	-$26	$18	-$27	$10	-$18	$32
		+3%	+4%	-1%	+1%	-1%	+1%	-1%	+2%

6.2 SAGD Technologies Operating Cost Comparisons

Table 6.2 is a summary of the estimated SAGD facility total operating costs for SAGD installations incorporating the technologies studied. Total operating costs are a summation of estimated fixed costs and variable costs. Again, we compare the novel technology SAGD installations to the SAGD Base Case. More details of technology evaluation case operating costs and how they were developed for each case are provided in Appendix 2: SAGD Case Operating Cost Detail.

In Table 6.2 we observe that the changes in total operating costs for the novel technology SAGD installations are relatively small, compared to the Base Case, ranging from about 10% above the Base Case to about 7% below.

Breakeven Power Costs Calculation

At the request of PTAC, we calculated an estimated breakeven price of power for each case.

The breakeven price is defined as the price of electricity at which the base case annualized operating costs and the new technology annualized operating costs are the same. During this calculation we held constant the price of natural gas at a value of $4.38 / GJ. We estimated annualized costs by adding total operating costs to 10% of total installed capital costs. (Per agreement with PTAC and to keep this calculation simple, we assumed that natural gas costs did not change as power costs changed. This is a reasonable assumption if one assumes that the reduced power costs would not be the result of natural gas price changes, but use of some other form of low-cost electricity.)

As an example, the annualized breakeven cost for Case SAGD-1 will be the same as the Base Case at a power cost of $19.9 / MW-hr, assuming that the natural gas prices do not change.

A sample breakeven calculation is shown in Appendix 7.

Table 6.2
Total Annual Operating Cost Estimates for SAGD Technologies

	PTAC Base Case	SAGD-1	SAGD-1A	SAGD-2	SAGD-3	SAGD-4	SAGD-5	SAGD-6	SAGD-7
	Base Case [40 kbpcd]	CPF Electric Boilers	CPF Steam Compres-sors	Boilers at Well Pads	Compres-sors at Well Pad	Electric Steam Super-heaters	RO Raw Water Treatment	MVC Evaporators	ZLD
Total Operating Cost ($Million/yr)	$211	$401	$308	$220	$223	$220	$210	$218	$232
Difference from Base Case (New Case - Base)		$190	$98	$9	$12	$9	-$1	$7	$21
		90.4%	46.4%	4.4%	5.8%	4.4%	-0.4%	3.5%	10.0%
Assumed Electricity Price For Base Case and Break Even Price for Each Case ($/MWhr)	$77.2	$19.9	$15.7	$42.5	$6.0	$43.3	$31.3	$35.5	< $0.0

6.3 SAGD Technologies Carbon Footprint Comparisons

Table 6.3 shows the carbon emissions for each case. Direct emissions account for the carbon dioxide generated through combustion of natural gas at the site, while indirect emissions are calculated based on imported electricity.

Indirect emissions are dependent on the fuel and type of power generation plant (e.g., coal, natural gas combined cycle). For Table 6.3, the indirect GHG emissions for each case are shown at three different carbon intensities, including an average value for the Alberta power generating grid (which includes a significant amount of coal-based generation), a value based on electricity from natural gas, and a Canadian power grid average. However, for the sum of direct and indirect emissions, we used only the indirect average Alberta power generation emissions. We observe that all of the SAGD cases have higher total emissions than the Base Case, except for Case SAGD-5, Reverse Osmosis Raw Water Treatment, a minor change in technology from the Base Case.

Table 6.3
Summary of Emissions for SAGD Cases (Carbon Footprint)

		PTAC Base Case (20 kbpcd)	SAGD-1	SAGD-1A	SAGD-2	SAGD-3	SAGD-4	SAGD-5	SAGD-6	SAGD-7
			CPF Electric Boilers	CPF Steam Comps	Boilers at Well Pads	Comps at Well Pad	Electric Steam Super-heaters	RO Raw Water Treat-ment	MVC Evaps	ZLD
Natural Gas	MW	588	59	323	558	564	558	582	582	582
Power	MW	27	450	239	51	51	51	28	43	50
Direct Carbon Emissions	**MT/D**	**2,536**	**254**	**1,395**	**2,409**	**2,435**	**2,409**	**2,511**	**2,511**	**2,511**
% difference from Base Case			**-90%**	**-45%**	**-5%**	**-4%**	**-5%**	**-1%**	**-1%**	**-1%**
Carbon Emissions - Indirect										
@ 880 Kg/MW-hr (Alberta average)	MT/D	564	9,513	5,039	1,069	1,081	1,069	585	912	1,050
@ 511 Kg/MW-hr (Nat Gas electricity)	MT/D	328	5,524	2,926	621	628	621	340	530	610
@ 200 Kg/MW-hr (Canada average)	MT/D	128	2,162	1,145	243	246	243	133	207	239
Direct + Indirect (Alberta) Emissions	**MT/D**	**3,100**	**9,767**	**6,434**	**3,478**	**3,516**	**3,478**	**3,096**	**3,423**	**3,560**
% difference from Base Case			**215%**	**108%**	**12%**	**13%**	**12%**	**0%**	**10%**	**15%**

6.4 Additional Commercialization Criteria for SAGD Technologies

We also evaluated each of the technologies on the basis of five additional criteria that would be critical for successful commercialization:

- Technical Feasibility
- Effect on Process Yields
- Process Development Period
- Potential Regulatory Issues
- Availability Risk

Table 6.4 summarizes the analysis.

Comments on Technical Feasibility

Note that technical feasibility is evaluated without considering economic feasibility. A technology may appear to have technical feasibility but still may not be economically feasible. For example, this may be the case with steam compressors. Technically the concept appears to be viable and is, in fact, in operation in MVC systems. However, economically viable operation for CPF steam compressors and compressors at the well pad may not be possible because of high CAPEX and maintenance costs for compressors and the variability in steam balances which are not conducive to efficient compressor operation.[11]

Comments on Availability Risk

We provide here only a high-level, subjective analysis, based on experience, not a quantitative analysis, which would be far beyond the scope of the Study. Appendix 3, Notes on Operating Risk Issues, contains some general notes related to the operations availability risk for each technology.

[11] The high pressures required for well injection steam require a high compression ratio.

Table 6.4
Summary of Analysis Technical Feasibility, Yield Effect, Process Development Period, Regulatory Issue and Availability Risk Analysis

<table>
<tr><th></th><th>PTAC Base Case</th><th>SAGD-1</th><th>SAGD-1A</th><th>SAGD-2</th><th>SAGD-3</th><th>SAGD-4</th><th>SAGD-5</th><th>SAGD-6</th><th>SAGD-7</th></tr>
<tr><th></th><th>Base Case [40 kbpcd]</th><th>CPF Electric Boilers</th><th>CPF Steam Compres-sors</th><th>Boilers at Well Pads</th><th>Compres-sors at Well Pad</th><th>Electric Steam Super-heaters</th><th>RO Raw Water Treatment</th><th>MVC Evaporators</th><th>ZLD</th></tr>
<tr><td>Technical Feasibility (disregarding economic feasibility)</td><td>Proven</td><td colspan="2">Not proven at scale required for SAGD</td><td colspan="4">Are commercial technologies with applications in petrochemicals, pharmaceuticals, power generation and water treatment industries, but have not been proven in SAGD applications</td><td colspan="2">Have been established for SAGD applications within Alberta.</td></tr>
<tr><td>Affect on Process Yields</td><td></td><td colspan="8">Should not adversely impact SOR, well pad conditions or bitumen processing. Since bitumen production is largely a function of reservoir conditions, production will be retained as long as steam supply and pressure are maintained.</td></tr>
<tr><td rowspan="2">Process Development Period</td><td rowspan="2"></td><td colspan="4">Will potentially require significant testing to prove operation at the scale and conditions required for SAGD operation. Difficult to predict time period at this level of analysis. Most likely multi-years.</td><td colspan="2"></td><td colspan="2" rowspan="2">Already developed for SAGD applications</td></tr>
<tr><td colspan="6">Will require some testing in SAGD facilities to prove there are no compatibility issues. May require multi-years to fully develop.</td></tr>
<tr><td>Potential Regulatory Issues</td><td></td><td colspan="8">None of the technologies increase direct emissions, solids generation or water disposal</td></tr>
<tr><td>Process Availability Risk (in comparison to Base Case)</td><td></td><td>Most likely, no significant risk increase</td><td>Most likely, significant risk increase</td><td>Most likely, significant risk increase</td><td>Most likely, significant risk increase</td><td>Most likely, no significant risk increase</td><td>Most likely, no significant risk increase</td><td>Most likely, no significant risk increase</td><td>Most likely, significant risk increase</td></tr>
</table>

6.5 Conclusions for SAGD Technologies

Table 6.5 compares the eight technology applications to the SAGD Base Case.[12] This table is a summary of the information in tables already presented in this Section.

Remember that the SAGD Base Case definition was consistent with recent Alberta installations and new facility configurations familiar to us. The Base Case is a 40,000 BPSD SAGD facility that uses mechanical lift. Water treating is via Warm Lime Softening (WLS) with Once-Through Steam Generation (OTSG) that produces 80% quality steam. Power supply is assumed to be from the Alberta grid with a carbon emissivity of 880 Kg/MW-hr.[13] The basis for natural gas and power costs were average 2011 Alberta values.[14]

Within the limits of the precision of this analysis, none of the cases demonstrate significantly lower capital costs or lower operating costs than the base case. Most cases have significantly higher total (direct + indirect) carbon emissions. No cases appear to have lower total emissions than the Base Case. There are questions regarding successful application in SAGD for a number of the concepts. Thus at this time, none of the technologies survive the screening process defined for the Study.

If no- or low-carbon emissions electricity became available, at a significantly lower price than today's electricity price (e.g., perhaps, nuclear power), Case SAGD-1 (CPF Electric Boilers), Case 1A (CFP Steam Compressors), Case SAGD-2 (Boilers at Well pad), Case SAGD-3 (Compressors at Well Pad), and Case SAGD-4 (Electric Steam Superheaters) might warrant further analysis. (Base Case economics and emissions would improve also.) Regardless, all of these cases have significant commercialization risk because of varying combinations of technical feasibility, process development and availability risk.

Note Regarding Breakeven Electricity Price Calculation:

A key driver for the low break-even electricity prices is the difference between 2011 Alberta average electricity gate costs at $77.20/MWhr and estimated 2011 Alberta average natural gas gate costs at $4.38/GJ. (Without any corrections for energy use-efficiency the $4.38/GJ natural gas price is equivalent to $15.78/MWhr).[15]

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[12] The number of significant figures used in Table E-1 does not imply a high level of cost and emission estimation accuracy. The high number of significant figures is retained to indicate differences between delta costs (with respect to the base case).

[13] Note that depending on the source of the power, indirect GHG emissions will vary.

[14] These values were used per directions from PTAC. Average 2011 AECO gas prices were adjusted upward by 25% to arrive at gate price estimates.

[15] The electricity price represents an estimated refinery or facility gate price for the user of the electricity. The natural gas price represents an estimated gate price for the user of the natural gas. Use efficiency differences between natural gas energy and electrical energy are incorporated into the Jacobs Consultancy breakeven calculations. (Note: Natural gas heaters are not 100% efficient, whereas electrical heaters are close to 100% efficient.)

Table 6.5
SAGD Case Comparison Summary

<table>
<tr><td rowspan="2">All values are rough estimates. Assuming 880 kg CO2/MWhr emissions from electricity production (current Alberta average). Assuming $77.2/MWhr electricity costs, $4.38/GJ natural gas costs, $15/MT CO2 penalty for direct carbon emissions.</td><td>SAGD Base Case</td><td>SAGD-1</td><td>SAGD-1A</td><td>SAGD-2</td><td>SAGD-3</td><td>SAGD-4</td><td>SAGD-5</td><td>SAGD-6</td><td>SAGD-7</td></tr>
<tr><td>Base Case [40 kbpcd]</td><td>CPF Electric Boilers</td><td>CPF Steam Compressors</td><td>Boilers at Well Pads</td><td>Compressors at Well Pad</td><td>Electric Steam Superheaters</td><td>RO Raw Water Treatment</td><td>MVC Evaporators</td><td>ZLD</td></tr>
<tr><td>Total Installed Cost ($Million +/- 50%) Base Case & Difference from Base Case</td><td>$1,965</td><td>+3%</td><td>+4%</td><td>-1%</td><td>+1%</td><td>-1%</td><td>+1%</td><td>-1%</td><td>+2%</td></tr>
<tr><td>Total Operating Cost ($Million/yr) Base Case & Difference from Base Case</td><td>$211</td><td>+90%</td><td>+46%</td><td>+4%</td><td>+6%</td><td>+4%</td><td>0%</td><td>+4%</td><td>+10%</td></tr>
<tr><td>Direct Carbon Emissions (MTD) Base Case and Difference from Base Case</td><td>2,536</td><td>-90%</td><td>-45%</td><td>-5%</td><td>-4%</td><td>-5%</td><td>-1%</td><td>-1%</td><td>-1%</td></tr>
<tr><td>Direct & Indirect Carbon Emissions (MTD) Base Case & Diff. from Base Case</td><td>3,100</td><td>+215%</td><td>+108%</td><td>+12%</td><td>+13%</td><td>+12%</td><td>+0%</td><td>+10%</td><td>+15%</td></tr>
<tr><td>Electricity Price for Base Case and Breakeven Electricity Price ($/MWhr)**</td><td>$77.2</td><td>$20</td><td>$16</td><td>$43</td><td>$6</td><td>$43</td><td>$31</td><td>$36</td><td>< $0.0</td></tr>
<tr><td>Technical Feasibility (disregarding economic feasibility)</td><td>Proven</td><td colspan="2">Not proven at scale required for SAGD</td><td colspan="4">Are commercial technologies with applications in petrochemicals, pharmaceuticals, power generation and water treatment industries, but have not been proven in SAGD applications</td><td colspan="2">Have been established for SAGD applications within Alberta.</td></tr>
<tr><td>Effect on Process Yields in comparison to Base Case</td><td></td><td colspan="8">Should not adversely impact SOR, well pad conditions or bitumen processing. Since bitumen production is largely a function of reservoir conditions, production will be retained as long as steam supply and pressure are maintained.</td></tr>
<tr><td rowspan="2">Process Development Period</td><td rowspan="2"></td><td colspan="4">Will potentially require significant testing to prove operation at the scale & conditions required for SAGD operation. Difficult to predict time period at this level of analysis.</td><td colspan="2"></td><td colspan="2" rowspan="2">Already developed for SAGD applications</td></tr>
<tr><td colspan="6">Will require some testing in SAGD facilities to prove there are no compatibility issues. May require multi-years to fully develop.</td></tr>
<tr><td>Potential Regulatory Issues</td><td></td><td colspan="8">None of the technologies increase direct emissions, solids generation or water disposal. All new technologies may invite increased regulatory scrutiny.</td></tr>
<tr><td>Process Availability Risk, in comparison to Base Case</td><td></td><td>No significant risk increase</td><td>Significant risk increase</td><td>Significant risk increase</td><td>Significant risk increase</td><td>No significant risk increase</td><td>No significant risk increase</td><td>No significant risk increase</td><td>Significant risk increase</td></tr>
</table>

** **Note:** The break-even price is defined as the price of electricity at which the base case annualized full operating costs and the new technology annualized full operating costs are the same. During this calculation the price of natural gas was held constant at the value of $4.38 / GJ. Full annualized costs were estimated by adding fixed and variable operating costs to 10% of total installed capital costs.

Note Regarding Small Changes in Capital Costs and Operating Costs among Cases:

The percentage differences between the electricity technology cases and the Base Case are smaller than the level of accuracy of the Base Case capital cost estimate. The capital cost differences among the cases often are due to changes in a few key pieces of equipment. Thus the cost differences tend to be more meaningful than the absolute values of the total plant costs. Regardless, we are looking at small differences between two large numbers that are imprecise. Therefore we advise caution when discriminating among the cases on the basis of percentage changes when the percentage changes are small. The same argument applies for differences in operating costs.

