Methane Abatement Costs: Alberta

Alberta Energy Regulator

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DISCLAIMER

Acknowledgments

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EXECUTIVE SUMMARY

Methane mitigation in the upstream oil and gas sector is accomplished through a variety of mitigation options applied across a variety of point sources. In an effort to better categorize and track the costs associated with implementing methane mitigation technologies and work practices in the field, the Alberta Energy Regulator commissioned this study to examine the range of costs associated with each of the options. As a first step, publicly available information was compiled from a variety of US and Canadian sources to provide an indication of the level of detail that is available and inform the development of cost estimates that better represent the actual costs that are experienced in the field in Alberta. The cost estimates are based on a combination of data sources and often rely on publicly available data as well as data and information provided by subject matter experts, technology vendors, service companies and oil and gas companies. Summary tables of the aggregated costs for each of the methane mitigation option categories is provided below with detailed information on methodology, assumptions and references included in the body of the report. Costs in this report are assumed to be the typical average cost across a fleet or company. It is recognized that costs could range significantly on each individual scenario and there is an expectation that realized costs will differ between companies, locations and facilities. Each cost estimate provided in this report is a generalized estimate based on available information collected at the time of publication and not all cost circumstances will be represented in the values described in this report.

Leak Detection and Repair (LDAR)

Internal LDAR - Average Costs						
Facility Type	Labour Cost Per Survey	Repairs (annual)	Inventory/ Reporting Cost (per survey)	Total Amount - IF 4X per Year, per Location	Total Amount, per survey (w repairs)	Total Amount, per survey (no repairs)
Wells	$ 514	$ 1,541	$ 143	$ 4,166	$ 1,041	$ 656
Batteries	$ 1,027	$ 3,082	$ 285	$ 8,332	$ 2,083	$ 1,313
Compressor Stations	$ 2,054	$ 6,163	$ 571	$ 16,663	$ 4,166	$ 2,625
Gas Gathering Systems	$ 2,054	$ 6,163	$ 571	$ 16,663	$ 4,166	$ 2,625
Gas Plants	$ 3,072	$ 9,216	$ 853	$ 24,917	$ 6,229	$ 3,925
3rd Party LDAR - Average Costs						
Facility Type	Labour Cost Per Survey	Repairs (annual)	Inventory/ Reporting Cost (per survey)	Total Amount - IF 4X per Year, per Location	Total Amount, per survey (w repairs)	Total Amount, per survey (no repairs)
Wells	$ 1,035	$ 3,105	$ 64	$ 7,500	$ 1,875	$ 1,099
Batteries	$ 1,746	$ 5,239	$ 124	$ 12,718	$ 3,180	$ 1,870
Compressor Stations	$ 3,042	$ 9,126	$ 233	$ 22,225	$ 5,556	$ 3,275
Gas Gathering Systems	$ 3,662	$ 10,985	$ 249	$ 26,629	$ 6,657	$ 3,911
Gas Plants	$ 4,788	$ 14,365	$ 333	$ 34,848	$ 8,712	$ 5,121

Pneumatic Devices

Summary Table Mitigation Option	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Replace High-Bleed Devices with Low-Bleed Devices High Cost Range	$ -	$ -	$ 2,090	$ -
Replace High-Bleed Devices with Low-Bleed Devices Low Range	$ -	$ -	$ 1,241	$ -
Replace High-Bleed Devices by Installing Retrofit Kits High Cost Range	$ -	$ -	$ 1,147	$ -
Replace High-Bleed Devices by Installing Retrofit Kits Low Range	$ -	$ -	$ 310	$ -
Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps High	$ -	$ -	$ 13,603	$ -
Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps Low	$ -	$ -	$ 9,608	$ -
Electrification of Pneumatic Devices High Cost Range	$ 25,000	$ 117	$ 45,500	$ 117
Electrification of Pneumatic Devices Low Cost Range	$ 20,000	$ 117	$ 22,500	$ 117
Instrument Air w/SOFC	$ 54,370	$ 3,000	$ 61,784	$ 3,000
Instrument Air w/ TEG	$ 21,370	$ 50	$ 24,284	$ 50
Instrument Air w/ Grid (3km)	$ 65,370	$ -	$ 74,284	$ -
Instrument Air w/ Solar	$ 20,000	$ 117	$ 35,000	$ 117
Vent Gas Capture to Small Combustor (5000 scf/d)	$ 16,500	$ -	$ 21,000	$ -
Vent Gas Capture to Large Combustor (1.75 Mscf/d)	$ 49,500	$ -	$ 63,000	$ -
Vent Gas Capture to Catalytic Heaters	$ 5,000	$ -	$ 6,000	$ -

