

PNEUMATIC PUMP ALTERNATIVES FOR COLD WEATHER





A C K N O W L E D G E M E N T S

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EXECUTIVE SUMMARY

The international, federal and provincial political landscape has evolved to increase emphasis on climate change and methane emissions from the oil and gas sector. Emissions from natural gas-driven pumps are identified as a significant source of methane emissions from the sector (Environment Canada, 2014; and CAPP, 2008). As a result, the industry is actively pursuing alternatives to gas-driven chemical injection pumps as a means to reduce venting emissions. Estimates of the number of gas-driven chemical pumps in the Western Canadian Sedimentary Basin are highly variable, but a quantity in excess of 100,000 is possible based on the Alberta Upstream Oil and Gas Assets Inventory Study (2013) and inferences from the Province of British Columbia's Greenhouse Gas Reporting Regulation.

Alternatives to natural gas-driven pumps can be grouped into three categories: powered (solar, fuel cell, grid tied), mechanical (instrument air, methanol sphere) and vent capture systems that combust or conserve the exhaust from pneumatic pumps (vent gas for low pressure fuel, vapour recovery units). Based on research undertaken by GreenPath Energy Ltd., there are multiple alternative technologies with no one optimal alternative to a gas-driven pump for all situations. Alternatives to a gas-driven pump may not be economically feasible but could be technically feasible.

The Montney and Duvernay formations are expected to lead production growth in Canada over the medium term and are high-rate wells, with pressure and liquid injection requirements that may dramatically increase the cost of pneumatic alternatives due to increased power requirements. As GreenPath Energy was unable to obtain pressure information from more than one producer, a more detailed understanding of pressure and rate effects on pump alternatives will be useful for future study.

Chemical injection pumps running on natural gas are mostly found in remote locations. The most common alternative to a gas-driven pump is a solar chemical pump (SCP) that relies on solar panels, a battery back-up, and an electrically-driven pump.

Based on a combination of on-site inspections as well as operator interviews, solar chemical injection pumps are in operation from Dawson Creek, BC to Fort Nelson, BC as well as the Rainbow Lake area in Northern Alberta. Early solar chemical injection pumps – plagued by issues adapting to Canadian operating conditions – continue to negatively bias operator opinions on the effectiveness of solar chemical installations. Solar chemical injection systems were found to be reasonably common in the low light, cold weather and high-pressure conditions found at producing facilities in the Montney formation, an area where conventional logic suggests solar chemical injection systems should not perform well. The key variable in determining whether or not these systems are installed tends to be operator preference and economic considerations as opposed to any technical limitation. This report will detail the economic and technical strengths and weaknesses associated with alternative technologies.

Currently, SCPs are the most technically-viable alternative to gas-driven chemical injection pumps, and appear to be more broadly accepted than other powered and mechanical variations. Several other technologies (both old and new) address emissions from gas-driven chemical injection pumps in remote power situations.

Most non-solar technology alternatives are not sufficient for widespread deployment. Like most other remote technologies, solar chemical pumps are not economically favourable unless natural gas prices increase significantly over current forecasts, or setting a carbon price on vented methane.

While other emerging technologies such as hybrid fuel cell systems show promise, they do not appear to be deployed in significant numbers or for a sufficient length of time to comment on their long term viability. Using vented natural gas from chemical pumps for low-pressure fuel demands (e.g. catalytic heaters) is a promising low-cost option which deserves further field testing to resolve back pressure, and gas supply and demand

challenges (vent gas capture system). Fuel cells appear to be a promising technology alternative, with cost and reliability as major concerns at this time. The best possible alternative from a greenhouse gas and reliability perspective is grid-tied electricity from a renewable source, combined with an electric motor; however, the remote nature of some Canadian oil and gas operations makes this solution challenging to deploy.



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INTRODUCTION

Gas-driven pumps are a common feature of the oil and gas industry in the Western Canadian Sedimentary Basin (WCSB) and are used to accomplish a number of activities, the most common being chemical injection at wellsites and facilities. An open question within the oil and gas industry is the viability of alternatives to gas-driven pumps in different applications, the most pressing of which relates to chemical injection.

Estimates of gas driven chemical injections vary considerably, with an estimate of over one million in the oil and gas industry globally¹, to over 165,000 in Alberta². Emissions from this source are potentially a large contributor to greenhouse gas (GHG) emissions, with estimates from emissions from gas-driven pumps ranging from ~4otCO₂e (metric tonne of carbon dioxide equivalent (1996 Radian)³) to ~14otCO₂e (Prasino Study) per unit per year; some examples have been found to exceed 2,00otCO₂e.

Significant variability in terms of the volume per device as well as the number of devices creates a great degree of uncertainty with regard to the emissions from this source as well as the potential abatement opportunity. The BC Reporting Regulation, based on emission factors, has potential to incorrectly estimate emissions from this source. Assuming 10,000 operating wells and facilities using fuel gas for chemical injection, and each well having one chemical injection pump (per the Cap-Op Asset Inventory Study), the reporting regulation could be underestimated by a factor of 2 to 5. Conversely, due to the load factor of methanol, the figure in the BC Reporting Regulation could be overstated by 30% to 50%.

Pneumatic inventories generated to support third party verification under the BC Reporting Regulation could be used to support the development of company programs for pneumatic pump transitional programs.

On-site measurement of key parameters such as liquid injection rates, injection pressure, topography and well life must be captured before alternatives can be evaluated, and pneumatic inventories developed for the BC Reporting Regulation would have to be supplemented with liquid injection rates and pressure information to develop a pneumatic pump transition plan.

The effectiveness of alternatives to gas-driven pumps are not broadly accepted within the oil and gas industry, as certain companies view some alternatives as economically and technically feasible, and others view gas-driven alternatives as infeasible due to the unique circumstances of Canadian oil and gas production (e.g. low available light at northern latitudes and cold temperatures).

POLICY CONTEXT

Methane emissions from the oil and gas industry have come under increased scrutiny, with particular attention to the global warming impacts of methane vented to atmosphere. The EDF/Pembina Study⁴ by ICF on methane abatement highlighted solar chemical pumps (SCPs) as a cost-effective alternative to gas-driven chemical injection pumps.

Recent policy announcements by the United States Environmental Protection Agency (U.S. EPA) and by the governments of Alberta and British Columbia emphasize the importance

¹ Efficient Use of Fuel Gas in Chemical Injection Pumps”, Module 5 of 17, Submitted by CETAC West, May 2008

² Alberta Asset Inventory Study

³ http://www3.epa.gov/gasstar/documents/emissions_report/2_technicalreport.pdf

⁴ <https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf>

⁵ http://www3.epa.gov/airquality/oilandgas/pdfs/natgas_well_site_summ_o81815.pdf

of understanding economic costs and technical limitations of gas-driven pump alternatives in the Canadian context.