Most of the electric technology applications suffer from a lack of sufficient commercial large-scale operation in the service intended. The economics of all of the electric technology applications would benefit from the availability of low-priced, low-emissions electric power. The following additional comments are offered for each SAGD case:

SAGD-1 Case, CPF Electric Boilers: High power costs and high indirect emissions levels have a negative effect on this case. This technology would, most likely, require significant testing and development, given limited industry experience with electric boilers at this scale.

SAGD-1A Case, CPF Steam Compressors:[16] High power costs, relatively high capital costs, and high indirect emissions levels have a negative effect on this case.[17] This technology likely would require significant testing and development given the limited industry experience with steam compressors at this scale, as there are no known examples of steam compressors at the required scale and compression ratio. Also, there is potential for lower process availability because of the addition of high temperature rotating equipment.

SAGD-2 Case, Boilers at Well Pads:[18] High power costs and high indirect emissions levels have a negative effect on this case. This technology likely would require significant testing and

[16] The reason for looking at steam compressors at the CPF is to investigate the possibility that waste steam from blowdown or produced water flashing could be recovered to produce high pressure steam, reducing TOTAL production energy. The problem with this premise is that pinch analysis shows that there is no waste heat in the appropriate temperature range in the SAGD facility, so there is little efficiency gain. Actually,, flashing steam increases the heat load on the steam generators. In addition, compressor costs are high in relation to the expected economic efficiency gains, especially at the compression ratio required for SAGD.

[17] Steam compressors typically are more expensive and less energy efficient than pumps and boiler systems for generating high pressure steam. While there is extensive operating experience with compressors, their use for steam generation is limited to processes with unique heat integration characteristics and they typically require more maintenance and operator interaction than boilers.

[18] In the Base Case, steam line condensate is mixed with emulsion at the well pad and returned to the CPF. If we could re-vaporize the condensate and return it to the steam header, we could eliminate the recycle and re-treatment of water, effectively reducing the size of the CPF and increasing operation efficiency.

development given limited industry experience with electric boilers for this application. Also, process availability risk would be increased by the additional equipment in dispersed locations.[19]

SAGD-3 Case, Compressors at Well Pad:[20] As described for the use of compressors at the CPF, the concept here is to explore the possibility that waste steam from blowdown or produced water flashing could be recovered to produce high-pressure steam. However, this case has higher operating costs and higher total emissions compared to the Base Case. The process availability risk would be increased by the addition of high temperature rotating equipment, especially in dispersed locations.

SAGD-4 Case, Steam Superheaters: As with well pad boilers, steam superheaters would lower CPF costs by increasing the amount of steam delivered to the well pads. Steam superheating could be accomplished by electric steam superheaters, natural gas superheating, or flue gas exchangers, depending on energy prices. Electric steam superheating would become more economic as power cost and emissions are reduced relative to natural gas. Superheating likely would be preferable to well pad boilers because implementation, required operator attention, and maintenance should all be less costly at the CPF than in the field.

SAGD-5 Case, Reverse Osmosis for Make-up Water Treating: Make-up water treating reduces operating costs by improving heat integration and eliminating direct steam injection.[21] This case shows no net total operating cost increase or GHG emissions increase versus the Base Case.

Moreover, RO does not appear to offer significant benefits in terms of reducing overall water consumption or lowering GHG emissions. There might be a need for process development prior to commercialization, but RO systems have been implemented in other brackish water applications.

SAGD-6 Case, MVC Evaporators for Produced Water: MVC evaporators have been used in commercial SAGD facilities both for produced water and for blowdown treating. Their usage in Alberta has been limited, primarily because of the increased power consumption relative to Warm Lime Softening.

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[19] We expect that this application would require additional process control instrumentation and more operator's time to monitor and control the well-pad equipment to ensure that the boilers remain operative and do not interfere with well pad production. Since there are multiple well pads widely dispersed throughout the field, this amounts to a higher operating cost and, most likely, additional risk exposure.

[20] The reason for looking at steam compressors at the well pad is the same reason we would consider boilers, which is to recover and re-vaporize condensate. The problem with compressors in this case is that they do not offer any efficiency gains for liquid water. Flashing the water means we would recover only a small portion of the condensate, returning the rest to the CPF.

[21] Direct steam injection, or a "pick" heater, is used to heat brackish water without the need for heat exchange. Heat exchangers used for brackish water foul quickly as brackish water is heated above 50°C. Use of a pick heater avoids this issue by heating the water to 85° in a Teflon lined section of pipe immediately upstream of the water treating feed tank.

However, evaporators have significant advantages in terms of water utilization, and applications in SAGD have been commercially proven. If power cost and indirect emissions are low enough, MVC evaporators (with package drum boilers) would compare favourably with WLS/OTSG. Also, future regulations may make this option more attractive if stricter water use/ disposal limits are imposed.

SAGD-7 Case, Zero-Liquid Discharge (ZLD): We have studied ZLD technology for several clients and have found neither economic reasons nor significant water use reductions to warrant considering ZLD. ZLD evaporators increase operating complexity and reduce unit availability. ZLD might be considered if there are future limitations on liquid waste disposal imposed by regulation.

6.6 Upgrading Technologies Capital Cost Comparisons

In Table 6.6 we present a summary of the estimated upgrading facility total installed capital costs for installations incorporating the technologies studied. The novel technology upgrading installations are compared to the upgrading Base Case. We described the upgrading Base Case in Section 3 and the novel technologies for upgrading in Section 5. All capital costs are order-of-magnitude curve costs with adjustments based on in-house or vendor-supplied equipment cost data. More details of technology evaluation case capital costs and how they were developed for each case are provided in Appendix 4: Upgrading Case CAPEX Detail.

As we see in Table 6.6 the electrolytic hydrogen (UG-1), oxygen enrichment (UG-6) and Flexicoking (UG-7) cases have significantly higher CAPEX than the Base Case. The remaining cases show relatively small or no significant changes in estimated capital cost.

Table 6.6
Total Installed Cost Comparisons for Upgrading Technologies

	PTAC Base Case	UG-1	UG-2	UG-3	UG-4	UG-5	UG-6	UG-7
	No gasifier [200 kbpd]	H2 production Via Electrolysis	Electric Heaters	Hot Oil System	Heat Pump	Vacuum compressor	Oxygen Enrichment	Flexicoking and syn-gas H2
Total Installed Cost ($Million +/- 50%)	$5,460	$6,000	$5,540	$5,550	$5,550	$5,460	$5,870	$6,220
Difference from Base Case (New Case - Base)		**$540**	**$80**	**$90**	**$90**	**$0**	**$410**	**$760**
		+10%	**+1%**	**+2%**	**+2%**	**0%**	**+8%**	**+14%**

6.7 Upgrading Technologies Operating Cost Comparisons

Table 6.7 is a summary of the estimated upgrading facility total annual operating costs for installations incorporating the technologies under evaluation. Total operating costs are a summation of estimated fixed costs and variable costs. Again, we compare the novel technology upgrading installations to the upgrading Base Case. More details of the technology evaluation case operating costs and how they were developed for each case are provided in Appendix 5: Upgrading Case Operating Cost Detail.

In Table 6.7 we observe that the estimated operating costs for the electrolytic hydrogen production case (UG-1) are much higher than the Base Case due to additional electricity costs. The operating costs for the enriched oxygen case (UG-6) are somewhat higher than the Base Case, while the estimated operating costs for the other cases are similar to the Base Case.

Breakeven Power Cost Calculation

At the request of PTAC we calculated an estimated breakeven price of power for each case.

The breakeven price is defined as the price of electricity at which the base case annualized operating costs and the new technology annualized operating costs are the same. During this calculation we held constant the price of natural gas at $4.38 / GJ. Annualized costs were estimated by adding total operating costs to 10% of total installed capital costs. (Per agreement with PTAC and to keep this calculation simple, we assumed that natural gas costs did not change as power costs changed. This is a reasonable assumption if one assumes that the reduced power costs would not be the result of natural gas price changes, rather, for example, the result of nuclear-powered electricity generation plants.)

As an example, the annualized breakeven cost for Case UG-1 will be the same as the Base Case at a power cost of $6 / MW-hr, assuming that the natural gas prices do not change.

In Table 6.7 we calculate the breakeven costs analysis for Case UG-7 (Flexicoking) on the basis of comparison to an upgrader without a gasifier. The breakeven analysis for Case UG-7 versus the upgrader with a gasifier yields a breakeven value of $140.5 / MW-hr. This compares to $82.4 / MW-hr for the comparison against the base case without a gasifier. Note that the base case with the gasifier has a higher total installed cost than Case UG-7. Also note that the gasifier base case does not have power exports, but is generating all of the facility power demand.

Table 6.7
Annual Operating Cost Comparisons for Upgrading *Technologies*

	PTAC Base Case	UG-1	UG-2	UG-3	UG-4	UG-5	UG-6	UG-7
	No gasifier [200 kbpd]	H2 production Via Electrolysis	Electric Heaters	Hot Oil System	Heat Pump	Vacuum compressor	Oxygen Enrichment	Flexicoking and syn-gas H2
Total Operating Cost ($Million/yr)	$618	$1,340	$661	$667	$637	$640	$748	$537
Difference from Base Case (New Case - Base)		**$722**	**$43**	**$49**	**$19**	**$22**	**$130**	**-$81**
		+117%	**+7%**	**+8%**	**+3%**	**+4%**	**+21%**	**-13%**
Assumed Electricity Price For Base Case and Break Even Price for Each Case ($/MWhr)	**$77**	**$7**	**$0**	**$10**	**$0**	**$19**	**$0**	**$82**

6.8 Upgrading Technologies Carbon Footprint Comparisons

Table 6.8 shows the carbon emissions for each upgrading case. Direct emissions account for the carbon dioxide generated through combustion of natural gas on site, while indirect emissions are calculated based on imported electricity.

Indirect emissions are dependent on the fuel and type of power generation plant (e.g., coal, natural gas combined cycle). For Table 6.8, the indirect GHG emissions for each case are shown at three different carbon intensities, including an average value for the Alberta power generating grid, a value based on electricity from natural gas, and a Canadian power grid average. However, for the sum of direct and indirect emissions, we used only the indirect average Alberta power generation emissions.

All of the cases to varying degrees consume less natural gas and more electricity than the Base Case. We observe that all of the upgrading cases have higher total emissions than the Base Case. The electrolytic hydrogen case total emissions are nearly three times higher than the Base Case.

Table 6.8
Summary of Emissions for Upgrading Cases (Carbon Footprint)

		Upgrader Base Case (200 kbpcd)	UG 1	UG 2	UG 3	UG 4	UG 5	UG 6	UG 7
			Electro-lytic Hydrogen	Electric Reboiler	Hot Oil System	Heat Pump	Vacuum Pump	Oxygen Enrich-ment	Flexi-coking™
Natural Gas	MW	1,531	453	1,395	1,324	1,463	1,413	1,413	8
Power	MW	100	1,410	174	203	122	145	274	224
Direct Carbon Emissions	**MT/D**	**11,178**	**3,527**	**10,640**	**10,337**	**10,909**	**10,711**	**10,831**	**11,812**
% difference from Base Case			**-68%**	**-5%**	**-8%**	**-2%**	**-4%**	**-3%**	**6%**
Carbon Emissions - Indirect									
@ 880 Kg/MW-hr (Alberta average)	MT/D	2,102	29,778	3,669	4,296	2,572	3,052	5,786	4,729
@ 511 Kg/MW-hr (Nat Gas electricity)	MT/D	1,221	17,292	2,131	2,495	1,494	1,773	3,360	2,746
@ 200 Kg/MW-hr (Canada average)	MT/D	478	6,768	834	976	585	694	1,315	1,075
Direct + Indirect (Alberta) Emissions	**MT/D**	**13,280**	**33,305**	**14,309**	**14,633**	**13,481**	**13,764**	**16,617**	**16,541**
% difference from Base Case			**151%**	**8%**	**10%**	**2%**	**4%**	**25%**	**25%**

6.9 Additional Commercialization Criteria for Upgrading Technologies

We evaluated each of the technologies on the basis of five additional criteria that would be critical for successful commercialization:

- Technical Feasibility
- Effect on Process Yields
- Process Development Period
- Potential Regulatory Issues
- Availability Risk

Table 6.9 summarizes the analysis.

Comments on Technical Feasibility

Note that as for SAGD technologies, Technical Feasibility was evaluated without considering economic feasibility. A technology may appear to be technically feasible but still may not be economically feasible.

Comments on Availability Risk

We provide here only a high-level, subjective analysis, based on experience, not a quantitative analysis, which would be far beyond the scope of the Study. Appendix 6 (Upgrading Case Operating Risk Issues) contains some general notes related to the operations risk assessment for each technology.

Table 6.9
Summary of Analysis Technical Feasibility, Yield Effect, Process Development Period, Regulatory Issue and Availability Risk Analysis

	PTAC Base Case	UG-1	UG-2	UG-3	UG-4	UG-5	UG-6	UG-7
	No gasifier [200 kbpd]	H2 production Via Electrolysis	Electric Heaters	Hot Oil System	Heat Pump	Vacuum compressor	Oxygen Enrichment	Flexicoking and syn-gas H2
Technical Feasibility (disregarding economic feasibility)	Proven	Not proven at scale required for bitumen upgrading	Has been widely used in oil refining and petrochemicals, but have not been applied in bitumen upgraders.	The feasibility of electric heavy oil heating and heat pumps for heavy oil distillation needs to be proven.		Has been widely used in oil refining and petrochemicals, but has not been applied in bitumen upgrader.	Has been used for specific applications and heaters, but we have no knowledge of a facility wide enrichment system.	Has been widely used in oil refining and petrochemicals, but have not been applied in bitumen upgrader.
Affect on Process Yields		Should not adversely impact Yield.						Will change the refinery yield, most likely reducing the amount of SCO produced. The specifics of the feed stocks and desired coke yield would have to be verified with the licensor to determine how significant the yield shift
Process Development Period		Testing at scale would be required to establish that this technology can be economically used for upgrading.	Would require pilot testing					None
Potential Regulatory Issues		Will reduce site emissions						Will increase site emissions
Process Availability Risk (in comparison to Base Case)		Most likely, no significant risk increase	Since there is little refining industry experience, the reliability in heavy hydrocarbon service must be established.	Has the potential to increase reliability by sustaining operation during steam system or fired heater failures.	Most likely, moderate risk increase	Should not excessively increase the operating risk	Oxygen enrichment will likely increase operator and maintenance responsibility, negatively impacting upgrader operating risk.	Relative to delayed coking, Flexicoking™ will likely increase operator and maintenance responsibility, negatively impacting upgrader operating risk.

6.10 Conclusions for Upgrading Technologies

Table 6.10 summarizes the comparison of the seven technology applications to the Bitumen Upgrading Base Case.[22]

Remember that the Bitumen Upgrading Base Case definition was consistent with some recent Alberta installations and upcoming facility configurations that are familiar to us. The base case is a 200,000 BPSD Bitumen unit that incorporates the following key unit operations: DRU, VDU, Delayed Coker, Naphtha & Diesel Hydrotreaters, Mild Hydrocracker, and a Steam Methane Reforming Hydrogen Plant. The upgrader produces an SCO with approximately 31° API, 40 Diesel cetane level and 38% Gasoil level. The required power supply is assumed to be from the Alberta grid with a carbon emissivity of 880 Kg/MW-hr. The basis for natural gas and power costs were average 2011 Alberta values.[23]

Within the limits of the precision of this analysis, none of the cases demonstrate significantly lower capital costs than the Base Case. Only Case UG-7, Flexicoking, has lower estimated operating costs. All of the cases have significantly higher total (direct + indirect) carbon emissions. There are questions regarding successful application in upgrading for a number of the concepts. Thus at this time, none of the technologies survive the screening process defined for the Study.

If no- or low-carbon emissions electricity became available, at a significantly lower price than today's electricity price (e.g., perhaps, nuclear power), Case UG-5 (Vacuum Compressor) might deserve further analysis. We recommend a more detailed review of Case UG-3 (Hot Oil System) as there may be capital and operating benefits not recognized in this Study. All these cases probably would require some process development and pilot testing to prove feasibility.