Compressors and Engines

Summary Table Mitigation Option	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Conversion of Gas Starter to Air Start	$ 235,836	$ 1,500	$ 293,916	$ 5,000
Starter Vent to Flare - Tie to Existing Flare Stack	$ 3,025	$ 150	$ 12,100	$ 150
Starter Vent to Flare - Tie to New Combustor	$ 51,425	$ 650	$ 60,500	$ 650
VRU Vent Capture to Inlet	$ 284,350	$ 5,000	$ 447,700	$ 5,000
Capture Packing Vents & Convey to Existing Flare	$ 45,980	$ 5,000	$ 182,710	$ 5,000
Capture Packing Vents & Convey to New Combustor	$ 94,380	$ 5,500	$ 231,110	$ 5,500
Capture Packing Vents & Convey to Existing Flare-No Vacuum	$ 18,150	$ -	$ 76,230	$ -
Capture Packing Vents to New Combustor-No Vacuum	$ 66,550	$ 500	$ 124,630	$ 500
Capture Blow Down to Inlet	$ 3,630	$ -	$ 12,100	$ -
Capture Blow Down to Inlet - Add a combustor	$ 52,030	$ 500	$ 60,500	$ 500
Capture atmospheric vents with SlipStream® SS3 standalone and convey to engine air inlet to blend with fuel gas	$ 27,500	$ 800	$ 52,250	$ 800
Capture atmospheric vents with SlipStream® SS10 standalone and convey to engine air inlet to blend with fuel gas	$ 37,400	$ 800	$ 61,050	$ 800
Capture atmospheric vents with SlipStream® SS10 in existing REMVue AFR and convey to engine air inlet to blend with fuel gas	$ 33,000	$ 800	$ 57,750	$ 800
Packing Rebuild to OEM Standard	$ -	$ -	$ 25,000	$ 6,250
Packing Upgrade to Low Bleed Packings	$ 3,000	$ -	$ 25,000	$ 6,250
Packing Build - Shutdown Seal	$ 15,000	$ 1,500	$ 35,000	$ 7,750
Centrifugal Seal Build - Dry Seal	$ -	$ -	$ 60,500	$ 5,000
Centrifugal Seal Build - Wet Gas Seal	$ -	$ -	$ 84,700	$ 6,000
Centrifugal Seal Build - Convert Wet Seal to Dry Seal	$ -	$ -	$ 1,452,000	$ 5,000
Meters - Low Flow Turbine with Flow Computer and Logger	$ 15,730	$ 500	$ 24,200	$ 1,000
Meters - Thermal Mass Flow Meter High Cost Range	$ 27,830	$ 500	$ 36,300	$ 1,000
Meters - Thermal Mass Flow Meter Low Cost Range	$ 10,890	$ 1,500	$ 19,360	$ 2,000
Meters - Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation	$ 605	$ -	$ 3,630	$ 500
Meters - Periodic Measurement with Thermal Mass Flow	$ 605	$ -	$ 3,630	$ 7,500

Dehydrators

Summary Table / Mitigation Option	CAPEX - High Range	CAPEX - Low Range	Annual Maintenance
Install Flash Tank Separators on Dehydrators and Route Gas to Compressor, Reboiler, or Sales	$ 50,835	$ 13,139	$ -
Optimize Glycol Circulation Rates in Dehydrators	$ -	$ -	$ 540
Replace Gas Powered Glycol Pumps with Electric Glycol Pumps	$ 35,429	$ 13,880	$ -
Glycol Dehydrator Optimization	$ 199,273	$ 8,134	$ -
Stripping Gas Elimination	$ -	$ -	$ 500

Oil and Gas Site Venting

Summary Table / Mitigation Option	CAPEX - High Range	CAPEX - Low Range	OPEX - High Range	OPEX - Low Range
Plunger Lift Instead of Well Venting for Liquids Unloading	$ 16,200	$ 4,050	$ 1,300	$ 700
Reduce Liquids Unloading Venting - Flaring/Incineration/Destruction Device	$ 48,700	$ 46,700	$ -	$ -
Install Vapour Recovery Units on Storage Tanks	$ 185,078	$ 47,711	$ 16,839	$ 7,367
Recover Casing Vent and Use as Fuel, For Power Generation, connect to VRU	$ -	$ 6,166	$ -	$ -
Casing Gas Recovery Compressors (CHOPS)	$ 203,340	$ 41,685	$ 6,400	$ 5,000
Casing Gas Combustor/Incinerator (CHOPS)	$ 116,921	$ 76,253	$ 1,000	$ 277

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1 Introduction

One of the four key pillars in the Alberta Climate Leadership Plan includes developing a new methane emission reduction plan. As the single regulator for energy development in Alberta, the Alberta Energy Regulator (AER) is working collaboratively to develop and implement an efficient and effective regulatory framework that achieves the Government of Alberta's methane emissions reduction outcome of a 45 per cent reduction in venting from the 2014 BAU by 2025.