U.S. EPA proposed New Source Performance Standards (NSPS) have suggested that gas-driven chemical injection pumps for new and modified sources must have the exhaust routed to a destruction device, when one is present⁵. The Canadian federal government has indicated it wishes to harmonize oil and gas rules with the draft U.S. EPA Regulation. Regionally, Alberta has committed to reduce methane emissions from the oil and gas industry by 45% by 2025, and the BC Climate Leadership Team has recommended a 40% reduction in methane from the sector by 2020. For this objective to be achieved, emissions from gas-driven pumps will have to be reduced significantly. There is a window of opportunity for industry to take the initiative to reduce methane emissions should costs associated with increased regulation or from carbon tax expansion materialize and affect industry.

During this window of opportunity there will likely be potential for carbon savings from methane reduction via the carbon-offset system (Alberta) or the proposed Clean Infrastructure Royalty Credit Program (CIRCP) in British Columbia, and offsets if government procurement policy changes or LNG exports occur. The Clean Infrastructure Royalty Credit Program is expected to operate like other royalty credit programs in BC (such as the Infrastructure Royalty Credit Program), where deductions on royalty payments may be available for eligible projects.

STUDY METHODOLOGY

This report aims to assess economic and technical feasibility of commercial and near-commercial alternatives to gas-driven pumps in Western Canada, with particular attention to technologies that perform at northern latitudes and cold climates. This study is based on a desktop review as well as site visits and interviews.

The desktop review of current Climate and Change and Emissions Management Corporation (CCEMC) and Sustainable Technology Development Canada (SDTC) set to determine which technologies might be in development (or nearing commercial deployment) that may be used to replace pneumatic pumps in cold climates. The most common emerging technology revealed from this review is methanol-based fuel cells, detailed in the technology overview.

The most common pump alternative is an electric pump with power supplied either via on-site generation (diesel or natural gas generator set, or a thermal electric generator), a solar/battery system or grid-tied electricity.

Vendors for solar pump systems were contacted to obtain information on sales of systems in northern latitudes, including:

- Sirius Controls
- Trido
- MCI Solutions
- Calscan
- Ace95
- Evergreen Technologies
- Ensol Systems
- Gentherm Global Power Technologies

GreenPath had an established relationship with each of these firms prior to project initiation; these firms were helpful in providing approximate sales figures and areas of high concentration.

The precise location of installations were not provided due to confidentiality concerns, but approximate sales figures and a list of clients were provided. A comprehensive data set for the number and locations of pneumatic pump alternatives does not exist; however, data from the BC Greenhouse Gas Inventory is likely superior to reports from industry or other Canadian provinces.

⁵ <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=47B640C5-1&offset=6&toc=hide>

The BC Reporting Regulation includes a definition for “releases from pneumatic devices that use natural gas as a driver” as part of “venting emissions”⁶. Also, since this study is to investigate high latitude and low temperature locations, the Dawson Creek and Fort St. John area became a focus area for data and analysis.

Drilling has been active in the Montney area for the last decade in which solar pumps have been available, and a high percentage of operators have a reporting requirement in BC requiring the development of a pneumatic census. In addition, the Montney formation often has high initial pressures during the early life of each well, which has also been viewed as a major limitation to the most common type of gas-driven pump alternatives (Solar Chemical Injection).

In the course of regular site visits, GreenPath staff also used a tablet-based data capture system to record details on solar systems noticed during regular optical gas imaging inspections.

Vent gas emission rates were also measured at two wellsites in BC in order to develop a baseline emission rate prior to the installation of two Calscan solar-electric well packages (consisting of electric pumps, controllers, actuators, batteries, and panels). This system is unique in that it has the ability to capture data on strokes (thus chemical injected) and on the actuation of dump valves. This system will be re-visited to assess its performance.

TECHNOLOGY OVERVIEWS

BASELINE TECHNOLOGY – GAS-DRIVEN PNEUMATIC PUMPS

In upstream oil and gas operations, positive displacement piston- or diaphragm-actuated pumps are used to inject relatively small amounts of chemicals, which enable processing and production. These pumps leverage available pressurized fuel gas as the motive force to inject chemicals into pressurized process streams, venting fuel gas to atmosphere with every stroke.

Gas-driven pneumatic pumps are sometimes used to circulate a fluid such as glycol for “heat tracing” pipelines and other equipment to prevent freezing. Although significant emitters, gas-driven heat trace pumps are not the focus of this study given their low population.

Figure 1: Gas-driven methanol diaphragm pump



OPERATIONAL EXPERIENCE

Gas-driven pneumatic chemical injection pumps are a reliable and proven technology with a number of weaknesses that may make non-gas driven alternatives viable; for example, increased operating and maintenance costs in cases with wet fuel gas may render other alternatives more suitable from an economic or operational perspective.

At sour gas sites, the cost of piping “clean” fuel gas to site may render other alternatives more economically favourable.

In terms of mitigation technologies, the solution to methane venting from pneumatic pumps can be grouped into: power on site (a mechanical system where access to electricity is not feasible), or scenarios where exhaust gas is conserved.

OVERVIEW OF ALTERNATIVES

The following tables describe operating principles for each alternative, as well as advantages and limitations, cost implications, and operational experience.

Table 1: Categories of gas-driven pump alternatives

POWER	MECHANICAL	EXHAUST CONSERVED
Solar system	Methanol Spheres	Vent gas capture at wellsites
Solar hybrid (fuel cell or TEG)	Plainsmen	VRU to Flare
Grid-tied	Instrument air	
Self generation (TEG)		

Table 2: Alternatives to gas-driven pumps in oil and gas

TECHNOLOGY	PROVIDERS	STRENGTHS	WEAKNESSES	CAPITAL COSTS	OPEX COST OBSERVATIONS
Solar chemical pump (SCP)	Sirius Texsteam Trido Calscan	Most common No issue with fuel gas quality Precision on chemical injection rates May upgrade to all electric Lower maintenance than pneumatic in some cases	Sunlight limitations Pressure limitations High capital expenditure Battery operating expense Prone to theft and vandalism (e.g. target shooting of solar panels)	\$7,500 (incremental greenfield) to \$16,200	Increased precision on liquid injected volumes (e.g. 5 litres per day to 3 litres per day) or (@\$7/litre = \$5,000/year if injected 365 days/year