Note Regarding Breakeven Electricity Price Calculation

A key driver for the low breakeven electricity prices is the difference between 2011 average electricity costs ($77.20/MWhr) and natural gas costs ($15.78/MWhr or $4.38/GJ).

[22] The number of significant figures used in Table E-2 does not imply a high level of cost and emission estimation accuracy. The high number of significant figures is retained to indicate differences among costs (with respect to the base case).

[23] Per directions from PTAC. AECO gas price adjusted upward by 25% to arrive at gate price estimate.

Table 6.10
Upgrading Case Comparison Summary

All values are rough estimates. Assuming 880 kg CO2/MWhr emissions from electricity production (current Alberta average). Assuming $77.2/MWhr electricity costs, $4.38/GJ natural gas costs, $15/MT CO2 penalty for direct carbon emissions.	**PTAC Base Case** No gasifier [200 kbpd]	**UG-1** **H2 Production Via Electrolysis**	**UG-2** **Electric Heaters and Reboilers**	**UG-3** **Hot Oil System**	**UG-4** **Heat Pump**	**UG-5** **Vacuum Compressor**	**UG-6** **Oxygen Enrichment**	**UG-7** **Flexicoking and Syn-gas H2**
Total Installed Cost ($Million +/- 50%) Base Case & Difference from Base Case	**$5,460**	**+10%**	**+1%**	**+2%**	**+2%**	**0%**	**+8%**	**+14%**
Total Operating Cost ($Million/yr) Base Case & Difference from Base Case	**$618**	**+117%**	**+7%**	**+8%**	**+3%**	**+4%**	**+21%**	**-13%**
Direct Carbon Emissions (MTD) Base Case and Difference from Base Case	**11,178**	**-68%**	**-5%**	**-8%**	**-2%**	**-4%**	**-3%**	**6%**
Direct & Indirect Carbon Emissions (MTD) Base Case & Diff. from Base Case	**11,742**	**184%**	**22%**	**25%**	**15%**	**17%**	**42%**	**41%**
Electricity Price for Base Case and Breakeven Electricity Price ($/MWhr)	**$77**	**$7**	**$0**	**$10**	**$0**	**$19**	**$0**	**$82**
Technical Feasibility (disregarding economic feasibility)	Proven	Not proven at scale required for bitumen upgrading	Has been widely used pharma, foods, petchems, but not in refining and bitumen upgraders.	The feasibility of electric heavy oil heating and heat pumps for heavy oil distillation needs to be proven.		Has been widely used in oil refining and petrochemicals, but has not been applied in bitumen upgrader.	Has been used for specific applications and heaters, but we have no knowledge of a facility wide enrichment system.	Has been widely used in oil refining and petrochemicals, but have not been applied in bitumen upgrader.
Effect on Process Yields		Should not adversely impact yields.						Will change the refinery yield, most likely reducing the amount of SCO produced. The specifics of the feed stocks and desired coke yield would have to be verified with the licensor to determine how significant the yield shift is.
Process Development Period		Testing at scale would be required to establish that this technology can be economically used for upgrading.	Would require pilot testing					None
Potential Regulatory Issues		Will reduce site emissions						Will increase site emissions
Process Availability Risk (in comparison to Base Case)		Most likely, no significant risk increase	Since there is little refining industry experience, the reliability in heavy hydrocarbon service must be established.	Has the potential to increase reliability by sustaining operation during steam system or fired heater failures.	Most likely, moderate risk increase	Should not excessively increase the operating risk	Oxygen enrichment will likely increase operator and maintenance responsibility, negatively impacting upgrader operating risk.	Relative to delayed coking, Flexicoking™ will likely increase operator and maintenance responsibility, negatively impacting upgrader operating risk.

** **Note:** The break-even price is defined as the price of electricity at which the base case annualized full operating costs and the new technology annualized full operating costs are the same. During this calculation the price of natural gas was held constant at the value of $4.38 / GJ. Full annualized costs were estimated by adding fixed and variable operating costs to 10% of total installed capital costs.

Note Regarding Small Changes in Capital Costs and Operating Costs between Cases:

The percentage differences between the electricity technology cases and the Base Case are smaller than the level of accuracy of the Base Case capital cost estimate. The capital cost differences among the cases often are due to changes in a few key pieces of equipment. Thus the cost differences tend to be more meaningful than the absolute values of the total plant costs. Regardless, we are looking at small differences between two large numbers that are imprecise. Therefore we advise caution when discriminating among the cases on the basis of percentage changes when the percentage changes are small. The same argument applies for differences in operating costs.

The following additional comments are offered for each case.

UG 1 Case, Electrolytic Hydrogen Production: Although this is a proven technology, the capital costs for electrolytic hydrogen facilities are high, based on estimates from two technology suppliers. The current scale of the technology is so low compared to the needs of a typical upgrader that the unit land-use footprint might be an issue.[24]

Operating costs are high, based on current Alberta power costs. There might be some potential for technology innovation that would increase unit operation train size, decrease capital costs and decrease land use footprint, but it appears unlikely that the degree of these innovations would make this option economically and environmentally attractive.

UG 2 Case, Electric Process Heaters: Electric process heaters are not used in refining applications because capital and operating costs are higher relative to fuel-fired heating. In addition to economic constraints, this technology must overcome process concerns about coking in heavy oil applications, since heat fluxes and temperatures of surfaces in contact with heavy oil likely would be higher than is normal for fuel-fired heaters.

UG 3 Case, Hot Oil Systems: Using electric power to heat hot oil is known in petrochemical applications and should be easy to adapt to upgrading. The level to which fired heat can be replaced by hot oil would have to be studied in more detail to determine the limits of each application. We recommend a more detailed review of this application as there may be capital and operating benefits not recognized in this Study.

UG 4 Case, Heat Pump: Heat pump applications are more applicable to light hydrocarbon and petrochemical applications. Heat pumps are applicable in the areas of distillation where (a) the reboiler is operating at a high enough pressure to allow a let-down to pressures above atmospheric, and (b) there is a waste heat source available to reboil the material at a lower

[24] At minimum, hundreds of modules would be required, based on today's unit operation train size.

pressure and temperature. There appear to be very few applications within an upgrading facility that meet these criteria. For example, in this study, we have assumed a debutanizer column for the Mild Hydrocracker but the debutanizer is not a good application for a heat pump because of the presence of heavier hydrocarbons.

UG 5 Case, Vacuum Compressor: Vacuum compressors or vacuum pumps in place of vacuum column steam ejectors reduce upgrader steam demands through the use of imported electricity. This results in a net reduction of energy input due to the higher efficiency of the compressors versus steam ejectors. In addition, vacuum pumps often are used in place of ejectors in refineries.

Low-priced and low GHG emission level electricity would improve the economics of this option. Current commercial use of these systems in similar services renders reliability risk and availability risk low.

UG 6 Case, Oxygen Enrichment: Oxygen enrichment for fired heaters is considered in applications for carbon capture where the intent is to increase the concentration of carbon dioxide in the stream to be processed. However, beyond this reason there is little economic or environmental incentive to consider this option. Oxygen enrichment increases total capital cost and energy inputs for the upgrader, and it is unlikely that it would be economically or environmentally justified without carbon capture credits.

UG 7 Case, Flexicoking™: Replacing delayed coking with Flexicoking™ offers many of the advantages of gasification such as utilizing an inexpensive feed source and having low variable operating costs, but with a lower overall capital cost. However, using coke as a fuel source creates more carbon emissions. Finally, the complexity of this option along with perceived risks in availability and reliability need careful consideration.

7.0 Electricity-Based In-Situ Bitumen Production Technologies

The potential for the use of electrical heating technologies for bitumen production has been recognized since the 1970s. Since that time, but mostly in the 1980s and 1990s, various technical universities, research institutes, energy majors and some entrepreneurial firms conducted R&D work and some small field studies with (on the basis of public domain accounts) marginal success.

Recently, there has been a renewal of efforts in this arena. A few entrepreneurial firms or organizations, such as ET-Energy or the ESEIEH consortium, have progressed technologies to the point where they have begun or are close to beginning new R&D tests and field studies with the support of the Alberta government, European energy majors, and Province-funded non-government organizations.

For the high-level screening-type analysis of the Study, we surveyed the range of potential electrical technology approaches that might apply to bitumen extraction from oil sands[25], and within this range we reviewed and compared the most notable technologies that are being proposed for SAGD replacement today. Because the emerging technologies for electrical in situ bitumen production are at a much earlier stage of development, sufficient details were not available for us to apply the same detailed evaluation criteria used for SAGD and upgrading cases. Instead, for these technologies we developed a qualitative assessment of the state of technology development, the organizations involved, and the prospects for continued progress toward commercialization.

We see positive and negative aspects for each technology. There are high levels of uncertainty in (1) the lack of detailed operating and capital cost information in the public domain, and (2) the lack of long-term field test runs. Nonetheless, we make suggestions regarding the relative merits of each technology and suggestions for more detailed analysis that might help to better differentiate the relative potential of these technologies even at this pre-demonstration stage.

7.1 Technical Background

There are 3 different electrical process methods that have been used to heat and extract bitumen from Oil Sands in production R&D trials and pilot tests:

- Resistance heating
- Dielectric heating

[25] Processes focusing on extracting bitumen from carbonate formations were excluded, per agreement with PTAC.

- Induction heating

None of these methods have yet seen routine commercial use for bitumen production. The general characteristics of each of these methods are discussed below.

7.1.1 Resistance (Ohmic) Heating

Principle of Operation

In this approach low frequency alternating current is used. There have been two approaches to this method.

- **Type 1: Use of isolated resistance heaters:** Insertion of electrical resistance heaters, powered by low frequency alternating current, into bitumen field holes. In these systems there is no current flow in the field (under normal operation).
- **Type 2: Using the bitumen field as a current carrying medium:** This method uses low frequency currents that cross a production field from one down-hole electrode to another to generate heat based on resistance—in the field material—to the flow of the electric current from one electrode to the other. More than two electrodes may be used per "cell," such as in a three-phase system. The electric current travels (primarily via ionic conduction) through interstitial water present in or added to the bitumen reservoir matrix. Electrical energy is converted into heat energy via associated ohmic (resistive) losses in the formation.

Temperature control at the electrode surface is an issue. For at least one technology application, water injection at the electrode tip has been used as a means to control temperature.

As Vermeulen and McGee note in one of their academic papers on the subject,

> " Due to the inherent geometry of current flow emanating from an electrode, current densities and heating rates are highest near the electrodes. Care must be taken lest the water in the immediate vicinity of the electrodes vaporizes and the continuous water path between electrodes is broken. Hence, power frequency heating is generally appropriate when the desired temperatures to be achieved in the formation are lower than the in situ steam temperature."[26]

[26] In Situ Electromagnetic Heating for Hydrocarbon Recovery and Environmental Remediation, *Journal of Canadian Petroleum Technology*, August 2000, Volume 39, No. 8.

The current embodiment of Vermeulen and McGee's technology (under development by ET-Energy) pumps water down the electrode tube, into the reservoir, to cool the electrode tip surface.

The key effect of the heat generation is to reduce the viscosity of the bitumen. This improves the mobility of the bitumen and makes it easier to pump it to the surface. The existing or added water also helps to transfer heat through the matrix.

Historical R&D

There are records of R&D work on heavy oil production process development using the resistance heating technique as far back as the early 1960s, in California and Russia. ARCO, Petro-Canada, UENTECH, the US DOE and the IIT Research Institute (IITRI) of Chicago tested resistive heating systems for heavy oil or bitumen production in the 1970s and 1980s.

Firms Currently Developing Resistance Heating Technology

ET-Energy of Alberta currently is developing a bitumen production process that is based on resistance heating. It is the only firm we have found in a public domain information screen that is actively engaged in technology business development for a resistance type process.

Potential Benefits of Method (based on public domain information and internal analysis)

- No need for natural gas and steam generation.
- Much lower direct GHG emissions. Total emissions would be lower if low-emission power generation method was used.
- Very little, if any, net added water is required.
- Allows bitumen extraction in areas too deep for mining and too shallow for SAGD.

Potential Problems with Method (based on public domain information and internal analysis)

- Does not achieve volumetric heating of reservoir volume[27]
- Increased offsite GHG emissions (related to electricity production from coal or natural gas)

[27] With resistance heating, heat generation occurs only along the route of current flow. With volumetric-type heating, such as what one theoretically observes with electromagnetic radiation-type extraction methods (See ESEIEH Technology), heat generation occurs over a wider volume, due to the exposure of the entire surrounding formation to the special frequency of electromagnetic radiation (with the effects of exposure diminishing with distance from the source).

- For the Type 1 isolated resistance heater approach, high surface temperatures are required for transfer of reasonable amounts of heat/unit time from the wellbore region. These high temperatures cause thermal conversion of surrounding bitumen, thermal degradation of insulating materials and often failure of the device.
  - As a result, the Type-1 type of electrical heater is no longer commonly used in the petroleum industry. (This over-heating issue is claimed *not* to be an issue with the ET-Energy version of this general method, where the bitumen field serves as the current carrying material. The ET-Energy technology - per claims - eliminates or reduces the negative effects of high temperature near anodes and cathodes, by injection of water at the electrode tips.)
- Oil reservoirs are not homogeneous and often are formed of layers of sediment of different physical and electrical characteristics. Theoretically, this may lead to uneven heating. The resistivities of oil bearing reservoirs can vary greatly depending on their porosity and their saturation with oil, water, and gas. Also, the resistivity of the formation declines as its temperature increases. This issue could affect both Type 1 and Type 2 systems.

7.1.2 Dielectric Heating

This technique also has been called:

- RF (radio frequency) heating
- Capacitance heating
- Diathermy
- Microwave heating, *or*
- High radio-frequency heating.

Some of these terminologies apply to the use of different, specific frequency ranges of the electromagnetic spectrum, e.g., radio waves or microwaves.

Principle of Operation for Dielectric Heating

Multiple heat-generating mechanisms can be involved, depending on the frequency range of the electromagnetic radiation involved. The basic (most common) mechanism is heat generation via molecular rotation.

Molecular rotation occurs in materials containing polar molecules (which have an electrical dipole moment), such as water. These molecules will align themselves in an electromagnetic field. If the electromagnetic field is oscillating, as it is in an electromagnetic wave, these molecules rotate continuously to align with it. (This is called dipole rotation.) As the field alternates, the molecules reverse direction. Rotating molecules collide, pull each other, or pull other molecules, distributing their energy to adjacent molecules in the material. The distributed kinetic energy appears as heat.

Dipole rotation is one mechanism by which energy in the form of electromagnetic radiation can raise the temperature of an object. This effect can be used to heat gases, liquids and solids, as long as these materials have some polar molecules. In liquids with dissolved salts an additional effect called "ion drag" can cause heat generation; as charged ions are moved back and forth they transfer kinetic energy to other liquid molecules as they are hit, pushed, or pulled.

With respect to bitumen production from oil sands, the electromagnetic field is generated from one or more antennae that is inserted into the bitumen field.

The key effect of the heat generation is to reduce the viscosity of the bitumen. This improves the mobility of the bitumen and makes it easier to pump it to the surface. The existing or added water or added hydrocarbon solvent also helps to transfer heat throughout the matrix.

Historical R&D

IITRI (Illinois Institute of Technology Research Institute) conduced R&D on RF-based oil shale oil and oil sands bitumen recovery processes in the 1980s.

Firms Currently Developing Dielectric Heating Technology

The ESEIEH (pronounced "easy") consortium currently is developing a bitumen production process that is based on dielectric heating.