A key component and data point needed to design a cost effective and operationally feasible regulatory framework is a range of methane abatement costs in Alberta. To create an Alberta specific understanding and summary of methane abatement costs in the upstream oil and gas sector in Alberta, the AER contracted The Delphi Group, a Canadian strategic consultancy providing innovative solutions in the areas of climate change and corporate sustainability, to gather information from previous projects, literature, and directly from operators and vendors. The goal of the project is to summarize the range of costs that are currently experienced in the sector for the majority of methane abatement activities that occur, or are expected to occur, in Alberta. While cost studies for methane abatement projects have been conducted in other jurisdictions, the costs experienced in Alberta often vary considerably from these reported costs and there is a need to refine the assumptions and sources of information to align with an Alberta context.

While there are costs that can impact the overall project economic calculations for each individual option, the focus of this effort was to summarize and provide detailed cost estimates for the capital and non-energy operating costs (CAPEX and OPEX) for each of the options. This study does not include an analysis of the avoided costs or specific costs associated with energy related costs savings that are achieved through each of the emission reduction projects. The focus is to specifically estimate the average upfront CAPEX expenditures for each option as well as average OPEX changes due to maintenance requirements or component replacement. The exclusion of energy related OPEX changes is to incorporate updated vent rate estimates, power consumption requirements and fuel gas savings estimates that are being compiled through other ongoing projects that the AER is conducting. The combination of this study and the other studies will become inputs into the AER's overall regulatory development process and modelling efforts and together they will provide a comprehensive picture of undertaking methane abatement activities in Alberta.

2 Overview of Approach, Assumptions, and Limitations

2.1 Approach

The process of collecting and analyzing Alberta specific cost information for methane abatement technologies and practices included several steps and information gathering efforts in order to ensure the most representative values are being reported. The availability of cost information from other jurisdictions, primarily the US, provided a starting point from which to base the analysis and supplement/aggregate data from other sources. Where possible, Alberta specific information was referenced which included Climate Change and Emissions Management Corporation (CCEMC[1]) project summaries and presentation[2], presentations and project reports from the Petroleum Technology Alliance of Canada (PTAC), among others. US EPA Gas Star analysis was incorporated and reviewed and used to fill in areas where there is not sufficient Canadian specific data coverage. Inflation and exchange rates were considered for non-Canadian estimates. A complete desktop review of other reports that quantify the costs of methane abatement technologies was completed and incorporated into the analysis.

Once all background information and existing data sets were categorized, Delphi tested the costs and assumptions with industry and service providers and compared internal documentation that was provided confidentially with published values. The AER also convened multi-stakeholder technical and subject matter expert working groups that provided cost inputs and data from their experiences implementing these projects in Alberta. Through several meetings with the working groups and direct contact with service providers, Delphi aggregated information where possible to create assumptions and cost values that best represent the current cost environment for completing methane reduction projects in Alberta.

2.1.1 AER Technical and Subject Matter Expert Committees

As a part of the regulatory stakeholder engagement efforts, the AER convened several committees to ensure all stakeholder perspectives and Alberta specific expertise was properly considered and incorporated. The Methane Oversight Committee, the primary decision-making committee which was tasked with making final recommendations to the AER, convened the Measurement Monitoring and Reporting Technical Committee, the Methane Reduction Technical Committee and the Methane Focus Group. Subject Matter Expert (SME) Committees were also convened for venting, pneumatic devices and compressors. These committees were tasked with providing additional data to the AER to help understand the details of all aspects of methane abatement options in the province and to recommend the technical and regulatory content of the proposed methane reduction regulatory framework

[1] Now Emissions Reduction Alberta (ERA)
[2] For example: http://cetacwest.com/eco-efficiency/energy-efficiency-and-energy-management-workshops/2015-cpc

(including license approvals, directives, compliance assurance programs and measurement / performance requirements) for both new and existing facilities.

These committees met on a regular basis and contributed data, expertise and advice to the regulatory development process including information on costs. The Delphi Group met with these committees to review all cost data from other sources and to fill in gaps in the cost information with additional data from multiple stakeholder groups including equipment vendors, installers, producers and technology providers who have intimate working knowledge of the current state of methane abatement costs in Alberta.