TECHNOLOGY	PROVIDERS	STRENGTHS	WEAKNESSES	CAPITAL COSTS	OPEX COST OBSERVATIONS
Blair Air		No operating expense on batteries Able to manage pumping control elements	Requires pressure differential at site Well flowing required Few installs High cost	Variable up to \$41,000	No battery replacement costs
510 Enviro Pump	Plainsmen	Low cost	Requires pressure differential at site Well flowing required for operation No known installs	\$1,850	Compatible with Texsteam 5100
Vent gas capture for low pressure fuel	Conoco-Phillips pilot	Low cost	Backpressure on pumps may cause stalling, matching load (Cata-Dyne) and fuel (pump)	\$6,500	
Methanol Spheres	ARGO	Low cost No moving parts	Approved in Alberta only ⁷ Unable to handle high injection volumes Pressure limitation	\$3,800 to \$7,700	Increased filling costs
Hybrid fuel cell	EnSol EverGreen	Common platform (EFOY) Less sunlight required	Methanol cost Capital cost Fuel cell lifespan	Over \$30,000	Cost of methanol cartridges
Hybrid TEG	Sirius	Low sunlight concerns	Increased cost	~\$25,000	TEG fuel consumption (marginal)

⁷ The BC Safety Authority does not have similar regulations for pressure vessels for the intended use. In addition, methanol spheres are likely only viable for low pressure wells with low injection rates, of which there are few in British Columbia.

TECHNOLOGY	PROVIDERS	STRENGTHS	WEAKNESSES	CAPITAL COSTS	OPEX COST OBSERVATIONS
Full TEG	Gentherm Global Power Tech	No sunlight issues No moving parts	High cost Load limitations	Variable can be greater than \$60,000	
Self-generation and instrument air	Texsteam Arrow (Engine)	No change in tech for operator Lower emissions	Sizing of generation sets, sufficient load to justify CapEx Fuel costs and quality	Highly variable >\$250,00 for large system	Generator fuel marginal ~\$8,000/year
Grid-tied electric	Texsteam Sirius	Comparable in cost to pneumatic (excluding transmission/generation)	Requires grid connection or onsite generation	Marginal cost on electric vs pneumatic pumps (\$1,000 to \$2,000). Costs variable on distance to electric distribution infrastructure	Annual electricity costs marginal, ~\$10,000/year

Table 3: Production types and preferred gas-driven pump alternatives

PRODUCTION TYPE	PREFERRED ALTERNATIVE TECHNOLOGY
Low-pressure, low rate well	Methanol sphere
Multi-well pad (>8 wells)	Self-generation + instrument air or electric pumps
Methanol Injection (seasonal)	Vent gas capture for low pressure fuel
Wet fuel Gas	Solar chemical
Sour site	Solar chemical
Non-remote site	Grid-tied – electric pumps

Table 4: Known installations of pump alternatives

TECHNOLOGY	KNOWN INSTALLATIONS	NOTES
Solar chemical pumps	Thousands	Appear to be limitations regarding initial pressure and battery life experience variable
Blair air	5	High cost, requires continuous flow on well
Plainsmen EnviroPump 510	None	Requires pressure differential, no known installs.
Vent gas capture for low pressure fuel	15	Pilot project by ConocoPhillips, third party device "BackPack" no longer marketed
Methanol spheres	Currently unknown; in use in southeast Alberta	Old technology, recently approved in Alberta
Hybrid fuel cell	100s	Evergreen CCEMC funded project
Hybrid TEG	25	BP Noel Project (currently owned by CNRL) System status unknown
Grid-tied electric	100s	Limited incremental cost when power available, key issue is access to transmission

SOLAR CHEMICAL PUMPS

Solar chemical pumps (SCP) operate by capturing solar energy via solar panels to run an electric motor and storing the surplus in battery banks for when sunlight is lacking. The electric motor of the SCP replaces the positive displacement pump commonly used in gas-driven pneumatic pumps. The key limitations of SCP have been associated with the lack of available sunlight in particular geographies and cold ambient temperatures, which can negatively impact battery performance.

In addition, concerns have been raised with the ability of solar systems to handle the high rates and pressures of modern tight and shale gas wells. Data from vendors suggests that modern pumps can handle pressures up to, 4,350 PSI; a vendor in the United States reported a solar pump able to handle pressures up to 10,000 psi.

An operator with significant assets in Montney noted that injection typically occurs at the flow line, generally less than 600 psi; that injection into the wellhead is uncommon; and that reliability issues related to the power requirements of injection into the process stream (which may be a function of an improperly sized system) emerge when pressure is greater than 1,500 psi.

A solar chemical pump is the most common alternative to gas-driven chemical injection, with thousands of deployments in the Western Canadian Sedimentary Basin. Opinions range on the effectiveness of solar chemical pumps at northern latitudes by operators, by operator within operational units of companies. Some operators indicate that solar chemical systems do not operate well at latitudes north of Edmonton, and others view solar chemical injection systems as the design default in the Montney-Duvernay area.

Mixed opinions on solar chemical pumps are largely due to how solar chemical pumps were introduced into the Canadian oil and gas marketplace. The earliest solar chemical pumps in the Canadian market appeared in approximately 2004, adapted from agricultural pumps used in the southern United States. These systems did not perform well, particularly at northern latitudes. Simple issues such as the orientation of the panel (a 45° angle instead of perpendicular to the ground provides more energy at southern

Figure 2: Solar chemical pump installed south of the 49th parallel



SCP providers have asserted that SCPs reduce chemical consumption and generate cost savings due to the ability to precisely control quantities of chemical injected versus pneumatic equivalents. The rationale for this phenomenon is that with pneumatic devices the injection pressure “drifts” as the well delineates. The relatively crude control systems on pneumatic controls often result in cases of over-injection. For example, there is a significant consequence to insufficient injected methanol in terms of reliability and safety; the measurable consequence of over-injection is higher methanol injection costs.

An analysis of injected volumes from a producer showed a pattern whereby under-injected volumes were relatively small (<10%) but over-injected volumes were very significant (greater than 50% targeted

latitudes; instead, perpendicular to the ground in northern latitudes) were not addressed. Batteries and panels were undersized. Second-generation SCPs were reliant on older pneumatic pump technology with an added solar power system. These hybrid pneumatic/solar systems (an electric motor running a pneumatic diaphragm) had few benefits of a fully electric solar system (such as greater injected liquid volume precision). The latest iteration of solar pumps are purpose-built for applications for oil and gas.

Figure 3: Solar chemical pump installed north of the 49th parallel



injection rate). From a risk perspective, operators have a preference to over-inject rather than under-inject.

SCPs are capable of injecting at lower pressures than pneumatic pumps as pneumatic pumps risk stalling at low rates. Thus, if chemicals can be injected at a lower rate, there may be a cost savings opportunity when a solar pump can be employed in place of a pneumatic pump at low rate applications. Some chemicals used by the oil and gas industry exceed \$7/litre; therefore, significant costs savings can accrue; for example, moving from 5 litres to 3 litres per day equals \$5,100 per year savings if injecting 365 days a year. Saving on these costs would pay for the cost of the solar system, but quantification of these savings has proven difficult.