Perceived Benefits of Dielectric Heating Method

- No need for natural gas and steam generation
- Much lower on-site GHG emissions
- Very little, if any, net added water is required
- Allows bitumen extraction in areas too deep for mining and too shallow for SAGD

- Achieves volumetric heating (per claims)[28]

Potential Problems with Method

- Increased Offsite GHG emissions (related to electricity production from coal and natural gas)
- Solvent (and by-products from solvent breakdown) migration into groundwater (if solvent is added as transport/heat transfer facilitator)
- Risk for solvent loss to the formation—function of geology and reservoir characteristics
- Sand—could be surface disposal problem if sand production per barrel of oil is too high

7.1.3 Induction Heating

Principle of Operation for Induction Heating

Induction-based processes use alternating electrical current flowing through a set of conductors to induce an electro-magnetic field. The variation of the magnetic field generates heat in a material that is affected by the magnetic field.

A basic induction heating set-up is shown below in Figures 7.1 and 7.2.[29] As shown in Figure 7.1, a radio-frequency type power supply sends an AC current through an inductor (often a copper coil), and the device ("part') to be heated is placed inside the inductor. The inductor serves as the transformer primary and the part to be heated becomes a short circuit secondary. When a metal part is placed within the inductor and enters the magnetic field, circulating eddy currents[30] are induced within the part.

As shown in Figure 7.2, these eddy currents flow against the electrical resistivity of the metal, generating precise and localized heat. This is accomplished without direct contact between the part and the inductor. This heating occurs with both magnetic and non-magnetic parts, and is

[28] The claim of volumetric heating may deserve further analysis, beyond the scope of this screening study. Some of Jacobs Consultancy's electrical engineers have concerns about the extended and even transmission of RF waves through typical oil sands material.
[29] Diagram from Ind*uctive Logic Limited*
[30] Eddy currents are electric currents induced in electrical conductors when the conductor is exposed to a charging magnetic field. This causes a circulating flow of electrons within the body of the conductor. These circulating eddies of current have inductance and thus induce magnetic fields. Eddy currents, like all electric currents, generate heat as well as electromagnetic forces. The heat can be used for induction heating. Eddy currents also are called Foucault currents

often referred to as the "Joule effect," referring to Joule's first law, which describes the relationship between the heat generated by the current flowing through a conductor.

Induction heating is a process that is used to bond, harden or soften metals or other conductive materials. For many modern manufacturing processes, induction heating offers an attractive combination of speed, consistency and control.

The basic principles of induction heating have been understood and applied to manufacturing since the 1920s. During World War II, the technology developed rapidly to meet urgent wartime requirements for a fast, reliable process to harden metal engine parts. More recently, the focus on lean manufacturing techniques and emphasis on improved quality control have led to a rediscovery of induction technology, along with the development of precisely controlled, all-solid-state induction power supplies.

What makes this heating method so unique is that in the most common heating methods, a torch or open flame is directly applied to the metal part, whereas with induction heating, heat is actually "induced" within the part itself by circulating electrical currents.

Induction heating relies on the unique characteristics of radio frequency (RF) energy, that portion of the electromagnetic spectrum below infrared and microwave energy. Since heat is transferred to the product via electromagnetic waves, the part never comes into direct contact with any flame, the inductor itself does not get hot, and there is no product contamination. When properly set up, the process becomes very repeatable and controllable.

Physics of Induction Heating

When an alternating electrical current is applied to the primary of a transformer, an alternating magnetic field is created. According to Faraday's Law, if the secondary of the transformer is located within the magnetic field, an electric current will be induced.

In the basic induction heating setup, a solid state RF power supply sends an AC current through an inductor (often a copper coil), and the part to be heated is placed inside the inductor. The inductor serves as the transformer primary and the part to be heated becomes a short circuit secondary. When a metal part is placed within the inductor and enters the magnetic field, circulating eddy currents are induced within the part.

Figure 7.1
Basic Induction Heating Equipment Set-up

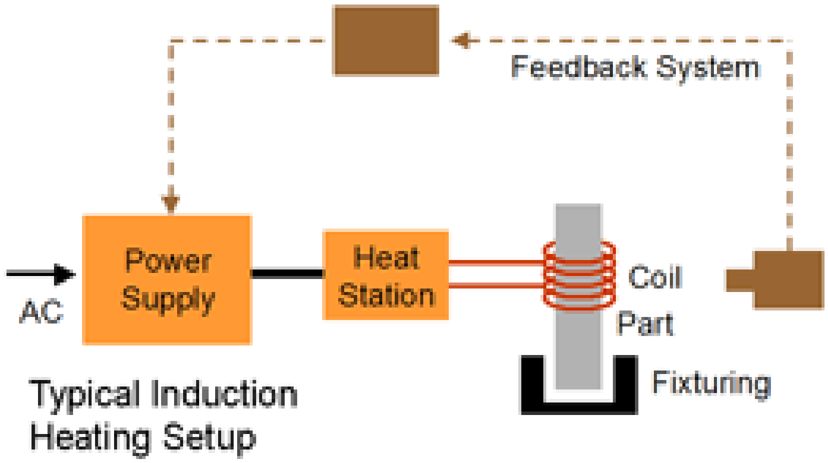
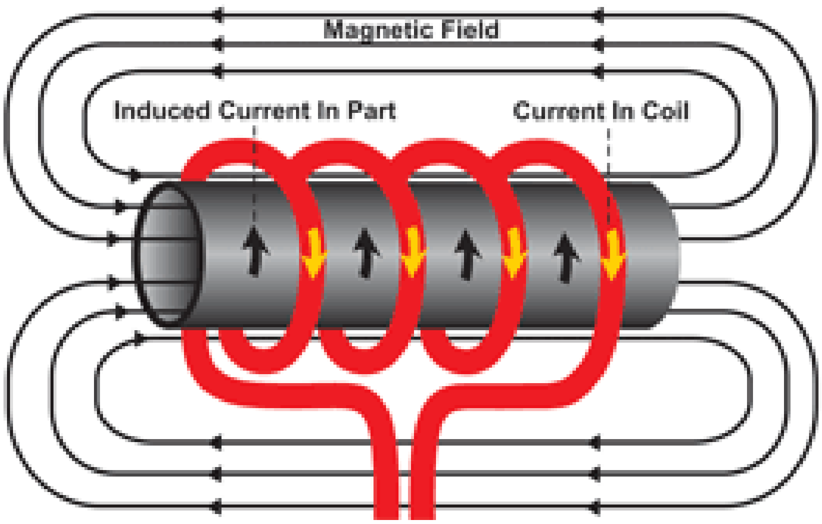


Figure 7.2
Eddy Currents and Magnetic Field Created via Induction



As shown in Figure 7.2, these eddy currents flow against the electrical resistivity of the metal, generating precise and localized heat without any direct contact between the part and the inductor. Additional heat is produced within magnetic parts through hysteresis, internal friction that is created when magnetic parts pass through the inductor. Magnetic materials naturally offer electrical resistance to the rapidly changing magnetic fields within the inductor. This resistance produces internal friction that in turn produces heat.

The part to be heated can be placed in the ground, can extend beyond the induction coils, or can be submerged in a liquid.

In most induction systems conceived or developed for bitumen production, alternating electric current is conducted through the coils of an inductor which generates a magnetic flux necessary to induce current in the steel walls of the well's production casing or liner, thereby producing heat by a combination of ohmic and hysteresis losses in the liner material. Heat is conducted from the casing and liner into the production zone. Either three-phase or single-phase power can be used to supply the power inductor assembly.

Historical R&D

There are records of R&D work on oil production using this technique as far back as 1997 (CNRL), 1998 (Bahrain Petroleum Company) and 2001 (Renaissance Energy Company). A Calgary firm called Madis Engineering Ltd. has been selling down-hole induction heating systems for heavy oil viscosity reduction since (at least) the mid 1990s. They combined with Tesla Industries to offer a system for bitumen production in the late 1990s.

Firms Currently Developing or Testing Induction Heating Technology in Alberta

Siemens Energy has conducted some preliminary testing with an electromagnetic-based system in Bavaria in areas where they claim that geology and conductivity are similar to Alberta's oil sands region. In 2010, Siemens said it was talking to some Canadian heavy oil producers regarding technology demonstrating tests. Siemens believes its heaters could be added to an existing steam-assisted gravity drainage (SAGD) operation to create a hybrid process called EM-SAGD. Our public domain information gathering during this Study uncovered no additional information regarding ongoing business development or current plans to test this technology on bitumen production.

Potential Benefits of Method

- No need for natural gas and steam generation
- Much lower on-site GHG emissions (Siemens has said it expects a 20% reduction in overall energy consumption per barrel of bitumen produced.)
- Very little, if any, net added water is required
- Allows bitumen extraction in areas too deep for mining and too shallow for SAGD

Potential Problems with Method

- Increased offsite GHG emissions (related to electricity production from coal and natural gas)

- Does not achieve volumetric heating.[31]

7.2 Discussion of Promising Technologies

Based on public domain information, the two most promising technologies for electricity-based in situ bitumen production from oil sands appear to be:

- ET-Energy's DT-ESP technology
- ESEIEH technology

Shell has been promoting an electrical-based bitumen production technology called ICP, but based on information gathered to date, it is only being applied to bitumen in carbonate formations.

7.2.1 ET-Energy's DT-ESP[32] Process

Although still clearly in the R&D phase, ET-Energy's technology is well advanced in terms of commercial partnerships, funding and pilot test results. Simple schematic diagrams of the process are shown in Figures 7.3 and 7.4.[33]

Claimed Benefits

ET-Energy’s proposed technology benefits are:

- Avoids costs and environmental issues associated with steam production[34]
- Eliminates water treatment and steam production facilities, which significantly reduces up-front capital costs, making economics superior to existing commercial bitumen extraction processes
- Less water used compared to SAGD[35]
- Less GHG production compared to SAGD[36]

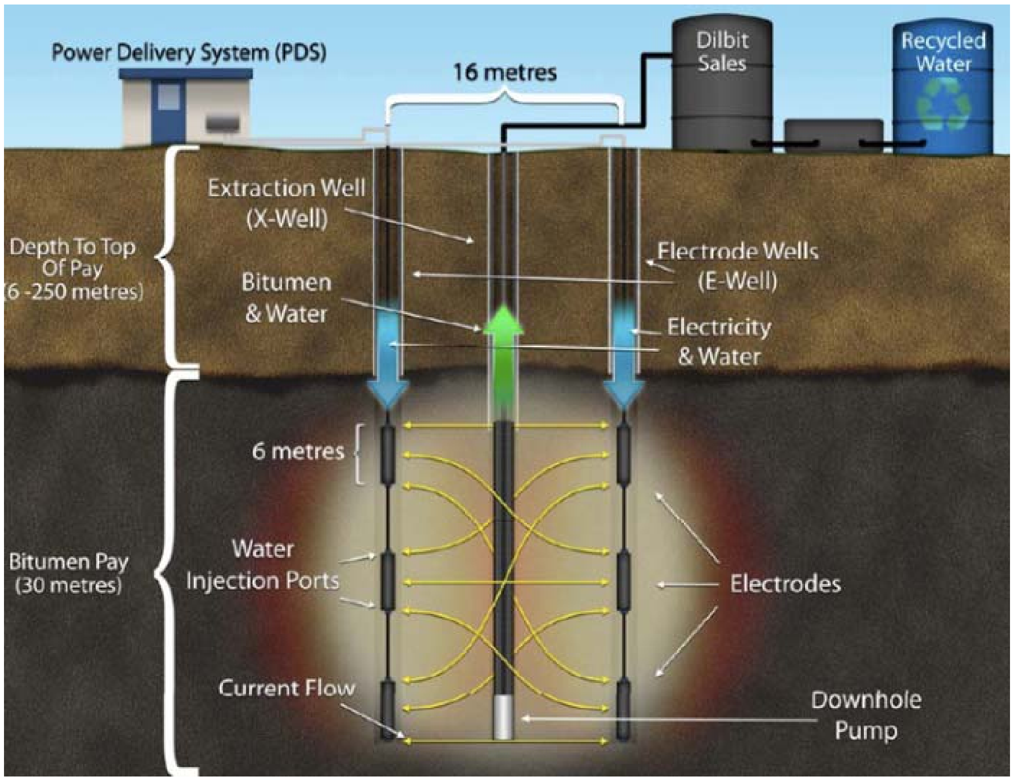
[31] Heats via conduction and convection effects generated by the heater casing
[32] ET-DSP: Electro-Thermal Dynamic Stripping Process
[33] From ET-Energy promotional materials
[34] This claim, by ET-Energy ignores the emissions produced by traditional electricity production from a combination of coal and natural gas.
[35] Although this comparison can be used as a point of reference, comparison to SAGD is actually an apples to oranges comparison, as these technologies target different regions of the bitumen-containing formations

- Provides the opportunity to unlock bitumen volumes at depths in the range of 50 meters to 150 meters, currently inaccessible via current extraction methods (too deep for mining and too shallow for SAGD

[36] This claim, by ET-Energy ignores the emissions produced by traditional electricity production from a combination of coal and natural gas.

Figure 7.3

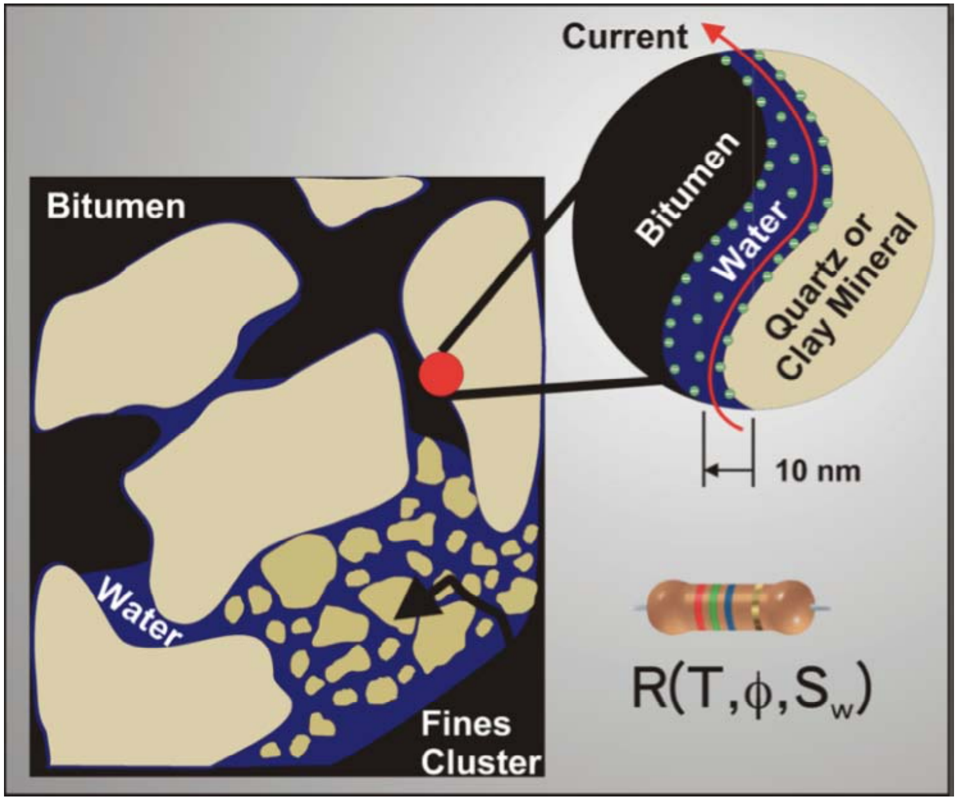
ET-DSP™ Process



- **Power Delivery System distributes electrical current and non-potable water to the electrode wells.**
- **Electric current energizes the electrodes, while injected water cools the electrodes.**
- **Electric current rapidly cycles between electrodes, heating the formation water and bitumen.**
- **Injected water maintains electrical conductivity and formation pressure.**
- **Heated bitumen and water are pumped from the formation by progressive cavity pumps.**
- **Bitumen is cleaned to sales spec and sold into markets.**
- **Produced water is recycled and re-injected to minimize the need for external water.**

Figure 7.4

ET-DSP™ Process



- Oil sands formations are highly permeable and contain a significant amount of in situ formation water
- Electrical current is conducted through the formation water that envelops the non-conductive sand particles
- Water is strongly resistant to electricity and the electrical energy is converted to heat, i.e. the water gets hotter the more current that flows
- The water is heated to +/-\130 deg. C, but the formation pressure prevents it from flashing into steam
- Heat is transferred from the water to the oil and sand particles by conduction
- The large surface area between the water film and the sand particles facilitates the rapid transfer of heat.