Where possible, direct data (documents) was obtained from service providers and producers and supplemented with other information obtained from studies. In some cases, where direct data was not available, the SME committee members provided consensus agreement on representative calculations for assumptions that could be used to fill in all the data points needed to estimate costs for certain equipment types.

2.2 Assumptions and Limitations

2.2.1 Assumptions

While every effort was taken to source data from example projects and activities that have happened in Alberta, there are several technologies and practices that have either not been deployed or have limited trials in an Alberta context. There are also site and regional variations in the cost of implementing or conducting projects that influence the overall cost of options due to travel time, remoteness of sites or different operating characteristics that would require additional equipment, time or people power to properly implement the methane abatement activities. The variability in these sites was taken into consideration and incorporated into the ranges of costs where feasible, however assumptions were used where necessary. Detailed technology specific assumptions are provided in each of the sections below and, where possible, all cost inputs are referenced to the data source or organizations that were consulted in the development of the cost assumptions. Standard overall assumptions used throughout the activities are detailed in Table 1. Brokerage and shipping & handling costs are included in cost estimates where Canadian data was available but are not factored into any additional assumptions for the US specific data.

Table 1 - General Assumptions

Assumption	Value	Units	Source	
Inflation and Currency Conversion				
Exchange Rate	1.32	CAD/USD	2016 US Canada Average exchange rate	http://www.canadianforex.ca/forex-tools/historical-rate-tools/yearly-average-rates
Inflation Rate	1.67%	average annual %	2005-2015 average annual inflation rate	http://www.inflation.eu/inflation-rates/canada/historic-inflation/cpi-inflation-canada.aspx

2.2.2 Limitations

As with any cost estimates, there is an inherent limitation in the ability to predict and anticipate all potential circumstances that would have an impact on the cost of an individual project. This study attempts to provide cost ranges that include considerations for the different types of field sites locations, labour rates and equipment types that may be experienced by operators. The rate sheets that were provided to Delphi are a representation of the labour rates at a specific period of time in the industry that has seen a depression in labour rates due to less industry activity as a result of global market factors. Changes to the supply or demand in this sector will have an impact on labour availability and will influence the directional change in labour rates going forward.

This report is also not intended to, and does not, account for scalability of different deployment scenarios in the sector. As with any technology adoption and deployment curve, significant efficiencies can be gained by planning and structuring the roll-out of a comprehensive methane abatement plan at a company or in a specific region. There are potential opportunities for producers to collaborate based on regional and facility type similarities and reduce costs through economies of scale both in the purchasing of equipment as well as installation costs. Costs are expected to decrease over time as more deployment occurs as well as emerging technologies enter the market.

Several considerations for emerging technologies should be addressed in future analysis of the overall cost to the sector and factored into long-term reduction strategies at producers. There is emerging potential for growth opportunities for methane abatement service companies in Alberta and funding available to support development and commercialization of these technologies as evidenced by the recent funding focus on emerging methane reduction technologies through ERA [3] as well as US based ARPA-E funded companies [4] that are nearing commercialization. With market opportunities beyond Alberta for service companies that focus on methane reduction in the oil and gas, it is likely that there will be an accelerated commercialization cycle and increased competition among businesses that develop, manufacture, or deploy commercial technologies that help reduce methane emissions across the spectrum of industry needs.

[3] http://eralberta.ca/apply/
[4]https://arpa-e.energy.gov/?q=news-item/monitor-project-teams-develop-innovative-methane-detection-technologies

3 Leak Detection and Repair (LDAR)

There are several options available to producers to conduct leak detection and repair (LDAR) at oil and gas sites and various technologies that can be used for this type of assessment. The technologies range in functionality and cost depending on the intended objective of the survey. Detection technologies primarily rely on the ability to identify the presence of methane in a specific area and then refine the search to identify the specific location where the leak is occurring. Additional steps and technology types can then be used to quantify the volume of methane gas that is being emitted to the atmosphere. Several technological advancements have recently become available that combine the ability to detect and quantify the methane leaks in one step. There are also many technologies in development and being tested in the field[5] that are attempting to drastically change the way that LDAR data and procedure occur and may have significant impacts on the costs of conducting a LDAR program in the field.

The existing detection technologies that are primarily used and that have reliable cost data employ forward looking infra red (FLIR) cameras. These cameras are generally handheld and provide a trained technician with a visual representation of the methane leak plume while providing necessary guidance to track down the source of leaks in the field. For standard detection surveys, costs are impacted by the facility type that is being surveyed, the type of equipment that is used, the speed at which the survey can be completed effectively and the mobilization costs involved with getting trained personnel to the survey sites. The second step of quantification of the leaks, while a requirement for certain types of leaks (e.g., surface casing vent flows (SCVF)), is not currently required by regulations and not all companies conduct quantification of the leak volumes or rates as a part of their LDAR programs. This is relevant to the cost data that was considered for this study as there is quite a bit less information available on the field costs of conducting a detailed detection and full quantification for all surveys. While the costs estimates provided account for some quantification time and equipment, the data was less robust and there is a greater degree of uncertainty on the actual costs of quantification in the Alberta oil and gas facilities.