OPERATIONAL EXPERIENCE

The experience of operators of solar chemical injection systems is highly variable. Overall, operators that installed first- or second-generation solar chemical pump systems experienced issues with battery life and/or sizing of the solar systems.

Solar chemical pumps are more common in greenfield conditions as the incremental cost is significantly lower than a retrofit case, where generally a solar pump is only brought in to solve an operational concern with a pneumatic pump such as fuel costs or stalling from low injection volumes.

Table 5: Solar chemical pumps generation 3 strengths and weaknesses

STRENGTH	WEAKNESS
More precise injection volume	Prone to vandalism and theft
Ability for “intelligent” injection (Methanol/H ₂ S Scavenger)	Layout issues
Fuel gas quality not an issue	Perceived reliability
	Operator preference
	High pressure and rate configurations

One of the most common challenges related to solar systems relates to the issue of vandalism and theft. Solar panels are visible from a significant distance and used for target practice. Fortunately, even with several bullet holes in a panel, the system should have negligible power loss provided the wiring has not been compromised. In the event of damage via bullet holes, the integrity of the system can be checked via voltmeter; the panel can be replaced if a significant power loss has occurred. A more pressing concern relates to theft: according to a top producer in Canada, the most commonly stolen items from a site are copper wire and solar panels.

A key issue with early solar installations related to the sizing of batteries and solar panel systems. An installer interviewed by GreenPath who conducted over 200 installations on behalf of Encana in the greater Sierra area proved instructive. Based on his recollection, the initial system was grossly undersized and unreliable. The installer indicated that the solar chemical systems that were sized appropriately (sometimes increasing panels by a factor of two and batteries by a factor of up to three) worked well during his three years managing the solar installs.

A key development has been the development of tools by SCP providers to accurately size solar installs taking into account the latitude, injection pressure, liquid injected and reserve margin. These tools allow for a greater probability of a successful installation as opposed to early installs which simply multiplied the initial battery and panel configuration to the point where the system operates. Sizing of a solar system is largely not a “one size fits all” approach, even within a field; different terrain conditions and injection requirements require a different sizing of systems.

Another issue discussed at length with regard to solar chemical injection systems has been the possibility that tree cover may inhibit the performance of a solar system by decreasing the available light for the solar-based system. Based on a study of common tree species in Northeast British Columbia, the average tree height is 17.2 metres⁷. Planning data from the BC Oil and Gas Commission indicates the cleared area for a multi-well pad ranges from 4 hectares to 8 hectares, and 12 hectares for a Liard well. Thus, assuming the smallest

⁷ Chen et Al (2004) Variation of the understory composition and diversity along a gradient of productivity in Populus tremuloides stands of northern British Columbia, Canada
<http://flash.lakeheadu.ca/~hchen/papers/Chen%20et%20al.%202004%20CJB.pdf>

footprint of 4 hectares, a square clearance area (200 metres per side), tree cover on all sides, the panel at the centre of the pad, and the solar panel at the bottom of the mast, the shortest distance from tree cover to pump location is 100 metres. Using simple trigonometry and latitude/longitude, this will cut available sunlight for a few hours during winter, requiring additional reserve margin on the system, creating additional cost but is not a significant operational issue in most cases.

One major advantage of solar-based systems and other powered solutions relates to the ability to control the injection rate. In analysing ConocoPhillips's data on chemicals injected by gas-driven pumps, a pattern of small under-injection and large over-injections emerged. Electric pumps (with more sophisticated controls) allow for greater precision of the volume injected. With exotic chemicals such as corrosion inhibitors, de-foamers and H₂S scavengers which can exceed \$7/litre, removing these over-injection events would result in significant cost savings.

One of the most common uses for gas-driven chemical injection pumps is methanol injection to prevent hydrate formation. Hydrate formation is governed by pressure and temperature, with pressure being the dominant factor in determining hydrate formation. A Sirius Controls customer was able to build the hydrate formation curve for their operations into the controller of the methanol pump, thus modulating methanol injection rates based on ambient temperature and pressure, which would result in a savings in methanol costs. In other cases, temperature sensors are used to simply shut off the chemical injection pump in warm temperatures.

Electric pumps also have the ability to inject more than one type of chemical using a single pump at different chemical injection rates, thus offering a lower incremental cost relative to gas-driven pumps, which require two gas-driven pumps to accomplish the same task. A common configuration is methanol injection (high rates) and corrosion inhibitor (low daily

rate). The addition of this capacity does add some extra cost depending on the configuration (approximately \$1,000).

In terms of modern multi-well pads, a major limiting factor in solar systems has been revealed. With high-pressure wells, injecting into the wellhead solar chemical pump may not meet pressure requirements (e.g. over 4,500 psi), or may require significant investment in batteries and panels, which then increases costs. This is a critical issue to address from a GHG perspective, as the emissions from a gas-driven pump are a function of the pressure of the process stream being injected into, and of the volume of chemicals injected. Assuming a pressure of 1,100 psi, injection volume of 200L/day if over 365 days' service a single pump would exceed 1,000 tCO₂e/year. The number of panels and batteries required would generate above-normal costs and create challenges for siting.

A potential alternative is to install electric motors and temporary generators during these high initial rates and transition to a solar or solar hybrid system when the well has delineated. It is important to note that potential high rate and high GHG emission chemical injection are currently not reflected in the BC GHG Reporting Regulation inventory, as most pump emissions are reported on an emission factor basis of pump count multiplied by well operating hours. Similarly, the emissions from "seasonal" or "as needed" chemical injection systems are likely over-reported.

There are also a number of user interface problems with some solar setups. For example, at one site, the operators described challenges with the solar system with removing blockages of snow, which had accumulated on the tank and then draining into secondary containment and frozen; this issue could be alleviated via the addition of a roof over the tankage.

Another issue highlighted was that the filter for the chemical tanks was difficult to access and could not use a standard filter, requiring a smaller and specialized filter.

Taking input on design and layout from end users would serve to enhance buy-in at the field level and thus increase successful installations.

SELF-CONTAINED SYSTEMS (PLAINSMAN/ BLAIR AIR SYSTEM)

GreenPath examined two chemical injection pump solutions, which both rely upon a pressure differential at site to drive a chemical injection pump. Neither system vents to atmosphere. Systems that rely on harnessing pressure differential at site are, however, a concern for operators as relying on this pressure differential may cause a flow reduction on low-pressure wells. This may also be an issue in older wells that may produce intermittently if the injection process is required when the well is not producing.