In 2007, ET-Energy completed a field test, called the POC ("Proof of Concept") test, in the Athabasca region, using closely spaced electrodes in an oil sands formation. Electrodes and production wells were placed in boreholes. Water was injected continuously into the electrodes to transfer heat rapidly into the oil sands. The heated bitumen-water-solids mixture then was extracted at production wells using surface pumps; 2,200 bbl of bitumen were recovered and sent to market.

ET-Energy now is entering into a large-scale development phase. Corporate and permit approval for a first commercial project was expected in February 2010 and, per promotional materials, first oil is expected in 2014.[37] They have recently received more equity investment and have entered into a JV Agreement with TOTAL to help fund their latest field pilot test.[38]

According to ET-Energy, the second field pilot is planned to incorporate longer distances between electrodes which will further optimize the process and test commercial feasibility. This second pilot is underway now and is targeted to produce ~90,000 bbl at a rate of 275 to 325 bpd. First oil is expected in May 2012.

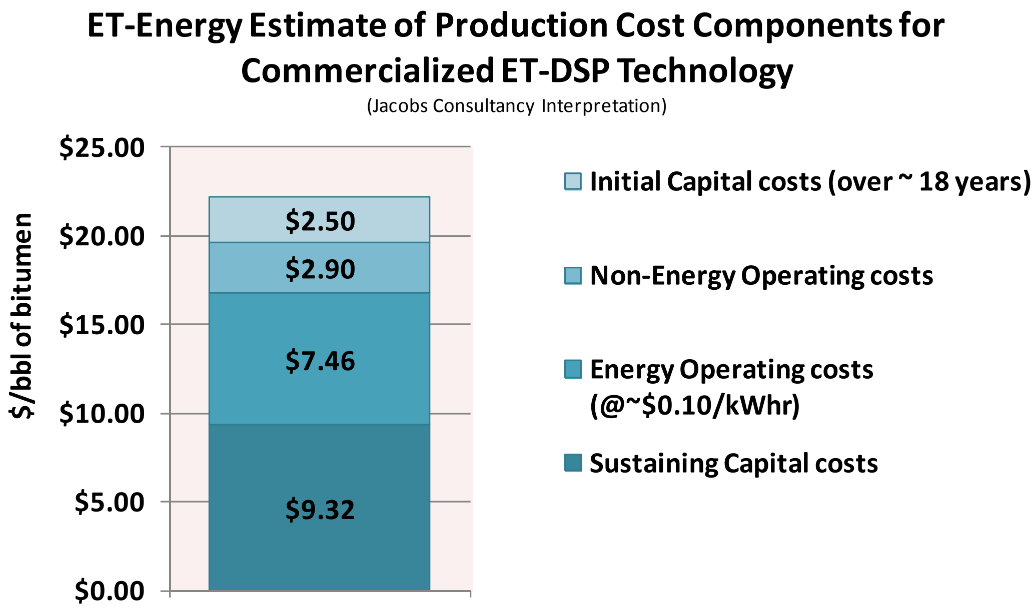
In a recent public-domain investor presentation ET-Energy presented its estimate of fully loaded production costs for the ET-DSP. Our interpretation of this estimate is shown below as Figure 7.5. Two key values emerge:

- They estimate that total operating costs are <$11/bbl
- They estimate that fully loaded costs are <$22.50 over an 18-year project (production site) lifetime

In this most recent investor presentation ET-Energy notes that an independent engineering/consulting firm reviewed ET-Energy's commercial Opex and CAPEX projections and predicted an energy use/bbl recovered ratio 30% higher than the ET-Energy estimates and a capital cost estimate 55% higher. ET-Energy's response to this independent analysis was that they believe their assumptions will be proven by the results of the latest field test. The engineering/consulting firm indicated they will review their assumptions subsequent to the completion of the current test.

[37] One interpretation of ET-Energy's latest investor presentation is that they are focusing on becoming a production firm versus a technology licensing firm. They say are targeting an IPO in mid-2012.
[38] As part of their agreement with TOTAL, TOTAL has gained an option for non-exclusive licensing rights to the ET-DSP technology and a 30% interest in the initial (planned) 10,000 bpd production project.

Figure 7.5



Comments of the Results from ET-Energy's 2007 POC (Proof of Concept) Field Test

We have many questions regarding the ET-Energy POC field test results and the associated estimates of commercial capital and operating costs that were based, in part, on the pilot test data. The information that is available in the public-domain indicates:

- An average energy use to produced oil ratio of 62 kWhr/bbl was observed.
- Net water use was negligible. (All produced water was recycled, with minimal treatment.)
- Water injection pressure was low, "equivalent to hydrostatic pressure or less."
- "No stable emulsion was formed." "Water, oil and sand separation was via gravity settling, with some diluent added to accelerate the separation."
- ET-Energy estimates that more than 70% of available bitumen was recovered to produce 2,200 bbl of bitumen that was sold into the market, after sand and water removal.

For the POC test nine electrode wells and four production wells were drilled at a depth of ~80 meters. Not all the wells were functioning fully during the test due to electrode failures. ET-Energy says that the electrode failures were due to a "simple to fix" design flaw that will be implemented for the next filed trial.

Questions that Jacobs Consultancy has about the POC test and ET-Energy's most recent (public domain) ET-DSP Process capital and operating cost estimates

We asked ET-Energy most of the questions noted below. Despite our offer to execute a non-disclosure agreement, they declined to provide any information beyond what was available in the public domain. We assume that in their due diligence activities, TOTAL will pursue similar issues:

- ET-Energy says that, "Surface facilities can be limited to just oil-water separation processes." What about H_2S treatment? How do you plan to handle H_2S in produced gas?
- How much produced gas did you generate during your POC test?
- How exactly did you treat your recycled water in your 2006-2007 POC test?
- How much diluent was added to "accelerate" the water-sand-bitumen separation process?
- Can you describe the technique and apparatus used to effect separation?
- Exactly what type of diluent was used?
- What was the bitumen residence time for the separation system?
- We wonder about water treating for a longer-term operation. In a longer-term operation what are your expectations regarding recycled water quality and the need for treatment?
- In your POC test, how did contaminate levels in the water change as water was continually recycled (TDS, salinity, other)?
- In the February 12 presentation to the Canadian Prairies Group of Engineers, ET-Energy notes that the capital costs for E-Wells and X-Wells are assumed to be $47,395 and $49,277 respectively. Are these total installed costs on a 2012 basis?
- Do these costs assume any re-use of equipment or material? How much are these costs a function of well depth?
- Are post-production site remediation costs included in your project cost estimate?
- Can you break out the components of your sustaining capital cost estimates?

7.2.2 ESEIEH Technology Process

The ESEIEH (Enhanced Solvent Extraction Incorporating Electromagnetic Heating) technology (pronounced "easy") currently is at the R&D stage of development. The R&D is being conducted by a four-member consortium that was announced in July 2010:

- Laricina Energy Ltd.
- Nexen Inc.
- Suncor Energy Inc.
- Harris Corporation of Melbourne, Florida

In 2010, the consortium received $16.5 million in funding from the Climate Change and Emissions Management Corporation (CCEMC), to be applied toward a four-year field demonstration pilot (the "Project"). As of January 2012, CCEMC reports that the project is 20% complete.

According to recent press releases, the Project incorporates staged yard-scale testing, numerical modeling studies and a small-scale field trial. The Project is expected to run for four years and consists of two phases. Phase 1 of the Project includes a technical feasibility study and a surface mine face test with total funding of about $6 million. Phase 1 was targeted to begin in September and run for one year. Phase 2 consists of an in situ field pilot test that uses a 200-metre horizontal well with a total funding of an additional $27 million. The funding beyond the $16.5 million CCEMC grant is to be provided by the partners in proportion to their respective percentage ownership.

ESEIEH Technology Description

According to public domain information released by the consortium, ESEIEH is a new in situ oil sands recovery process that does not use steam in heating the reservoir. In this process bitumen is concurrently heated with electromagnetic energy (radio waves) and further diluted with the injection of a solvent in a gravity drainage recovery process. ESEIEH claims that its technology provides the advantages of lower overall energy requirements and may mitigate the need for field site burning of natural gas or fossil fuels to produce steam, thereby lowering direct emissions.

The diluting solvent is expected to reduce bitumen viscosity and facilitate transfer of the warmed, reduced viscosity bitumen to the surface. The electromagnetic heating is generated via an antenna that is inserted in the bitumen formation. An antenna distributes electrical power in the form of an electromagnetic field that heats the bitumen. No steam or water are added during the operation. We have found no reliable sources that identify the solvent that will be used.

According to public domain information, ESEIEH operates with two horizontal well pairs as in a base SAGD configuration, with the addition of an antenna close to the well pairs. The antenna distributes electrical power, in the form of an electromagnetic field, which heats the bitumen and allows it to be drained. A solvent is then injected in a manner that "achieves the best balance between the combined effects of heating and dilution."

It is assumed that the ESEIEH project will leverage Harris Corporation's knowledge regarding effective electromagnetic heating methods and innovative antenna designs while using existing drilling and well completion practices.

In its press releases the consortium claims that ESEIEH has the potential to:

- Be more energy efficient than current in situ processes using steam. ESEIEH is expected to result in a potential 40% reduction in energy requirements during extraction with commensurate reduction in greenhouse gas emissions.
- Significantly reduce greenhouse gas emissions. The greater energy efficiency without the field site burning of natural gas to produce steam produces lower emissions.
- Improve bitumen recovery
- Increase the amount of Alberta's recoverable reserves. The technology also can be applied to bitumen deposits currently deemed "inaccessible" (i.e., located at depths deemed too deep for mining and too shallow for in situ steaming). The technology can be applied to both classic as well as carbonate formations thereby offering potential for reserve growth.
- Reduce water use. There are potential cases that require no source water, water processing, steam generation, or water re-cycling requirements. The process will be net water positive where steam in not used.
- Help with sequestration. Emissions from power generation can be more easily captured at a central facility for sequestration, providing better carbon management.
- Perform upgrading. There is potential for in situ chemical upgrading along with fluid upgrading.
- Help lower the cost structure for bitumen recovery. ESEIEH displaces steam in the in situ recovery process, thereby reducing the operating and capital cost requirements for water sourcing and handling facilities. Furthermore, ESEIEH is expected to provide greater bitumen recovery at a lower overall energy cost

No public domain cost or yield information is available for the ESEIEH process.

The ESEIEH Consortium

The fundamental technology for ESEIEH, electromagnetic heating, originates with Harris Corporation. Laricina, Nexen and Suncor are expected to provide experience and knowledge related to reservoir management, SAGD well applications, solvent-use expertise and field execution-expertise. The press releases for the joint venture say that "the strength and collaboration of the four partners will ensure a well-managed process for both the fundamental and applied research aspects of the project. The research will be conducted to understand both the physics of electromagnetic heating combined with solvent-based extraction in bitumen-saturated reservoirs."

The partnership is described as multi-dimensional, where participants provide specialized expertise and contributions. Each of the industry partners contributes approximately 21% while Harris contributes 37 percent.

Per the initial Press Release the backgrounds of the companies involved are:

> **Harris Corporation** is an S&P 500 company with over $5.0 billion in sales (FY 2009) that specializes in the design and support of high-power, high-reliability, mission-critical networks and radar systems. Harris has served agencies and departments of the US government for more than 50 years. The company has:
>
> - Over 15,000 Harris employees worldwide
> - 6,500 engineers and scientists
> - 2,300 advanced degrees including over 130 PhDs
> - Global presence 150 countries, including Canada
>
> Harris Corp. says it has more than 50 years of electromagnetic technology development experience.
>
> **Laricina** is a privately held, Calgary-based company concentrating on capturing opportunities in the oil sands areas of Western Canada. The Company is creating value through developing a diverse portfolio of oil sands assets using current and future innovations of in situ technology. Laricina has identified five core areas that present production potential in excess of 500,000 gross barrels of bitumen per day from a large concentrated resource base with approximately 4.6 billion barrels net recoverable

bitumen. These assets range from the familiar oil sands in the McMurray formation to less developed and less mature Grand Rapids and Grosmont and Winterburn carbonate plays, all of which offer significant resource potential.

Nexen Inc. is an independent, Canadian-based global energy company, listed on the Toronto and New York stock exchanges under the symbol NXY. The company pursues three growth strategies: oil sands and unconventional gas in Western Canada and conventional exploration and development primarily in the North Sea, offshore West Africa and deep-water Gulf of Mexico. Nexen is committed to successful full-cycle oil and gas exploration and development, leadership in ethics, integrity, governance and environmental stewardship

Suncor Energy Inc. is an integrated energy company focused on developing Canada's Athabasca oil sands. Suncor's operations include oil sands development and upgrading, conventional and offshore oil and gas production, petroleum refining, and product marketing under the Petro-Canada brand. While working to responsibly develop petroleum resources, Suncor is also developing a growing renewable energy portfolio. Suncor's common shares (symbol: SU) are listed on the Toronto and New York stock exchanges.

Additional information on ESEIEH Consortium and Project Plans

With respect to rights, management, expectations, timing and costs, the following was revealed in an initial press release:

How will the project be managed?
The project will be managed under the purview of a management committee with equal voting rights among the four participating industry partners.

Where will technology be tested?
The technology will be tested within a McMurray oil sands reservoir environment in two phases, a surface field test to validate the electromagnetic heating technology and an in situ pilot test where electromagnetic heating will be accompanied by solvent injection.

Who will operate the project?
Details of the project operation in each phase are currently being finalized.

What rights will the partners have to the technology?

The petroleum industry partners, Laricina, Nexen and Suncor, will receive a price advantage and preferential access to equipment on commercialization. Harris will own and commercialize the technology.

What are the project objectives?

The project objectives are to provide a proof of concept of the ESEIEH process with a field demonstration pilot of the technology. Proven aspects of the technology will be commercialized as developed either in parallel with the project execution, or following completion.

What are the expected phases and costs of the project?

Phase 1 will consist of a technical feasibility study and will include a surface mine face test with a total funding of approximately \$6.0 million. The target start date of Phase 1 is September 2010 and will run for one year. Phase 2 will consist of an in situ field pilot test with a total funding of an additional \$27.0 million.

When will the project start?

The project is expected to formally start in September 2010, with a review of Phase 1 results by the end of 2011. Phase 2 would begin immediately following Phase 1, with a final review of the test results expected by the end of 2014.

What will the project cost?

The current project plan identifies a \$33 million project budget for the ESEIEH pilot. The cost of Phase 1 is estimated at \$6 million while Phase 2 is \$27 million.

How long will it need to operate before results can be obtained?

The project is expected to run for four years through several phases. Successful results at each phase may lead to commercialization of emerging products over the life of the project.

If successful, how long before the technology becomes commercial?

A number of milestones over the course of the project may lead to commercial products as the project proceeds. However, the commercial deployment of the full ESEIEH process will likely follow completion of the project.

What reporting will be required during the operation of the project?

Contractual agreements are entered into with proponents of approved projects and proponents are responsible for regularly reporting on performance. Information about funded projects and project status information will be made available through a variety of mediums, including the Climate Change and Emissions Management Corporation (CCEMC) annual report, newsletter and website.

Is there a patent on the technology?
A wide range of patents specific to the ESEIEH process are currently held or pending.

7.3 Conclusions

It appears that both the ET-Energy ET-DSP process and the ESEIEH process may have significant potential, especially if low-priced electricity becomes available, or if natural gas prices start trending higher in the future.[39] Both technologies are worthy of some degree of further evaluation, most likely after initial in-field results are available for analysis.

Both technologies also offer the promise of monetization of bitumen reserves that cannot be accessed by either traditional; SAGD or mining technology. This, by itself, makes both technologies attractive in terms of maximizing corporate return on reserve assets.