There are generally two options available to operators for conducting a LDAR program, and there are different cost and operational considerations associated with each option. The first option allows oil and gas companies to internalize the LDAR program (internal LDAR program), purchase the equipment and train internal staff to conduct the LDAR programs on their own sites. The second option is to hire a third-party service provider to conduct a site survey and identify methane leaks. There are benefits and drawbacks with each option and decisions will need to be evaluated on an individual company basis. Typical considerations for oil and gas companies include the size of the facility inventory that is expected to be monitored and the investment in equipment and training that is required in

[5] Technologies under development include: UAV, satellite, remote sensing, computational modeling, etc. that are being developed around the globe. There are also several funding programs through the Emission Reduction Alberta (ERA) and Alberta Innovates that may fund pre-commercial LDAR technologies that should drive down the cost and increase the performance of current LDAR programs.

order to conduct an internal LDAR program vs. cost sharing this expertise across multiple operating oil and gas companies through the use of a third-party LDAR service provider.

3.1 Internal LDAR Program

Companies that choose to internalize LDAR programs can achieve some benefits associated with efficiently training onsite staff and reducing travel and set-up costs. Having internal staff trained on the detection and repair of leaks can speed up repair timeframes by having licenced field staff conduct the repairs immediately following the identification and tagging of the leaks.

The cost data for internal LDAR programs is based on several different information and data sources. While individual operators were engaged as a part of the AER's technical and subject matter working groups, detailed invoices and cost analysis was not available to separate out the full costs of an Alberta based internal LDAR program. The cost estimates are therefore based on information that was compiled by ICF as a part of their 2015 economic analysis of methane emission reduction opportunities report[6] and supplemented with data and information provided by Canadian operators through the AER technical working group. The data compiled by ICF provides an estimate of the amortised cost of equipment and employee training and labour that is required to conduct and implement an internal LDAR project. The hourly labour rate estimate includes the following components: A capital cost of $245.5k which includes $183.3k for infrared camera; $7.5k for photo ionization detector; $33k for truck; $21.75k for reporting system and; $12.45k for training (one-off). The annual labour is $292.5k/year for dedicated staff time and benefits. The hourly rate is calculated from these values where the amortized capital over 5 years and annual labour costs are assumed at 1,880 hours/year. This calculation results in an hourly labour rate of $192. With this hourly cost estimate, several other assumptions and additions have been layered onto the analysis based on data received by producers and in consultation with the AER LDAR Technical Committee. Estimates for the time requirements for conducting a survey at various facility types were broken out and an additional inventory/reporting cost was added to account for additional time required to report and track the inventory of leaks and repairs. The inventory costs are estimated to take 50% of the time it took to complete the survey and are charged at a lower rate as this is typically conducted by more junior or office staff that can be resourced across the company. Repair cost estimates are based on assumed costs that, on average, tend to be in the range of 3 times the cost of one survey over the course of a year. This is an assumption that was verified and deemed to be an adequate representation of the average repair costs experienced by producers in Alberta.

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[6] ICF International. (September 2015). 2015 Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries. Available online: https://www.edf.org/sites/default/files/content/canada_methane_cost_curve_report.pdf

Table 2 Internal LDAR Costs by Facility Type

Internal LDAR - Average Costs						
Facility Type	Hourly Labour Rate	Labour Cost Per Survey	Repairs (annual)	Inventory/ Reporting Cost (per survey)	Estimated Time for each Survey - Avg (hr)	Total Amount - IF 4X per Year, per Location
Wells	$ 192	$ 514	$ 1,541	$ 143	2.7	$ 4,166
Batteries	$ 192	$ 1,027	$ 3,082	$ 285	5.4	$ 8,332
Compressor Stations	$ 192	$ 2,054	$ 6,163	$ 571	10.7	$ 16,663
Gas Gathering Systems	$ 192	$ 2,054	$ 6,163	$ 571	10.7	$ 16,663
Gas Plants	$ 192	$ 3,072	$ 9,216	$ 853	16.0	$ 24,917

Reported survey times for internal LDAR programs varied between operators and could be drastically different based on the facility type, vintage, experience of the internal staff among other things. As such, the estimates for survey times were developed through discussions with the AER Technical Committee members. It was determined that a good reference point for survey times was the more reliable third-party data that was available. Once checked against internal survey times, it was determined that, for the purposes of providing estimates for each of the facility types, it is a reasonable assumption that the survey times for internal LDAR surveys are similar to the survey times required by third-party providers.