The Plainsman 510 Enviro Pump uses the existing body of a Texsteam 5100, and is a relatively low cost method of eliminating emissions from a Texsteam 5100; however, there are no known operating installations of this system, therefore it is difficult ascertain their performance in the field. GreenPath has estimated the installation cost of the system based on hands-on time with the system. One potential issue identified by GreenPath was that the differential pressure on-site that the 510 Enviro Pump relies upon is not sustainable as pressure declines.

OPERATIONAL EXPERIENCE

The Blair Air system uses the pressure energy to power a drive a cylinder that runs a piston pump and/or a compressor; thus, methane is not vented to atmosphere in the course of normal operations. The system is not a replicable off-the-shelf technology like the 510 Enviro Pump, and is instead tailored to each installation. Encana had previously had a Blair Air installation at one of their facilities; however, the asset was sold and the Blair Air system only operated for a limited time.

The main issues with the Blair air system are:

1. Costs as quoted are relatively high relative to other systems.
2. Each installation is unique, limiting the ability of the technology to drive down costs in order to compete with solar and other alternatives.
3. The inventor of the Blair Air system (Jim Blair) is a sole proprietor. As such, the product is not represented by distribution, creating limitations regarding supply, servicing and maintenance.

VENT GAS CAPTURE FOR LOW -PRESSURE FUEL (VENT GAS CAPTURE SYSTEMS)

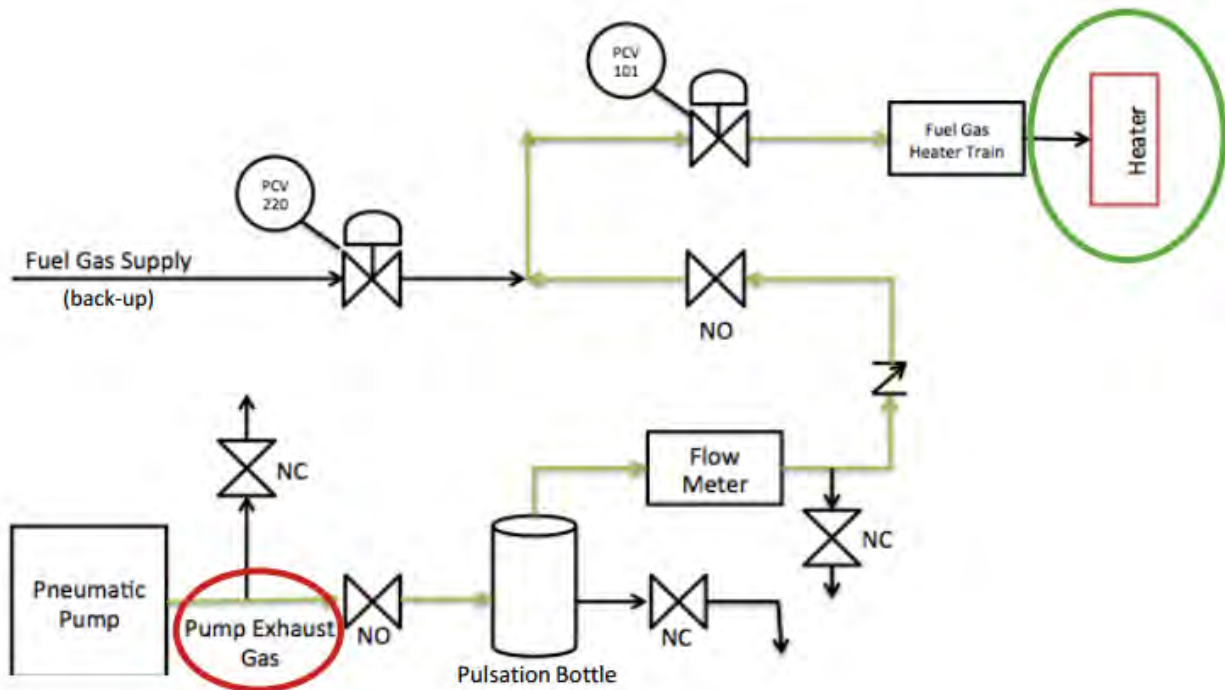
The vent gas capture system takes the exhaust from a gas-driven chemical injection pump, stabilizes the flow via the pulsation bottle, and sends the otherwise vented gas to the Cata-Dyne heater on site. Flow from the chemical injection pump to the heater is metered, which would support carbon offset verification. If the Cata-Dyne heater requires supplemental fuel, it is pulled from the fuel gas system.

ConocoPhillips implemented a vent gas capture system at a handful of wellsites as part of their Climate Change and Emissions Management Corporation (CCEMC)-funded energy efficiency project, which routed the exhaust from the gas-driven chemical injection pump to the fuel supply system for a Cata-Dyne heater.

A portion of the otherwise vented fuel gas is used as fuel gas for the Cata-Dyne heater, reducing the operating cost of the Cata-Dyne heater as well as reducing the global warming potential of the fuel gas of the chemical injection pump via combustion.

Originally, Supplier Pipeline Group (a third party) provided a system called a “Backpack” which used vented gas from pneumatic pumps to supplement the fuel gas system for heaters. The Supplier Pipeline Control product does not appear to be available on the market, hence the rationale for ConocoPhillips to develop their own system.

Figure 4: Vent gas capture system schematic



The key issue with this pneumatic pump alternative is the sizing of existing chemical injection pump venting and Cata-Dyne heater demand. In the ConocoPhillips project methanol chemical injection pumps were prioritised, as they have high vent rates, and are typically only operated in winter, which matches the seasonal requirements of Cata-Dyne heaters. One issue that was challenging for the project was that back pressure from the Cata-Dyne heater could cause the chemical injection pump to stall, making site selection and early measurement key to a successful implementation.

Currently, there is no known third party provider of the system as ConocoPhillips implemented as part of the CCEMC project, and to date there have only been 15 implementations. Data from this trial will be useful to evaluate performance and assess for effectiveness going forward. The Vent Gas Capture system deployed by ConocoPhillips is very interesting in that it ties a seasonal venting load (methanol injection) to seasonal heating loads of Cata-Dyne heaters.

Key issues for consideration are:

1. Destruction efficiency of the Cata-Dyne heater⁸
2. How to accurately match fuel supply from pump with demand from heater
3. Backpressure on pumps can result in stalling.

The technology appears promising and there are a number of potential pathways to resolve identified issues. For example, if pumps are adjusted so fuel supply is at a higher pressure, this may reduce the risk of stalling. Ideally, vent gas could be supplied to a fuel header to supply multiple Cata-Dyne heaters, minimizing the issue of matching output from the pump to end uses of the fuel.

METHANOL SPHERES

A methanol sphere is an old technology for chemical injection that has recently become viable again due to changes in ABSA⁹ related to pressure vessels. This was the most common method of chemical injection in earlier years, and may be alternative for low pressure and low rate applications. In this case, a sphere (filled with a chemical such as methane) has the fuel line at the top of the sphere, and at the bottom has a needle designed to control injection rate. The pressure in the sphere is equal to the supply and injection pressure.