ET-Energy: The ET-Energy POC (Proof of Concept) test results are significant. Using ET-Energy assumptions, we estimate a production cost of ~$22.50/bbl ($2010) based on their POC run results.[40] The fact that TOTAL has partnered with ET-Energy adds some degree of credibility to the potential of this technology.

ESEIEH: Despite the lack of any public domain test run data, the logical claim of more volumetric heating[41] than the ET-DSP type process, the initial positive results from the ET-DSP POC run, and the fact that Suncor and Nexen have joined the ESEIEH consortium indicate a reasonable level of promise.

[39] The availability of nuclear generated electricity would make these technologies even more interesting.
[40] This is an estimate based on ET-Energy's public domain data, and made without a full understanding of the validity of many of their assumptions used for cost component estimates. We expect there is a good chance that an equilibrium production cost could be higher than this value.
[41] Volumetric heating occurs due to the exposure of the entire surrounding formation to an electromagnetic radiation, with the effects of exposure diminishing with distance from the source. This is in comparison to resistance heating, where the heat generation occurs only at the route of current flow.

8.0 Abbreviations Used in this Report

Terminology used in this report is summarized below:

BD	Blowdown
BFD	Block flow diagram
BFW	Boiler feed water
CAPEX	Capital expenditure
CPF	Central processing facility
CWE	Cold water equivalent
DHT	Diesel Hydrotreater
DRU	Diluent recovery unit
DSI	direct steam injection
EMGD	electromagnetic gravity draining
EPCM	Engineering, procurement, construction and management
ERCB	Energy Resources Conservation Board
ESEIEH	Effective solvent extraction incorporating electromagnetic heating
ESP	Electric submersible pump
ET-DSP	Electro-thermal dynamic heating process
FCSG	Forced-circulation steam generator
FWKO	Free Water Knockout
GOR	Gas to Oil Ratio
HP	high pressure
HRSG	heat-recovery steam generator
ICP	in-situ conversion process

kPag	kilopascals Gauge
KBPSD	thousand barrels per stream day
MHC	Mild Hydrocracker
MVC	mechanical vapor compression
MT	metric tonnes
MTBF	mean time between failures
NHT	Naphtha Hydrotreater
NOX	nitrous oxides
OPEX	Operating expenditure
ORF	Oil removal filter
OSBL	Outside battery limits
OTSG	Once-through steam generator
PW	Produced water
RF	Radio frequency
SAGD	Steam-assisted gravity drainage
SCO	Synthetic crude oil
SOR	Steam-oil ratio
SOX	Sulfur oxides
SRU	Sulphur Recovery Unit
TBP	True boiling point
TDS	Total dissolved solids
TIC	Total installed cost
VDU	Vacuum Distillation Unit
WAC	Weak acid cation

WLS	Warm lime softening
ZLD	Zero liquid discharge

Appendices

Appendix 1: SAGD Case Capital Cost Details

Table 1 is a summary of the estimated total installed capital costs developed for each case. The differences in capital costs for each new technology case, versus the base case, are discussed below.

All costs are order of magnitude curve costs (+/- 50%) with adjustments based on both in-house and vendor supplied equipment cost data.

SAGD-1 Case: CPF Electric Boiler

- Well-pad, gathering line, separation, and de-oiling facilities are unchanged, as there will be no change in emulsion or produced water flow.

- Water treating facility costs are changed to reflect using MVC evaporators in place of WLS in order to provide the required water quality for electric boilers. New costs are estimated using internal curve costs.

- Electric boilers are specified to replace OTSG's. The costs were estimated from a quote provided by Chromalox. 20 electric boilers (at 4MW each) will be used to replace each OTSG. The vendor quote used for this estimate is adjusted with installation and labor factors consistent with Jacobs Consultancy's cost curve data.

- Utility and offsite costs are increased to reflect estimates of increased piping requirements as well as power lines and substations required for the increased power requirements.

- CPF indirects, EPCM, owner costs and contingency are all increased in proportion to the direct cost increases for well-pads, gathering lines, and the CPF.

Overall this case reflects a capital cost increase of more than $60 million (+3%) compared to the base case. For this technology, there are limited data for equipment at the scale required. Our equipment cost estimates reflect conservative assumptions on scaling (e.g., we are assuming several small boilers as opposed to a single large boiler). Further study with increased vendor involvement might result in a reduced cost estimate.

Table 1
Detailed Capital Costs for SAGD Base Case and SAGD Technology Cases

		PTAC Base Case	SAGD-1	SAGD-1A	SAGD-2	SAGD-3	SAGD-4	SAGD-5	SAGD-6	SAGD-7
		Base Case 40 kbpcd	CPF Electric Boilers	CPF Steam Compressor	Boilers at Well Pads	Compressors at Well Pad	Electric Steam Superheat	RO Raw Water Treatment	MVC Evaps	ZLD
Diluent	BPSD	13,330	13,330	13,330	13,330	13,330	13,330	13,330	13,330	13,330
Bitumen	BPSD	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Natural Gas	GJ/hr	2,014	201	1,108	1,914	1,934	1,914	1,994	1,994	1,994
Power	MW	26.7	450.4	238.6	50.6	51.2	50.6	27.7	43.2	49.7
CAPEX										
Drilling & Completions (Inc. ESP's)	$ Mil	$242	$242	$242	$242	$242	$242	$242	$242	$242
Well Pads & Gathering Lines	$ Mil	$210	$210	$210	$210	$235	$209	$210	$210	$210
Separation and De-Oiling	$ Mil	$104	$104	$92	$102	$103	$102	$104	$104	$104
Water Treating	$ Mil	$85	$131	$59	$82	$82	$82	$90	$131	$167
Steam Generation	$ Mil	$120	$78	$185	$115	$116	$115	$120	$65	$66
Offsites and Utilities	$ Mil	$313	$331	$331	$313	$314	$313	$314	$306	$327
CPF Indirects	$ Mil	$224	$239	$239	$219	$220	$219	$225	$227	$254
EPCM & Owners Costs	$ Mil	$322	$335	$325	$317	$323	$317	$324	$320	$344
Contingency (25%)	$ Mil	$345	$357	$360	$339	$348	$339	$347	$341	$293
Total Facility Capital Costs	**$ Mil**	**$1,965**	**$2,027**	**$2,043**	**$1,939**	**$1,983**	**$1,938**	**$1,976**	**$1,946**	**$2,007**
Delta Capital Cost	**$ Mil**		**$62**	**$78**	**($26)**	**$18**	**($27)**	**$11**	**($19)**	**$42**

SAGD-1A Case: CPF Steam Compressor

- De-oiling and water treating costs are reduced, reflecting flashing of produced water to provide steam vapor for compression.

- Steam generation is assumed to be split between OTSG's and steam compressors. The steam compressor cost is determined by a curve cost for a screw-type compressor. One may be able to reduce compressor costs if more information on the required compression ratio, vapor composition and reliability is developed, but using a screw-type compressor is an adequate starting point.

- Costs for offsites and utilities are increased in line with increases in steam generation and to reflect increased electric import facilities.

- CPF indirects, EPCM, owner costs and contingency are all increased to be in proportion to the direct cost increases for well-pads, gathering lines, and the CPF.

Overall this case reflects a capital cost increase of almost $78 Million, which is a 4% increase over base case costs. For this technology, there are limited data for equipment at the scale required. Our equipment cost estimates reflect conservative assumptions about scaling (e.g. we assume several small boilers as opposed to a single large boiler). Further study with increased vendor involvement might result in a reduced cost estimate.

SAGD-2 Case: Well-pad Electric Boilers

- Gathering line and well-pad costs reflect the cost for well-pad boilers, offset by a reduction in gathering line sizes (due to reduced condensate recycle).

- CPF facilities are all reduced in cost to reflect a 5% reduction in condensate recycle through the emulsion handling, water treating and steam generation systems.

- Offsite costs are roughly the same as those in the base case, due to the approximate equivalence of the decrease in CPF infrastructure costs to the increase in electric facilities for well-pads.

- CPF indirects, EPCM, owner costs and contingency are all decreased in proportion to the direct cost reductions for well-pads, gathering lines, and the CPF.

The total capital costs for this case are $26 Million (~1%) less than the base case.

SAGD-3 Case: Well-pad Electric Compressors

- Gathering line and well-pad costs are increased, reflecting the cost for well-pad compressors offset by a reduction in gathering line sizes (due to reduced condensate recycle).The compressor cost is based on a screw compressor, for reliability reasons. A different compressor selection could reduce this capital cost, although there is a good chance this would reduce system reliability.

- CPF facilities are all reduced in cost to reflect a 5% reduction in condensate recycle through the emulsion handling, water treating and steam generation systems.

- Offsite costs are roughly the same as the base case. This is due to the approximate equivalence of the decrease in CPF infrastructure with the increase in electric facilities for well-pads.

- CPF indirects, EPCM, owner costs and contingency are all increased in ratio to the direct cost increases for well-pads, gathering lines, and the CPF.

The total capital costs for this case are $18 Million (~1%) higher than the base case.

SAGD-4 Case: Electric Steam Superheaters

- Gathering line and well-pad costs are slightly less, reflecting the cost for electric superheaters offset by a reduction in gathering line sizes (due to reduced condensate recycle), Superheaters are less expensive than the corresponding boilers because they will require less auxiliary equipment (BFW pumps, chemicals, separation drum etc.)

- CPF facilities are all reduced in cost to reflect a 5% reduction in condensate recycle through the emulsion handling, water treating and steam generation systems.

- Offsite costs are roughly the same as the base case. This is due to an approximate equivalency of the decrease in CPF infrastructure to the increase in electric facilities for well-pads.

- CPF indirects, EPCM, owner costs and contingency are all decreased in ratio to the direct cost increases for well-pads, gathering lines, and the CPF.

The total capital costs for this case are $27 Million (1.4%) less than the base case.

SAGD-5 Case: RO Treatment for Raw Water

- Well-pads, gathering lines, separation facilities, and OTSG costs are not changed as there will be no impact on production rates or steam requirements. The small reduction in OTSG duty will not impact costs, which are more dependent on steam rate.
- Water treating costs are larger because of the additional facility that overshadows the reduction in the size of WLS.
- Utility systems were unchanged from the base case.
- CPF indirects, EPCM, owner costs and contingency are all increased in ratio to the direct cost increases for well-pads, gathering lines, and the CPF.

Capital costs for this case are $11 Million or 1% higher than those from the base case.

SAGD-6 Case: Produced Water MVC Evaporators

- Well-pads, gathering lines, and separation facilities are not changed, as there will be no impact on production rates.
- We increase water treating costs to reflect replacing WLS with MVC evaporators. We use curve costs from our internal database, adjusted on the basis of recent vendor quotes.
- Steam systems costs are decreased due to the ability to use forced circulation drum boilers in place of OTSG's. We derive our curve costs from vendor quotes from a recent project.
- Utility systems are unchanged from the base case.
- EPCM, owner costs and contingency are all decreased in proportion to the direct cost increases for well-pads, gathering lines, and the CPF.

Capital costs for this case are $19 Million (1%) less than the base case.

SAGD-7 Case: ZLD

- Well-pads, gathering lines, and separation facilities are not changed, as there will be no impact on production rates.

- Water treating costs increase because we replace WLS with MVC evaporators. Additional costs for ZLD facilities include a 2nd stage evaporator, a crystallizer and a dryer. We use curve costs from our internal database, adjusted for recent vendor quotes.

- Steam systems costs decrease due to the ability to use forced circulation drum boilers in place of OTSG's. We derive our curve costs from vendor quotes for a recent project.

- Utility systems increase in line with the infrastructure and pipe rack costs for the new facilities.

- Indirects costs, EPCM, owner costs and contingency are all increased as in proportion to the direct cost increases for well-pads, gathering lines, and the CPF.

Capital costs for this case are $42 Million (2%) larger than the base case.

Summary:

Capital costs changes (versus the base case) for all the cases evaluated are relatively small because:

- Steam system and water treating costs are a relatively small percentage of the total facility costs.

- Estimated, delivered prices for added items are not extraordinarily high. (All technologies are fairly well established.)

- None of the technologies investigated radically change the overall configuration.

Appendix 2: SAGD Case Operating Cost Details

Table 1 is a summary of the total estimated operating costs developed for each case. The differences in operating costs for each new technology case, versus the base case, are discussed below.

Based on power costs of $77.20 / MW-hr, all of the cases except Case SAGD-5 (RO of Raw Water Case) have higher operating expenses than the base case. This is to be expected because electric heat costs of $77.2 / MW-hr are significantly higher than natural gas cost of $15.77/MW-hr. Even considering efficiency improvements, electric heating will require a lower power price to be competitive.

Fixed costs were calculated as a percentage of total installed capital cost estimates for each case using a factor that Jacobs Consultancy believes is reasonable, based on our knowledge regarding current facility operating costs.

Variable costs other than power and natural gas costs were based on Jacobs Consultancy's knowledge base of the costs of each specific item.

Breakeven Power Costs Calculation

At the request of PTAC Jacobs Consultancy calculated an estimated breakeven price of power for each case.

The breakeven price is defined as the price of electricity at which the base case annualized operating costs and the new technology case annualized operating costs are the same.[42] Annualized costs were estimated by adding total operating costs to 10% of total installed capital costs. Per agreement with PTAC and to keep this calculation simple, we assumed that natural gas costs did not change as power costs changed. This is a reasonable assumption if one assumes that the reduced power costs would be the result of nuclear –powered electricity generation plants. During this calculation the price of natural gas was led constant at the value of $4.38 / GJ.

[42] In other words, the annualized breakeven cost for Case 1 will be the same as the base case at a power cost of $19.9 / MW-hr, assuming that the natural gas prices do not change.

Table 1
Detailed Operating Costs for SAGD Base Case and SAGD Technology Cases

		PTAC Base Case	SAGD-1	SAGD-1A	SAGD-2	SAGD-3	SAGD-4	SAGD-5	SAGD-6	SAGD-7
		Base Case 40 kbpcd	CPF Electric Boilers	CPF Steam Compressor	Boilers at Well Pads	Compressors at Well Pad	Electric Steam Superheat	RO Raw Water Treatment	MVC Evaps	ZLD
Natural Gas	GJ/hr	2,014	201	1,108	1,914	1,934	1,914	1,994	1,994	1,994
Power	MW	26.7	450.4	238.6	50.6	51.2	50.6	27.7	43.2	49.7
Carbon Emissions - Direct	MT/D	2,536	254	1,395	2,409	2,435	2,409	2,511	2,511	2,511
OPEX										
Variable Costs (per location)										
Power @ $77.2 / MW-hr	$ Mil/Yr	$16.7	$281.7	$149.2	$31.6	$32.0	$31.6	$17.3	$27.0	$31.1
Natural Gas@ $ 4.38 / GJ	$ Mil/Yr	$71.5	$7.1	$39.3	$67.9	$68.6	$67.9	$70.8	$70.8	$70.8
Water	$ Mil/Yr	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Treatment Chemicals	$ Mil/Yr	$6.8	$6.8	$6.8	$6.5	$6.5	$6.5	$5.9	$6.8	$6.8
Oil Treatment Chemicals	$ Mil/Yr	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0
Carbon Emission Costs @ $15 / MT	$ Mil/Yr	$12.8	$1.3	$7.1	$12.2	$12.3	$12.2	$12.7	$12.7	$12.7
Land Fill Costs @ $44.1 / MT	$ Mil/Yr	$1.3	$0.0	$1.3	$1.3	$1.3	$1.3	$1.3	$0.0	$4.6
SAGD Total "Variable Costs"		**$115.1**	**$302.9**	**$209.6**	**$125.5**	**$126.7**	**$125.5**	**$113.9**	**$123.3**	**$131.9**
Fixed Costs (per location)										
Maintenance of Production Pumps	$ Mil/Yr	$12.8	$12.8	$12.8	$12.8	$12.8	$12.8	$12.8	$12.8	$12.8
Maintenance Supply	$ Mil/Yr	$58.3	$60.1	$60.6	$57.6	$58.9	$57.5	$58.6	$57.8	$61.4
Insurance and Regulatory Fees	$ Mil/Yr	$4.9	$5.0	$5.1	$4.8	$4.9	$4.8	$4.9	$4.8	$5.1
Staffing	$ Mil/Yr	$19.4	$20.0	$20.2	$19.2	$19.6	$19.2	$19.5	$19.3	$20.5
SAGD Total "Fixed Costs"	$ Mil/Yr	**$95.5**	**$98.0**	**$98.7**	**$94.4**	**$96.2**	**$94.4**	**$95.9**	**$94.7**	**$99.8**
Total Operating Costs	$ Mil/Yr	**$210.6**	**$400.9**	**$308.3**	**$219.9**	**$222.9**	**$219.8**	**$209.8**	**$218.0**	**$231.7**
Delta Operating Costs	$ Mil/Yr		**$190.4**	**$97.7**	**$9.3**	**$12.3**	**$9.3**	**($0.7)**	**$7.5**	**$21.2**
Annualized Costs (10% CAPEX + OPEX)	$ Mil/Yr	$407.1	$603.6	$512.6	$413.8	$421.2	$413.6	$407.4	$412.6	$432.4
Assumed Electricity Price for Cost Calculation		**$77.2**								
Break even Electricity Price	$/MW-hr		**$19.9**	**$15.7**	**$42.5**	**$6.0**	**$43.3**	**$31.3**	**$35.5**	**$0.0**

Case Summaries

Operating expenses for each case reflect the following adjustments versus the base case:

SAGD-1 Case: CPF Electric Boilers

- Natural gas heat is replaced with electric heat. We have assumed that one extra OTSG boiler is retained for reliability reasons (to insure availability). The change in costs reflects an improvement in efficiency for electric heat (i.e. no flue gas heat loss). Power costs are added for MVC evaporators required to maintain electric boiler water quality.