3.2 Third-party LDAR Program

A third-party LDAR program would rely on outside expert service providers to perform the detection and identification of leaks at a site and depending on the company and type of site, repairs could be conducted by either the third-party LDAR technician[7] or site operators. Coordinating these efforts and efficiently conducting repairs is a necessary additional planning component that will contribute to the methane reduction effectiveness and cost efficiency of a third-party LDAR program.

The costs compiled for third-party LDAR services are based on confidential rate sheets from several LDAR service companies that provided day rates, estimates of time needed to conduct the surveys, travel time and additional equipment costs. These day rates and equipment rental costs were aggregated and compiled to provide an appropriate representation of an average cost breakdown of conducting third-party surveys at different facility types. While there was generally very good alignment between the quoted survey times for different facility types,

[7] Some LDAR service providers have the necessary training and tickets to perform minor leak repairs while they conduct the survey, while others simply tag the identified leaks and rely on operators to fix the leaks. This introduces some variability in the costs depending on the option that is chosen but is small in terms of the rate differential and time requirements so it has been excluded from this analysis.

the day rates and included items did vary between service providers. In all instances, the day rates represented in Table 3 includes the technologist time, cost of a service truck, cost of the detection and basic quantification equipment and any additional support equipment required to perform general LDAR site surveys.

Table 3 Third-party LDAR Costs by Facility Type

3rd Party LDAR - Average Costs							
Facility Type	Hourly Labour Rate	Labour Cost Per Survey	Repairs (annual)	Inventory/ Reporting Cost (per survey)	Travel Time Between Sites	Estimated Time for each Survey - Avg	Total Amount - IF 4X per Year, per Location
Wells	$ 282	$ 1,035	$ 3,105	$ 64	1.0	2.7	$ 7,500
Batteries	$ 282	$ 1,746	$ 5,239	$ 124	1.0	5.2	$ 12,718
Compressor Stations	$ 282	$ 3,042	$ 9,126	$ 233	1.0	9.8	$ 22,225
Gas Gathering Systems	$ 282	$ 3,662	$ 10,985	$ 249	2.5	10.5	$ 26,629
Gas Plants	$ 282	$ 4,788	$ 14,365	$ 333	3.0	14.0	$ 34,848

*Mobilization costs variable depending on location.

One of the major areas of uncertainty when calculating the costs for a third-party LDAR study, is the mobilization costs required to initially transport a LDAR crew to the sites. Depending on the location within the province, there can be a large upfront cost to initiate the surveys in the region. This is where efficiently planning for surveys is crucial. Opportunities exist for producers in one area to better coordinate services, mobilize crews and cover regions at once across multiple producing companies. Doing so minimizes mobilization costs and travel time between sites. Reported mobilization costs varied between LDAR service providers and may be charged on a per kilometer basis($1/km) or on an hourly basis(~$130/hr).

Additional LDAR costs can be incurred depending on the type of detection and quantification that is needed or preferred. An example of the potential additional rental costs for technologies not included as a part of 'typical' detection and quantification services is provided in Table 4. It demonstrates the potential range of auxiliary equipment that may be required for completing specific quantification tasks.

Table 4 Example Auxiliary Equipment Costs

Example Auxiliary Equipment	
Equipment Item	**12 hr day rate**
Ultrasonic Leak Probe	$275/day
High/Low Flow Sampler	$175 - $250/day
Photoionization Detector	$150/day
SCVF Positive Displacement Meter	$300/day

These costs are generalized from several LDAR service providers and while each provider used their own combination of testing equipment and procedures, the performance and reliability of each system was not evaluated for this study. The inventory and reporting services offered by third-party service providers also removes complexity and the need for additional training and staff to coordinate the tracking and management of the LDAR program. Reported costs for the internal LDAR programs are higher than those quoted by third-party LDAR service providers and can be attributed to the ability for third-party provider so share the costs of their software packages and staff time across customers.

The decision to hire a third-party LDAR service provider s dependent on several key considerations and will differ greatly between producers. Costs will continue to factor into the decision to internalize a LDAR program by producing companies in Alberta. Third-party providers offer expert and highly trained personnel that can conduct the surveys efficiently and remain cost competitive with internal programs given the level of complexity and the information that needs to be managed.