The sphere can handle pressures up to 1440 psi, but capacity is limited to 330 litres (88 gallons). The low capacity requires more operator visits to site to reload the sphere, estimated at twice per month in injection season based on typical injection volumes (~20L/day).

GreenPath was unable to obtain qualitative data on methanol sphere installations.

Potential limitations of the system include the need to refill more than annually at higher than 1L/day applications; as such, these are not a good alternative for remote sites, as operating costs related to filling could reduce the economic feasibility.

The methanol sphere system is small and it would be beneficial in site with a constrained footprint.

Figure 5: Methanol sphere installation



⁸ Hayes *et al.* 2009. Catalytic combustion of VOC in a counter-diffusive reactor *Catalysis Today* 155 (2010) 147–153 suggests destruction efficiency of approximately 60%

⁹ Exemption for methanol injection tanks in section 2(1)(f)(iv) of the Pressure Equipment Exemption Order (AR 56/2006)

HYBRID FUEL CELL SYSTEMS

There are two known suppliers of combined of solar power and methanol based fuel cell systems: Ensol Systems of Surrey, BC, and Evergreen Energy Technologies Inc. (ETI) of Calgary, AB.

Both suppliers both rely upon the EFOY¹⁰ Fuel Cell system provided by SFC Energy of Brunthal, Germany. EFOY fuel cells rely on highly refined methanol cartridges to generate power – highly durable but very expensive.

Figure 2: Hybrid fuel cell/solar system



This hybrid system uses the fuel cells to supplement battery power when sunlight is unavailable. The methanol cartridges do not have the same operational concerns as batteries related to cold weather, and are significantly lighter than batteries, making them more suitable to be deployed to sites that are helicopter-only access and where weight concerns may be an issue. Similar limitations exist in terms of relying upon an electric motor, which put an upper limit upon the maximum pressure at which these pumps can operate.

The number of installations for chemical injection pump service is unknown at this point. Evergreen technology has asserted that over 100 of these systems have been sold in Western Canada.

The Climate Change and Emissions Management Corporation (CCEMC) funded a project for Evergreen Energy Technologies Inc.; the results suggested that the technology was not highly promising for this application; that improvements were required before Evergreen's Power Pod System could be widely deployed; and that capital costs would be well above that of a solar system.

The main barrier to the most common hybrid fuel cell system is the initial capital cost, which exceeds \$30,000 in most applications. In addition, both Evergreen and Ensol rely upon methanol cartridges from Germany, which add complexity to the supply chain for implementation. Other applications are looking at the use of field grade methanol to minimise the cost and logistical challenges related to the methanol based systems.

OPERATIONAL EXPERIENCE

Despite the purported number of installations of fuel cell systems in the field, no operating fuel cell-based solar systems could be found. In terms of interviews with packagers, three primary issues appeared:

1. Methanol fuel – options are to refine on-site to remove impurities that cause the fuel cell to “plate out” which reduces output or rely on refined methanol cartridges (EFOY system)
2. Fuel cells cannot be rebuilt; operators can trouble shoot a pneumatic pump, whereas a fuel cell is a “black box”.
3. Longevity of systems unknown.

A newer fuel cell technology will likely be released to the Canadian marketplace soon: a solid oxide fuel cell, which uses natural gas to create hydrogen instead of methanol. Until actual installations of this type of fuel cell occur, its potential cannot be evaluated, though packagers appear to view the technology as promising.

¹⁰ Trade name of common methanol based fuel cell system

HYBRID TEG SYSTEMS

A Thermal Electric Generator (TEG) is a solid-state device with no moving parts that converts heat to electrical energy via the thermal gradient from two different conductors; a solar chemical pump that uses a TEG as a supplemental power source for a typical solar chemical injection system is referred to as a Hybrid TEG system.

One of the basic challenges with TEGs is that they perform best when dealing with a constant base load electricity demand. The nature of a solar chemical injection system is that liquid is injected in a pulse; these pulsing demands do not match the constant output produced by a TEG. The addition of a TEG adds significant incremental cost to a solar chemical pump system, with incremental costs adding \$10,000 to \$30,000 per unit to the cost of an existing solar system.

The most notable example of a Hybrid Solar/TEG system was in the BP Noel tight gas development in British Columbia, heralded as a model for low-carbon development in Canadian northern latitudes. The project included 25 fully electric wellsites, with an initial plan for over 200 wellsites to be deployed. However, soon after the Noel field was commissioned, the assets were sold to Apache Canada Limited¹¹. The Pacific Carbon Trust and Blue Source Canada attempted to monetise the carbon value of the avoided methane to atmosphere of these systems, but data collected by Apache on injected chemical volumes was insufficient to support a successful verification.

Based on an analysis of Apache's annual vented volumes in the 2013 BC GHG Facilities report, it appears that these solar hybrid TEG systems may subsequently have been removed from service. Sirius Controls (which sold the solar component to BP) is of the view that these hybrid systems are still in place, but this has not been confirmed by Canadian Natural Resources, the current owner.

¹¹ <http://www.genthermglobalpower.com/case-studies/apache-noel-project>

GRID-TIED ELECTRIC CHEMICAL INJECTION

In cases where reliable power is available, electrically-driven chemical injection pumps are an option. Electrically-driven pumps have negligible capital cost differential relative to pneumatic alternatives (\$1,500 to \$2,000 for pneumatic; \$3,000 to \$4,000 for an electric) and lower operating cost given most reasonable assumptions of power prices (~\$200/year for electricity versus ~\$1000/year in lost natural gas).

At many remote sites, this is not a feasible option. One known case of the use of electrically-driven chemical injection pumps is the Dawson area. The project was envisioned as an add-on to an electrification project, with offsets purchased by the Pacific Carbon Trust and carried out with the expectation of revenue purchase of offsets by Pacific Carbon Trust to cover the costs of connection to the electric grid; however, Pacific Carbon Trust was cancelled before the purchase agreement for this project was completed.

OPERATIONAL EXPERIENCE

The most basic issue with a grid-tied electric pump system or remote generation system is the reliability of the power supply. In the case of gas-driven pneumatics, the supply is always available if the well is operating and there are no issues with the fuel gas system. In terms of remote locations, the distribution lines are often "radial" lines, which are less reliable than main transmission lines. In the case of a generation solution, if the generator goes down for maintenance it may create issues with the ability to control process or inject chemicals. Electric pumps supported by the grid or by self-generation require the necessary torque to overcome high pressures of current high-pressure wells.