- Solid disposal from WLS is eliminated.

- Carbon emissions reflect only emissions due to flue gas emissions and other sources within the facility. Emission charges for import electricity are assumed to be in the electric price.

- Fixed costs are higher than the base, reflecting the increase in capital costs.

The breakeven cost for this technology case is $19.9/MW-hr.

SAGD-1A Case: Well-pad Steam Compressors

- Natural gas heat is replaced with electric power for compression. While power requirements are reflect increased efficiency, the heat integration characteristics of SAGD facilities limit this benefit. Thus there are limited efficiency improvements.

- Carbon emissions are reduced, though more OTSG heat is used than in the SAGD-1 case.

- Though WLS capacity is reduced by flashing produced water, chemical requirements and sludge generation will remain the same. In effect, impurities are concentrated, reducing the size of facilities but not the chemical requirements and waste generation.

- Fixed costs are higher than the base case, reflecting the increase in capital costs.

The breakeven cost of power for this case is $15.7 /MW-hr, primarily because of the higher capital and fixed costs for this case.

SAGD-2 Case: Well-pad Boilers

- Natural gas heat is replaced with electric power for the well-pad boilers, though on a much smaller scale than for CPF electric boilers case (SAGD-1 case).

- Direct carbon emissions are reduced.

- Fixed costs are reduced in ratio to reduction in capital costs.

The breakeven cost of power for this case is $42.5/MW-hr, reflecting efficiency improvements and facility cost reductions.

SAGD-3 Case: Well-Pad Compressors

- Natural gas heat is replaced with electric power for the well-pad compressors. We assume that flashing condensate for steam compression leaves about 20% of the condensate to recycle, compared to approximately 5% for electric boilers. This means natural gas requirements are higher for this case than for the SAGD-2 case.

- Direct carbon emissions are reduced.

- Fixed costs are increased from the base case reflecting the higher well-pad costs.

The breakeven cost of power for this case is $6.0/MW-hr. Relative to the SAGD-2 case, this case has higher fixed costs and less efficiency improvements resulting in a less favorable breakeven price.

SAGD-4 Case: Electric Steam Superheaters

- Natural gas heat is replaced with electric power for the superheaters. Efficiency improvements are in line with well-pad electric boilers (SAGD-2 case).

- Direct carbon emissions are reduced.

- Fixed costs are lower, consistent lower capital costs for this case.

The breakeven cost of power for this case is $43.3/MW-hr. Relative to the SAGD-2 case, this case has lower capital and fixed costs resulting in a more favorable breakeven power price.

SAGD-5 Case: RO Treatment of Raw Water

- There is a slight improvement in efficiency due to elimination of blow-down flashing for the pick heater. The increase in power requirements for this technology is small compared to other cases. Reduction in natural gas requirements is due to integration improvements and not replacing fired heat with electric heat.

- Chemical costs are less for RO relative to water softening, and this results in a net cost reduction versus the base case.

- Fixed costs are slightly higher, but less than the reduction in non-energy operating costs.

This case has a breakeven power price of $31.3/MW-hr.

SAGD-6 Case: MVC Evaporators

- We assume there is a slight increase in efficiency for drum boilers, reflecting less boiler blow-down, which reduces system heat losses. Power requirements are based on vendor data for MVC evaporators.

- We assume that the MVC evaporator is a high pH type which has a chemical cost roughly equivalent to WLS. Waste costs are eliminated.

- Fixed costs are slightly reduced in line with capital costs.

This case has a breakeven power price of $35.5/MW-hr.

SAGD-7 Case: ZLD

- As for MVC evaporators, boiler efficiency for boilers is increased. Power requirements include MVC evaporators, crystallizer and dryers.

- Fixed costs are slightly reduced, in line with capital cost changes.

Relative to MVC evaporators case (SAGD-6), ZLD increases electricity demand without similar reductions in natural gas. This impact, combined with higher fixed costs and waste disposal costs, give this case a much lower breakeven power price approaching $0/MW-hr.

Appendix 3: SAGD Case Operating Risk Issues

The Assumptions for each case are summarized below.

SAGD-1 Case: Electric CPF Boilers

- Process Complexity – Electric boilers do not increase complexity compared to WLS/OTSG
- Operator Interaction – Required operator attention to electric boilers and MVC evaporators should be in line with or less than WLS/OTSG's
- Operator Training – Some special training will be required for operators familiar with WLS/OTSG's systems.
- Maintenance Requirements – Electric boilers with MVC evaporators should require less cleaning than equivalent WLS/OTSGs.
- Reliability – Reliability for electric boilers in SAGD service will need to be proven.
- Overall – This technology does not excessively increase risk relative to the base case, provided unit reliability can be maintained.

SAGD-1A Case: CPF Steam Compressors

- Process Complexity – Flashing produced water, concentrating solids, and operating a high compression ratio compressor all increase process complexity.
- Operator Interaction – Rotating equipment requires greater operator attention. In addition, operators still must monitor WLS and OTSG units.
- Operator Training – Operator training will be required for the new compressor systems.
- Maintenance Requirements – Rotating equipment will increase. OTSG cleaning is still required (though reduced). Concentrating produced water will increase exchanger fouling.
- Reliability – Reliability for this process may improve by allowing for steam production during OTSG outages. This benefit is offset by issues with increased fouling. Application in SAGD service will need to be proven.

- Overall – This technology will significantly increase maintenance and operating requirements, creating additional operating risks relative to the base case.

SAGD-2 Case: Well-pad Electric Boilers

- Process Complexity – Well-pad process complexity will be increased.
- Operator Interaction – Operators will be required to monitor additional heating equipment at well-pads.
- Operator Training – Operator training will be required for the new electric boilers.
- Maintenance Requirements – Well-pad maintenance will increase with negligible reduction in CPF maintenance.
- Reliability – CPF reliability will not be improved. The boilers create added risk for condensate collection which could impact steam supply.
- Overall – Well-pad electric boilers will significantly increase maintenance and operating requirements, creating additional operating risks relative to the base case.

SAGD-3 Case Assumptions: Well-pad Steam Compressors

- Process Complexity – Well-pad process complexity will be increased.
- Operator Interaction – Operators will be required to monitor additional rotating equipment at well-pads.
- Operator Training – Operator training will be required for the new compressors.
- Maintenance Requirements – Rotating equipment and well-pad maintenance will increase.
- Reliability – CPF reliability will not be improved. The compressors create added risk for condensate collection which could impact steam supply.
- Overall – Well-pad steam compressors will significantly increase maintenance and operating requirements, creating additional operating risks relative to the base case

SAGD-4 Case: Steam Superheaters

- Process Complexity – Inline heaters should not increase process complexity.

- Operator Interaction – If properly instrumented, superheaters should not require significant operator action.

- Operator Training – Some operator training will be required for the superheaters.

- Maintenance Requirements – Superheaters will require maintenance, but maintenance on condensate collection systems should be reduced.

- Reliability – Steam superheaters will not impact current operation and could improve reliability by reducing condensate in steam lines.

- Overall – This technology does not excessively increase risk relative to the base case, provided unit reliability can be maintained

SAGD-5 Case: RO Raw Water Treating

- Process Complexity – This process replaces a blowdown flash/pick heater resulting in approximately the same complexity as the base case.

- Operator Interaction – Operator interaction should be roughly in line with that required for blowdown flash/pick heater.

- Operator Training – Some operator training will be required for the new treaters.

- Maintenance Requirements – RO maintenance will be offset by reduced salting in the make-up water circuit.
- Reliability – Treating make-up water should improve reliability, provided the treating reliability can be maintained.

- Overall – This technology does not excessively increase risk relative to the base case, provided unit reliability can be maintained.

SAGD-6 Case: MVC Evaporators

- Process Complexity – Replacing WLS/OTSGs with MVC Evaporators/Drum Boilers does not increase process complexity. Auxiliary chemicals, waste handling and plot space are more extensive for WLS than evaporators.

- Operator Interaction – Evaporators and drum boilers should require less operator interaction than the equivalent.

- Operator Training – Some operator training will be required for the new water treating and boiler systems.

- Maintenance Requirements – Maintenance requirements should not increase for evaporators. Rotating equipment in MVC evaporators are low head compressors, which are typically very reliable. Waste and sludge handling will be eliminated. Improved water quality should reduce boiler cleaning requirements circuit.

- Reliability – Reliability of drum boilers in SAGD systems is still being tested, but should eventually match that for OTSGs.

- Overall – MVC evaporators do not excessively increase risk relative to the base case, provided unit reliability can be maintained.

SAGD-7 Case: ZLD

- Process Complexity – Replacing WLS/OTSG's with MVC Evaporators/Drum Boilers does not increase operating equipment.

- Operator Interaction – Based on operating experience there will be extensive operator attention required for ZLD systems.
- Operator Training – Some operator training will be required for the new water treating and boiler systems.

- Maintenance Requirements – Maintenance requirements will increase relative to both the SAGD-6 case and the base case in order to deal with the new ZLD facilities. Improved water quality should reduce boiler cleaning requirements circuit. Solids handling will be significantly increased.

- Reliability – ZLD systems in SAGD services are historically unreliable and can significantly reduce CPF reliability if alternative water disposal options are not available.

- Overall – ZLD technology will significantly increase operating and maintenance requirements, creating additional operating risk relative to the base case.

Appendix 4: Upgrading Case Capital Cost Details

Table 1 is a summary of the estimated total installed capital costs developed for each case. The differences in capital costs for each new technology case, versus the base case, are discussed below.

UG-1 Case: Electrolytic Hydrogen

- Capital costs for the electrolytic hydrogen are higher based on higher costs for the hydrogen plant as well as increased offsite costs for substations and power lines. In addition, the offsite costs reflect the cost of a new boiler required to make-up the steam lost by eliminating SMR hydrogen production.

Jacobs Consultancy received an unusually wide range of cost estimates for electrolytic hydrogen installations from different vendors. The range was +/- 20%.

In addition, the currently available per-train size that technology vendors have available is small in comparison to the needs to this base-case scale of upgrader. The range of trains that would be required is between 300 and 3000 units, depending on the technology vendor. Regardless of the high capital costs, the required footprint of this installation would appear to be problematic.

UG-2 Case: Electric Reboilers

- Electric heater costs changes reflect higher costs for electric heaters, which are approximately twice the cost of equivalent steam exchangers. These costs are reflected in the Diluent Recovery Unit and Mild Hydrocracker, where these exchangers are more likely to add value. For heavier oil units such as the coker and vacuum unit, the risk of exchanger coking may prohibit installation.

- The reduction in hydrogen plant costs reflects an assumed reduction in steam generation capacity, offset by electric heat exchangers.

Table 1
Upgrading Technology Case Capital Costs Summary

Case Description	Units	Upgrader Base Case		UG 1 - Electrolytic Hydrogen	UG 2 - Electric Heaters	UG 3 - Hot Oil System	UG 4 - Heat Pump	UG 5 - Vacuum Compressor	UG 6 - Oxygen Enrichment	UG 7 - Flexicoking & Syngas
		No Gasifier	Gasifier							
Purchased										
Athabasca bitumen	BPD	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Diluent	BPD	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000
Natural Gas	GJ/hr	5,511	0	1,630	5,023	4,766	5,267	5,087	5,088	30
Pow er	MWhr	100	0	1,410	174	203	122	145	274	224
Products Generated										
Diluent	BPD	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000
30-32 API SCO	BPD	176,669	176,669	176,669	176,669	176,669	176,669	176,669	176,669	175,169
Sulfur	LT/D	1,122	1,552	1,122	1,122	1,122	1,122	1,122	1,122	1,473
Coke	ST/D	6,249	0	6,249	6,249	6,249	6,249	6,249	6,249	1,145
CAPEX										
Diluent Recovery Unit	$Can Mil	$310	$310	$310	$330	$310	$310	$310	$310	$340
Vacuum Distillation Unit	$Can Mil	$220	$220	$220	$220	$220	$220	$220	$220	$240
Coker	$Can Mil	$920	$920	$920	$920	$920	$920	$920	$920	$1,200
Naphtha Hydrotreater	$Can Mil	$50	$50	$50	$50	$50	$50	$50	$50	$50
Diesel Hydrotreater	$Can Mil	$130	$130	$130	$130	$130	$130	$130	$130	$130
Mild Hydrocracker	$Can Mil	$970	$970	$970	$1,020	$970	$1,050	$970	$970	$1,020
Hydrogen Plant	$Can Mil	$320		$710	$300	$300	$300	$300	$320	$120
Sulfur Plant	$Can Mil	$170	$200	$170	$170	$170	$170	$170	$170	$180
Air Separation Unit	$Can Mil		$2,050						$330	
Total ISBL	$Can Mil	**$3,090**	**$4,850**	**$3,480**	**$3,140**	**$3,070**	**$3,150**	**$3,070**	**$3,420**	**$3,280**
Offsites	$Can Mil	$1,870	$2,090	$1,970	$1,890	$1,970	$1,890	$1,890	$1,910	$2,440
Contigency	$Can Mil	$500	$700	$550	$510	$510	$510	$500	$540	$500
Total Installed Costs	$Can Mil	**$5,460**	**$7,640**	**$6,000**	**$5,540**	**$5,550**	**$5,550**	**$5,460**	**$5,870**	**$6,220**
Delta Costs (versus No Gasifier Base Case)	$Can Mil			**$540**	**$80**	**$90**	**$90**	**$0**	**$410**	**$760**
Delta Costs (versus Gasifier Base Case)										**($1,420)**

UG-3 Case: Hot Oil System

- For the hot oil system there are no unit capital costs increases over the base case as we are assuming that steam exchangers and natural gas heaters can be replaced with an equivalent duty hot oil exchanger without increasing cost.

- There is a 5% offsite cost increase reflecting the cost for a hot oil heater, collection and distributions systems, and instrumentation.

UG-4 Case: Heat Pump Case

- Compared to Case UG-2, the heat pump case was limited to the mild hydrocracker as this is the unit with the most potential opportunities for implementing a heat pump design.

- Costs for implementing this option are higher on a per Btu basis as compressor costs and ancillary equipment will be significantly more costly than equivalent electric heater costs.

UG-5 Case: Vacuum Compressor

- Capital costs are approximately equivalent to the base case. Previous studies at Jacobs Consultancy have shown that ejector systems and liquid ring compressor systems are competitive on capital costs.

- Reductions in hydrogen plant costs (lower steam production) are offset by higher offsite costs for increased power demand.