4 Pneumatic Devices

Pneumatic devices in an upstream oil and gas application refers to any controller, pump, instrument or other equipment that operates based on an energy input from a compressible working fluid. In conventional oil and gas applications, this working fluid has generally been produced natural gas (primarily methane), propane or air. In most instances, the working fluid that was used to perform the action is vented to atmosphere. The ability to reduce the amount of methane vented and conserve the gas in the pipeline system is an opportunity for technology to either retrofit existing devices or replace devices with electric controls.

Data for pneumatic devices was initially obtained through publicly available reports that were submitted to CCEMC and other joint industry presentations and reports that provide details on field experiences working on replacing or retrofitting pneumatic devices. While these costs represent actual costs that were experienced in the Alberta field context, they are limited in terms of the types of technologies and available makes and models of equipment. The summary of the results from the initial scan of publicly available cost data for Alberta pneumatic device replacements is provided in Section 8.2 in the Appendix.

The results of the initial scan of publicly available costs for pneumatic device mitigation options was used as a reference point to inform further engagement with the Technical and SME committees. Through these working groups, additional data was provided by vendors with estimates of labour and equipment costs, time to complete replacements and other available retrofit and replacement options that are available on the market. Based on several inputs provided by equipment vendors, further estimates were generated to reflect the average costs of several options to reduce methane venting from pneumatic devices.

A summary of the average costs modeled for pneumatic devices is included below in Table 5.

Table 5 Pneumatic Device Mitigation Option Summary Cost Table

Summary Table Mitigation Option	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Replace High-Bleed Devices with Low-Bleed Devices High Cost Range	$ -	$ -	$ 2,090	$ -
Replace High-Bleed Devices with Low-Bleed Devices Low Range	$ -	$ -	$ 1,241	$ -
Replace High-Bleed Devices by Installing Retrofit Kits High Cost Range	$ -	$ -	$ 1,147	$ -
Replace High-Bleed Devices by Installing Retrofit Kits Low Range	$ -	$ -	$ 310	$ -
Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps High	$ -	$ -	$ 13,603	$ -
Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps Low	$ -	$ -	$ 9,608	$ -
Electrification of Pneumatic Devices High Cost Range	$ 25,000	$ 117	$ 45,500	$ 117
Electrification of Pneumatic Devices Low Cost Range	$ 20,000	$ 117	$ 22,500	$ 117
Instrument Air w/SOFC	$ 54,370	$ 6,000	$ 61,784	$ 6,000
Instrument Air w/ TEG	$ 21,370	$ 50	$ 24,284	$ 50
Instrument Air w/ Grid (3km)	$ 65,370	$ -	$ 74,284	$ -
Instrument Air w/ Solar	$ 20,000	$ 117	$ 35,000	$ 117
Vent Gas Capture to Small Combustor (5000 scf/d)	$ 16,500	$ -	$ 21,000	$ -
Vent Gas Capture to Large Combustor (1.75 Mscf/d)	$ 49,500	$ -	$ 63,000	$ -
Vent Gas Capture to Catalytic Heaters	$ 5,000	$ -	$ 6,000	$ -

4.1 Technology Options

Several technology types fit within the category of pneumatic devices and while data was collected on specific makes and models of equipment options from several technology vendors, the options have been categorized here in order to maintain confidentiality between competitors. Make a model specific information in the public domain is included if relevant to the category of technology. The costs have been generated using estimates for labour, material, trucks and logistics timing that was vetted and discussed with several equipment vendors and oil and gas companies. The list of mitigation technology includes:

- Replace High-Bleed Devices with Low-Bleed Devices
- Replace High-Bleed Devices by Installing Retrofit Kits
- Replace Pneumatic Pumps with Electric Pumps or Low/No-Bleed Pumps
- Electrification of Pneumatic Devices
- Replace Gas System with Instrument Air System for Pneumatic Devices
- Vent Gas Capture to Combustion

Each one of these technology options includes several potential technology opportunities or equipment options. Costs for every option available was not collected through this study, but a representative average cost is provided in the subsequent sections.

For most pneumatic device management programs, an essential step is creating an inventory of the existing devices and an inventory of the replaced devices. Tracking and categorizing pneumatic inventories effectively provides needed information used to decide which mitigation option(s) provide the optimized methane reductions at the lowest cost available. Inventory costs can range depending on who is conducting the inventory, the type of site, the location and distance between sites and software or documentation that is prepared. Modeled costs for conducting an inventory are shown in Table 6.