An issue related to electric pumps and their field experience relates to operator familiarity with electric pumps. For example, the maintenance schedule on an electric pump is different from a pneumatic pump (lower

frequency) and different repair kits are required. Operator preference for familiar technology may create a barrier to project implementation.

SELF-GENERATION AND INSTRUMENT AIR

In cases where interconnection to the grid is too costly, does not meet the timing horizons for development, or where loads are too great to support other remote power solutions (solar, fuel cell, TEG), another alternative is to look at self-generation to either operate electrically-actuated valves and pumps or an instrument air system. The use of an instrument air system allows for reduced costs relative to electrically-actuated valves, and maintains the pneumatic pumps, thereby alleviating issues with regard to torque requirements.

GreenPath Energy examined a self-generation/instrument air configuration in the Kaybob area. The site had high fuel gas requirements from controllers and pumps. Initial wellhead pressures were exceeding 15,000 psi, stepped down to 2,500 psi, then 900 PSI. The project was a pilot project and not deployed at large scale; it is still uncertain

if the decline curves built into the gas consumption of the pumps have borne out. Initial projection of gas consumption for pumps and controllers were developed with a high case of 105 thousand cubic feet (Mcf) per day falling to 68 Mcf/day after five years. The generator, which provided power for the air compressor and ancillary services, required approximately 7 Mcf/day. The project had an average rate of return below 10% without a carbon value assigned, but reported very promising economics when a carbon value found in the Alberta Offset market was assigned to the project (>50%).

OPERATIONAL EXPERIENCE

The project was a pilot project, with promising initial results. One issue was that the generator set was over sized for the application as there was no generator set small enough for the role. Capital costs quoted included not only the cost of the generator, instrument air system (including filtering and drying), as well as a master control centre. The generator operated on field fuel gas with a high energy content, creating issues in terms of tuning the generator for the fuel content. Overall operator experience has been positive. The instrument air system operates standard pumps and controllers familiar for operators.

PUMP AND GHG INVENTORY

The number and location of gas-driven pumps in Western Canada is a figure with a large error bar on the projected total number of installations. An estimate undertaken by Cap-Op Energy for Alberta Innovates (Alberta Upstream Asset Inventory Study) suggested a population of 161,000 chemical injection pumps in Alberta based on interviews with subject matter experts and assigning pump population per asset type wellsites, batteries, and compressor stations. The Alberta Upstream Study asserts that less than 1% of pumps have been replaced with non-emitting alternatives.

There is no systematic data collection on gas-driven pumps in Alberta, nor any independent third party evaluation of the number of gas-driven pumps. However, data from the Reporting Regulation indicates that it may be possible to develop an estimate of the number of gas-driven pumps in BC.

Table 6: Pump Types in Prasino Study

TYPE	COUNT (% OF POPULATION)	EMISSION FACTOR (M ₃ /HR)
Piston	96 (53%)	0.5917
Diaphragm	85 (47%)	1.052

For 2013 (the last year for which data on emissions from chemical injection pumps in BC is available), reports indicated 261,000 tCO₂e from Chemical Injection Pumps (adjusting for the higher global warming potential of 25x vs 21 when initially reported).

Assumptions:

- 25 times global warming potential of methane in all cases
- Full year – Pump operates 8760 hrs/year – 95% methane in Fuel Gas
- 2/3 year – Pump operates 5840 hrs/year – 95% methane in fuel gas
- Max case – Pump operates 4380 hrs/year – 80% methane in fuel gas

Table 7: Potential pump population from BC Reporting Regulation data

PUMP TYPE	2/3 YEAR	FULL YEAR	MAX CASE
Piston	1752	1088	2944
Diaphragm	1602	1228	2270
Total	3354	2316	5215

There are roughly 10,000 operating gas wells in BC, and 300 operating batteries. While over 90% of these wells and facilities belong to operators with a reporting requirement under the BC Reporting Regulation, estimates of pump populations do not correlate well with the assumption of 1.0 pumps per well and 1.5 pumps per gas battery from the Alberta Upstream Asset Inventory. This bears several potential explanations:

1. BC Inventory of Pumps is incomplete due to:
 - a. Many operators with emissions less than 10,000tCO₂e/year; and/or
 - b. Incomplete inventories.
2. Ratio of wells/facilities to chemical injection pumps is inaccurate;
3. A large number of pneumatic pumps run on propane instead of fuel gas;
4. Gas driven alternatives are more common than understood.

It is unlikely that there are many operators not subject to the BC Reporting Regulation.

If an operator has one reasonable sized compressor (>1000 horsepower) and approximately 50 wells, reporting would be required. It is reasonable that the pneumatic estimates developed for the BC Reporting Regulation are incomplete or based on piping and instrumentation diagrams (P&ID) as opposed to field surveys.

The ratio of wells to facilities from the Alberta Upstream Asset Inventory may not be applicable to BC-based assets. An analysis of GreenPath’s data on pneumatic pumps shows a significant difference in ratio of pumps per facility between Alberta and BC, wherein BC has a higher ratio of pumps to facilities. This does not appear to be attributed to propane-driven pumps; based on expert opinion, approximately 2% of all gas-driven pumps run on propane. The most likely explanation is that pneumatic pump alternatives are more common than anticipated.

The number of SCPs installed in NE British Columbia is estimated based on interviews with chemical injection pump suppliers and producers with reporting requirements in BC.

Table 8: Solar Installs in Dawson / FSJ Area

Company A	>500		Company E	>50
Company B	322		Company F	1 (But 14 electric)
Company C	90		Company G	8 (electric)
Company D	~700*			

*Vendor claim with no supporting evidence from other vendors or operators.

Based on interviews and public data on companies with higher rates of pneumatic pump alternatives, potential offset revenue or a shadow price on carbon may be a factor in which companies have a higher rate of adoption for SCPs. Conservatively, over 1,000 solar chemical pumps have been deployed in British Columbia, which would suggest anywhere from 1/3 to 1/6 of all gas-driven pumps are non-emitting; accounting for non-emitting pumps, a maximum population of 6,000 can be achieved, at less than the 10,000 operating natural gas wells in BC. This suggests that a ratio of one pump per well is

not a reasonable proxy to determine the population of chemical injection pumps in BC. Analysis of GreenPath’s dataset shows a ratio of approximately 0.5 pumps per single-well battery and 0.3 pumps per multi-well battery.

A possible result is that inventories of companies with reporting regulation obligations misstated their inventories of pneumatic pumps. GreenPath has evaluated a number of these within the industry and have observed significant misclassifications and under-reporting.

CONCLUSIONS

A number of alternatives exist to gas-driven pneumatic pumps that are viable at northern latitudes and in colder climates. However, there is no one-size-fits-all solution to all pneumatic pump functions in upstream oil and gas operations.