UG-6 Case: Oxygen Enrichment

- The oxygen enrichment case reflects no change in unit costs from the base case. We have assumed that heaters and duct work will become smaller, but flue gas recycles will be required to avoid NOX and metallurgy issues.

- The main item resulting in cost change is the Air Separation Unit (ASU). There is also a slight increase in offsite costs for power imports and enriched oxygen piping. However, the additional boiler is eliminated (along with electrolytic hydrogen).

UG-7 Case: Flexicoking

- Flexicoking and conversion to syngas firing involves extensive cost increases throughout the facility. To accommodate the low Btu syngas, we have assumed extensive cost increases in heaters and fuel gas piping, reflected by a 5 to 10% unit cost increase for most units.

- In addition, the Flexicoker is significantly more costly than a delayed coker, primarily due to the gasification equipment.

- Hydrogen plant costs are less, as syngas shift reactors are cheaper much less expensive than SMRs or electrolysis.

- Offsite costs are increased reflecting larger syngas piping systems, essentially 10 times the natural gas system flows.

- While the cost for a Flexicoking upgrader is high compared to the base case delayed coking option, the cost is still more than 15% less than the cost of an upgrader with a traditional Gasifier.

Appendix 5: Upgrading Case Operating Cost Details

Table 1 is a summary of the estimated total annual operating costs developed for each case. The differences in operating costs for each new technology case, versus the base case, are discussed below.

UG-1 Case: Electrolytic Hydrogen

- Electrolytic hydrogen is significantly more expensive than SMR hydrogen, due to higher power costs and higher capital costs.

- An extreme breakeven price of $7 / MW-hr would be required to make this technology competitive.

UG-2 Case: Electric Reboiler

- As for SAGD operations, switching electric heat for natural gas firing requires a low capital cost. The added cost of electric heaters versus steam exchangers and natural gas fired heaters make electric heat more difficult to implement in an upgrading environment.

- To be competitive, electric heaters would require a credit for using electricity (i.e. costs less than zero).

UG-3 Case: Hot Oil System

- The hot system also requires an electric price below the heating value of natural gas ($14.3 / MW-hr), primarily because of higher fixed costs and CAPEX for implementing the hot oil system.

- The required power price would be $10 / MW-hr for electric hot oil heaters to be competitive with the base configuration.

UG-4 Case: Heat Pump

- As with electric heaters, the added fixed and capital cost for a heat pump will not justify the efficiency gains.

- An electricity credit would be required to justify this case versus the base configuration.

UG-5 Case: Vacuum Pump

- Replacing steam ejectors with electric power compressors increases non-energy prices and capital costs.
- The extra cost reduces the breakeven power price to $19 MW-hr, despite net efficiency improvements (lower total energy imports).

UG-6 Case: Oxygen Enrichment

- The efficiency gains from oxygen enrichment do not match the power requirements for the oxygen production.
- In addition, the facility costs go up and reduction in direct carbon emissions are due only to efficiency improvements.

UG-7 Case: Flexicoking

- Flexicoking has lower operating costs than the base case due primarily to replacement of natural gas with coke derived syngas (Flexigas™).
- This case has a higher annualized cost than the base case, due to higher capital costs. Still, this case has the highest breakeven power price of $82 / MW-hr, a level higher than the base case.

Additional Comments

- We have assumed hot oil systems (UG 3 Case) can replace more fired duty than can direct electric heating, which means higher electric costs and lower power costs. Because of increased electrical energy usage for roughly the same capital costs, this case has a slightly higher break even power cost.
- The heat pump case (UG4 Case) is more costly and achieves less energy savings than direct or hot oil systems. Because there is less replacement of natural gas, the costs are

lower, but the required break even cost is less than $25 / MW-hr because of the capital costs and loss of efficiency.

- Vacuum compression (UG5 Case) has the same operating cost as the base case despite higher fixed costs.

- Next to electrolytic hydrogen (UG 1 Case), oxygen enrichment (UG 6 Case) has the highest operating cost. This case also requires the lowest power price to be economic.

- Flexicoking (UG 7 Case) has a very lower operating cost consistent with gasification operations. As the operating cost is lower than the base case, the break even cost is higher than the base case price.

Table 1
Upgrading Technology Case Annual Operating Costs Summary

Case Description Are Operating Costs are 2012 basis		Units	Upgrader Base Case No Gasifier	Upgrader Base Case Gasifier	UG 1 - Electrolytic Hydrogen	UG 2 - Electric Heaters	UG 3 - Hot Oil System	UG 4 - Heat Pump	UG 5 - Vacuum Compressor	UG 6 - Oxygen Enrichment	UG 7 - Flexicoking & Syngas
Basis Data											
Athabasca bitumen		BPD	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Diluent		BPD	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000	66,000
Natural Gas		GJ/hr	5,511	0	1,630	5,023	4,766	5,267	5,087	5,088	30
Natural Gas Imports		MW	1,531		453	1,395	1,324	1,463	1,413	1,413	8
Power Imports		MW	100		1,410	174	203	122	145	274	224
Total Energy Imports		MW	**1,630**		**1,863**	**1,569**	**1,527**	**1,585**	**1,558**	**1,687**	**232**
Variable Expenses	**Price**										
Natural Gas	$4.38 /GJ	Mil $/YR	$213	$0	$60	$185	$175	$194	$187	$187	$1
Power	$77.2 /MW-hr	Mil $/YR	$65	$0	$914	$113	$132	$79	$94	$178	$145
Cat & Chem Cost	1.5% ISBL	Mil $/YR	$46	$73	$52	$47	$46	$47	$46	$51	$49
Water Costs	$0 /MT	Mil $/YR	$0	$0	$0	$0	$0	$0	$0	$0	$0
CO2 Penalty	$15 /MT	Mil $/YR	$59	$98	$19	$56	$54	$57	$56	$57	$62
Total Variable Expenses		Mil $/YR	$382	$171	$1,045	$401	$407	$377	$383	$473	$257
Fixed Expenses	**4.5% of TIC**	Mil $/YR	$246	$344	$295	$260	$260	$260	$257	$275	$280
Total Expenses		**Mil $/YR**	**$628**	**$514**	**$1,340**	**$661**	**$667**	**$637**	**$640**	**$748**	**$537**
Delta Expense		**Mil $/YR**			**$712**	**$33**	**$39**	**$9**	**$12**	**$120**	**($91)**
Annualized Costs (10% CAPEX+ OPEX)		Mil $	$1,170	$1,280	$1,940	$1,210	$1,220	$1,190	$1,190	$1,330	$1,160
Break Even Power Costs		$ MW-hr	-		**$6.7**	**$0.0**	**$10.4**	**$0.0**	**$19.2**	**$0.0**	**$82.4**

Appendix 6: Upgrading Case Operating Risk Issues

UG-1 Case: Electrolytic Hydrogen

- Process Complexity – Compared to reformer hydrogen, electrolytic hydrogen is a relatively simple process. Adding additional steam boilers will increase complexity.

- Operator Interaction – Assuming issues with equipment size can be addressed operator attention-level for electrolytic hydrogen operations should be equivalent to that for SMR hydrogen.

- Operator Training – Some operator training will be required for electrolytic hydrogen and steam boilers.

- Maintenance Requirements – Maintenance requirements may increase around hydrogen production cells.

- Reliability – Similar reliability to SMR expected.

- Overall: Electrolytic Hydrogen should not excessively increase operating risk relative to SMR Hydrogen.

UG-2 Case: Electric Reboilers

- Process Complexity – Electric boilers should be simpler to operate than steam or process heat exchange. There are fewer parameters to monitor.

- Operator Interaction – Properly automated, electric reboilers should require less operator interaction than equivalent steam exchangers. While process control should not be difficult, operators will need to closely monitor surface temperature and the impact that has on exchanger fouling.

- Operator Training – Some operator training will be required for electric reboilers.
- Maintenance Requirements – Cleaning of electric exchangers may require new equipment and techniques. The maintenance requirement will be closely tied to the operator's ability to control exchanger fouling and coking.

- Reliability – Since there is little refining industry experience with electric heaters, the reliability of these exchangers in heavy hydrocarbon service must be established.

- Overall: Given the uncertainty of maintaining reliability with electric reboilers in heavy hydrocarbon services, we believe that this technology has the potential to increase upgrader operating risk.

UG-3 Case: Hot Oil Systems

- Process Complexity – The complexity of a hot oil system is not in line with other utilities such as fuel gas and steam systems.

- Operator Interaction – Operator interaction should not be higher for hot oil systems compared to steam or natural gas.

- Operator Training – Some minor level of operating training will be required for hot oil systems.

- Maintenance Requirements – Compared to steam or natural gas, there will be more rotating equipment for a hot oil system. This will be offset by a reduction in issues with steam traps and boiler cleaning.

- Reliability – Hot oil has the potential to increase reliability by sustaining operation during steam system or fired heater failures.

- Overall: Hot Oil systems should not excessively increase operating risk relative to steam and natural gas systems

UG-4 Case: Heat Pumps

- Process Complexity – Heat pumps significantly increase process complexity relative to a thermo-syphon reboiler because of the introduction of a compressor.

- Operator Interaction – Monitoring and controlling a compressor will likely increase operator interaction.

- Operator Training – Heat pumps are not common in refining or upgrading, and some operator training will likely be required.

- Maintenance Requirements – More maintenance will be required for the compressor, though exchanger fouling might be reduced by dropping the vaporization temperature.

- Reliability – Introducing a compressor to the reboiling system will likely reduce the plant reliability.

- Overall: Heat pumps have the potential to increase maintenance and operator requirements, potentially increasing the operating risk of the upgrader.

UG-5 Case: Vacuum Compressors

- Process Complexity – Compressors replace steam ejectors without increasing overall equipment significantly. Depending on compressor type and auxiliary equipment, this change does not reflect an increase in complexity.

- Operator Interaction – If properly designed, the compressor system should increase operating flexibility, although some increased operating monitoring and instrumentation will be required for compressors.

- Operator Training – Operator training should be the same for ejectors versus vacuum pumps.

- Maintenance Requirements – Vacuum pumps will require increased maintenance, which will be offset by eliminating cooling water exchanger cleaning.

- Reliability – Reliability of electric systems versus steam systems vary in different facilities. In theory, there should be very little difference between the reliability of the two. Ejectors should be more reliable than electric compressors.

- Overall: Vacuum compressors should not excessively increase the operating risk of a bitumen upgrader.

UG-6 Case: Oxygen Enrichment

- Process Complexity – In addition to a new utility system, oxygen can necessitate flue gas recycles and ducting that will significantly increase the complexity of refinery heaters.

- Operator Interaction – ASU and other oxygen systems require relatively little attention, but operator monitoring of heater operation will likely increase.

- Operator Training – Operator training around heaters will be more intensive.

- Maintenance Requirements – ASU will require maintenance as will flue gas induction fans, increasing maintenance relative to the base case.

- Reliability – Oxygen enrichment need not impact reliability provide heaters are designed for normal air firing. However, that may increase the overall cost impact of this technology.

- Overall: Oxygen enrichment will likely increase operator and maintenance responsibility, negatively impacting upgrader operating risk.

UG-6 Case: Flexicoking™

- Process Complexity – Compared to delayed coking, Flexicoking™ adds a level of complexity.

- Operator Interaction –There will like be additional operator responsibilities in controlling and monitoring the Flexicoking gasifier. Alternatively, coke handling will be reduced.

- Operator Training – New training will be required.

- Maintenance Requirements – Flexigas will increase the number of burners throughout the refinery. The coker air compressor and gasifier will also require significant maintenance, although coke handling equipment maintenance will be reduced.

- Reliability – While Flexicoking™ may be as reliable as delayed coking, the rest of the refinery will be dependent on the coker for fuel gas supply. This creates a potential for lower upgrader reliability and on-stream availability.

- Overall - Relative to delayed coking, Flexicoking™ will likely increase operations and maintenance intensity, negatively impacting upgrader operating risk.

Appendix 7: Sample Breakeven Calculation

Break Even Calculation – SAGD 1 Case

At the breakeven price, the base case annualized costs (adjusted for break even power price) will equal SAGD 1 annualized costs.

BCCost – OPP × $BCED_A$ + $\mathbf{BEPP_{C1}}$ × $BCED_A$ = C1Cost – OPP × $C1ED_A$ + $\mathbf{BEPP_{C1}}$ × $C1ED_A$

Solving for the break even power price

$$\mathbf{BEPP_{C1}} = \frac{BCCost - C1Cost - OPP*(BCED - C1ED)*24*DPY/1E6Y}{(C1ED - BCED)*24*DPY/1E6}$$

Where:

BCCost = Base Case Annualized Cost ($407.1 MM/yr) = Op Costs(@OPP) + TIC*0.1
C1Cost = SAGD 1 Annualized Cost ($603.6)
OPP = Original Power Price ($77.2 / MW-hr)
$BEPP_{C1}$ = Break Even Power Price ($ / MW-hr)
BCED = Base Case Electric Demand (26.7 MW)
$BCPD_A$ = Base Case Annual Electric Demand (16.7 MW*24*DPY)
C1PD = SAGD 1 Electric Demand (450.4 MW)
$C1PD_A$ = SAGD 1 Annual Electric Demand (450.4 MW *24*DPY)
DPY = Operating (Steam) Days Per Year (337.6 steam days/yr)

$$\mathbf{BEPP_{C1}} = \frac{407.1 - 603.6 - 77.2*(26.7 - 450.4)*24*338/1E6}{(450.4 - 26{,}7)*24*338/1E6} = \$19.9 \text{ \$/MWhr}$$

Appendix 8: SAGD Case Technology Status Summary

	Vendors	Largest Size Available (based on vendor information)	Scale-up Requirements (1)	Likelihood of Scaling
Central Processing Facility (CPF) electric boilers (SAGD-1)	Precision Gaumer Chromalox Cleaver-Brooks	4 MW @ High Pres. 10 MW @ Low Pres.	80 MW Req'd Geometry and mat'ls will need to be redesigned	Probably will be pursued when economically favorable
CPF steam compressors to reuse low-pressure steam (SAGD-1A)	GE Dresser Siemens	Air Max Size - 40 MW (Petrochem) Steam Max - 0.8 MW (Brewing)	100-200 MW Req'd Unlikely to exceed 40 MW size, possibly smaller for steam	Limits on steam compression related to ratio / heat curve
Electric boilers at the well pads to reuse condensate (SAGD-2)	Precision Gaumer Chromalox Cleaver-Brooks	4 MW @ High Pres	4 MW Req'd No scale up Required	
Well pad steam compressors to reuse condensate (SAGD-3)	GE Dresser Siemens	Air Max Size - 40 MW (Petrochem) Steam Max - 0.8 MW (Brewing)	3.5 MW per WP Steam compressor could be scaled up	Compression ratio and recycle requirements need to be defined.
Steam superheaters to reduce condensate formation (SAGD-4)	Chromalox Gaumer	2 MW	24 MW per CPF (2)	Scaling may be limited by pipe dimensions for stab-in heater
Reverse Osmosis (RO) make-up water treatment (SAGD-5)	Siemens GE	20,000 m3/d	3000 m3/d	RO Plants insensitive to scaling. Costs related to number of cartridges.
Mechanical Vapor Compression (MVC) evaporators (SAGD-6)	Veolia GE Siemens	6900 m3/d charge	27,000 m3/d Larger MVR sizes face economic constraints	Smaller MVR modules are more economic. (3)
Zero Liquid Discharge (ZLD) facilities (SAGD-7)	Veolia GE Siemens	6900 m3/d charge Train size can be larger w/ multiple MVR	27,000 m3/d Larger sizes face economic constraints	Train size dependent on technology selection and water quality

(1) Scale up requirements based on 40 KBPSD SAGD facility as per case summary

(2) This equates to total heat required to avoid condensing. The superheaters can be at the CPF or all along the steam line.

(3) Based on information from vendors, a larger size module will have to be stick-built instead of provided - built - by the vendor, which is more expensive. Information from vendors suggest that the cost will be higher on a per barrel basis.

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