Preliminary economics suggest that gas equivalent value of greater than \$6/GJ is required for industry to find an alternative viable. In the case of greenfield investments, the relative cost differential is minimal for alternatives (~\$7,000 for Solar Chemical systems, \$1,000-\$2,000 for electric pumps where power is available) relative to the total cost of a modern multi-stage hydraulically fractured unconventional well. In the case of retrofits, higher costs are incurred due to replacement of fittings and tanks as well as the installation and removal of the gas-driven system.

The economic evaluation is only one component of evaluating gas-driven alternatives. Other operational issues such as operator preference play into the decision whether or not to install an alternative to a gas-driven pump. Based the economic evaluation shown in Appendix A, and given that there is no carbon price signal currently for gas-driven pump alternatives, it is a non-economic (or difficult to economically evaluate) rationale for the installation of gas-driven pump alternatives.

Issues that appear to cause a preference for gas-driven pumps over low emitting alternatives such as:

- Ability to handle poor fuel gas quality;
- Reliability with sour gas;
- Ability to inject multiple chemicals at different rates; and/or
- Operator preference.

Chemical injection systems are a relatively low cost item relative to a modern multimillion-dollar multi-stage tight oil or tight gas well. The operational concerns managed by a chemical injection system and its operational costs and capital costs are minimal in comparison to the costs of downtime incurred by those concerns (such as hydrate formation, corrosion or other production issues). Therefore, reliability and operator preference are the most important aspects of an alternative to gas-driven chemical injection systems.

Conservatively, over 1,000 solar chemical pumps have been deployed in British Columbia, which would suggest anywhere from 1/3 to 1/6 of all chemical injection pumps are non-emitting. Further research is required to determine a more reasonable estimate of the number of gas-driven pneumatic pumps in Alberta and British Columbia, and from that, the potential methane emission reduction available from retrofits and changes to common practice.

GLOSSARY

ABSA

Alberta Boiler Safety Association

ALBERTA UPSTREAM ASSET INVENTORY STUDY

Study undertaken in 2013 by Cap-Op Energy on various pieces of methane emitting equipment in Alberta

AER

Alberta Energy Regulator; formerly the Energy Resources Conservation Board

BRITISH COLUMBIA REPORTING REGULATION

Greenhouse Gas Reporting Regulation under the Industrial Emission and Control Act, formerly under the Cap and Trade Act

BCGOC

British Columbia Oil and Gas Commission; a regulator for the Province of BC

CAPP

Canadian Association of Petroleum Producers

CAS

British Columbia Climate Action Secretariat; a branch of the Ministry of Environment

CCEMC

Climate Change and Emissions Management Corporation

CIP

Chemical injection pump; a pump that injects chemicals into a process in oil and gas operations; a subset of pneumatic pumps.

COP

ConocoPhillips Canada

CNRL

Canadian Natural Resources Limited

EDF/PEMBINA STUDY

A study conducted by ICF International on behalf of the Environmental Defense Fund and the Pembina Institute on methane abatement costs in Canada

<https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf>

GHG

Greenhouse Gas; all gases with a global warming effect as identified in the International Panel on Climate Change (IPCC)

PNEUMATIC PUMP

A pump using pneumatic pressure for motive force that may use fuel gas, instrument air, or propane.

PRASINO STUDY

Study undertaken by the Prasino Group in 2013 to review emission factors for the British Columbia Reporting Regulation.

SCP

Solar chemical pump. A chemical injection pump using solar panels and a battery to pump chemicals into a process.

VGC

Vent gas capture system; a system piloted by COP to capture vented gas from pneumatic pumps and combust in a Cata-Dyne heater.

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APPENDIX: PRELIMINARY ECONOMIC EVALUATIONS

To develop a consistent economic evaluation of the different technologies available, a common series of assumptions were chosen.

Where real installation costs were known, a common series of assumptions have been used to develop a consistent economic evaluation of the technologies available:

- Costs from the CCEMC energy efficiency project are used for Solar Chemical Pumps (Central Alberta) and vent gas capture systems, and vendor quotes.
- Greenfield costs assume only incremental costs (for example, costs of tank and fittings are excluded; the incremental greenfield cost includes solar panels, controller, and battery, less the cost of a pneumatic system)

To determine the required average gas price, the average natural gas price which results in a zero net present value given all other assumptions is calculated.

Table 9: Economic evaluation assumptions

ASSUMPTION	VALUE
Gas price	Sproule Station 2 – October 2015 forecast (less historical wellhead-Stn 2 spread of 1.08mmbtu)
Operating hours	8760 for corrosion Inhibitor, 5840 for methanol
Methane in fuel gas	90%
CO ₂ in fuel gas	2%
Global warming potential of methane	25 times CO ₂
Discount rate	17% ¹²
Baseline emissions	Prasino Study values unless otherwise stated
Useful life	10 Years

¹² <https://www.aer.ca/documents/sts/ST110/ST110-2012.pdf>

Table 10: Preliminary economic evaluation

INSTALLATION	CHEMICALS INJECTED	EQUIPMENT + INSTALLATION COST	VOLUME REDUCED (TCO2E)	REQUIRED GAS PRICE (\$/GJ)
Retrofit solar (Central AB)	Corrosion inhibitor	13,937	127*	8.20
Retrofit solar (Central AB)	Methanol	13,937	85*	12.20
Retrofit solar (Dawson Creek)	Corrosion inhibitor	16,200	127*	9.50
Retrofit solar (Dawson Creek)	Methanol	16,200	85*	14.14
Greenfield solar (Central AB)	Corrosion Inhibitor	7,470	127*	4.49
Greenfield solar (Central AB)	Methanol	7,470	85*	6.64
Greenfield solar (Dawson Creek)	Corrosion inhibitor	8,995	127*	5.37
Greenfield solar (Dawson Creek)	Methanol	8,995	85*	7.95
NON-SOLAR SYSTEMS				
Plainsman 510	Methanol	1,845	85*	1.79
Vent gas capture at wellsites	Methanol	6,500	85*	-
Methanol sphere (Small - Low Pressure)	Corrosion Inhibitor	3,800	40**	9.00
Methanol sphere (Large - higher pressure)	Methanol	7,705	66**	10.70
MULTIPLE SOURCE SYSTEMS				
Blair Air	Multiple	41,500	538**	5.83
Solar/TEG hybrid	Multiple	25,000	428**	7.13
Solar/fuel cell hybrid	Multiple	30,000	219**	12.80
Grid-tied multi-well pad	Multiple	75,000	2,773***	3.86
Calscan Bear 4	Multiple	37,000	514**	7.05
Calscan Bear 2	Multiple	26,000	351**	7.23
Instrument air multi-well	Multiple	250,000	9,929***	3.86

*2013 Prasino Study
 **Manufacturer Specifications
 *** Operational data



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