Table 6 Pneumatic Inventory Costs

Activity	Devices per day	Labour	Truck	Material	Total per Device	Assumptions
Inventory	8	$82	$32	$12	**$127**	- 8 inventories per day - 3 – 6 devices per site - Using preconfigured software - Single well site is one inventory - Permitted access for long term without operations

4.1.1 Operating Costs

In addition to the initial capital cost associated with installing mitigation options, some options include incremental operational (OPEX) costs that need to be considered to understand the difference in cost between existing equipment and the lower emitting options. While this report does not quantify any energy related operational costs implications that occur as a result of implementing the abatement options, differences in operational costs are captured where they apply. This includes differences in maintenance requirements, equipment, calibration or other ongoing costs that may be different than what would be experienced in the standard or BAU option. In several instances, the operational costs are, on average, very similar to existing equipment and therefore there is no OPEX cost considered.

4.2 Replace High Bleed with Low Bleed Devices

This option refers to the replacement of existing high bleed pneumatic instruments with alternative low bleed pneumatic instruments. Challenges with this option can be the low vented gas volumes at most sites and large distances between sites, which leads to higher installation (labour) costs. Actual gas savings may not reflect the manufacturer specifications. Manufacturer published values are conservatively high to ensure adequate pneumatic supply is available, but this also means that gas savings are often lower. These reductions can be applied to positioners, pressure controllers, level controllers and transducers.

Table 7 High to Low Bleed Device Replacement Costs

Mitigation Technology	CAPEX (CAD 2016)		Assumptions	References
Replace High-Bleed Devices with Low-Bleed Devices	High Cost Range	$2,090	High cost is an average cost from 1062 installations. Includes several types of retrofits including high bleed transducers and pressure controller replacements with new low bleed instruments.	ConocoPhillips CCEMC Project Workshop http://cetacwest.com/eco-efficiency/energy-efficiency-and-energy-management-workshops/2015-cpc
	Low Range	$1,241	Costs to replace high bleed level controllers with low/no bleed model including install cost. Inventories are assumed to be completed prior to	AER SME committee provided data.

			install. Inventories allow for ordering exact replacements. Process can be shut down or bypassed during install by installer and restarted.	

4.3 Replace High Bleed Devices with Retrofit Kits

Certain high-bleed pneumatic devices have the option to install a retrofit kit to lower vent rates. The retrofit option that was used as a reference point to provide cost ranges is the retrofitting of model 4150 pressure controllers with Mizer kits which is an aftermarket kit. Additional costs were modeled for several other retrofit options including high bleed to low bleed transducers and level controllers.

Table 8 Retrofit Kit Costs

Mitigation Technology	CAPEX (CAD 2016)		Assumptions	References
Replace High-Bleed Devices by Installing Retrofit Kits	High Cost Range	$1,147	Based on 110 retrofits of model 4150 pressure controllers with Mizer Kits (after-market retrofit kit). Costs include travel, labour and component costs.	Callendar Energy Services.
	Low Range	$310	Average of costs for high bleed to low bleed transducer and level controller retrofit kits. Inventories are assumed to be completed prior to install. Inventories allow for ordering exact replacements. Process can be shut down or bypassed	AER SME committee provided data.

			during install by installer and restarted.	

4.4 Replace Pneumatic Pumps with Electric or Low/No-Bleed Pumps

Replacement of high bleed pumps with low bleed pumps or electric pumps reduces methane emissions and can be a cost-effective way to mitigate methane in the correct situation. This option most widely applies to chemical injection pumps at well sites and is the primary source of data that was available at the time of this study. In general, the primary option to convert well sites from gas pneumatic pumps to electric pumps that had reliable cost data was through the application of a solar electric pump. The cost of solar electric pumps (including solar panels, batteries, the pump itself and other equipment) is the biggest barrier to implementation (cost may be 5 times greater than the equivalent pneumatic pump). Battery life and solar resource in northern climates may limit the applicability of solar pumps.

Table 9 Cost of Pneumatic Pump Replacements

Mitigation Technology	CAPEX (CAD 2016)		Assumptions	References
Replace Pneumatic Pumps with Electric Pumps or Low/No-Bleed Pumps	High Cost Range	$13,603	High end of the range is based on ConocoPhillips CCEMC project, which included installation of 86 solar chemical injection pumps.	ConocoPhillips CCEMC Project Workshop (Dec 2015).
	Low Range	$9,608	Low end of range based on 138 solar pump installations in south-central Alberta. Includes a mix of single pumps and dual-headed pumps. CAPEX includes installation costs.	ConocoPhillips CCEMC Project Workshop (Dec 2015).

4.5 Electrification of Pneumatic Devices

Many small well sites are typically controlled with pneumatic devices. In specific circumstances, these sites can be retrofit or new sites can incorporate a solar-electric system including electric control panel, solar panels, batteries, electric chemical injection pump, electric controllers and electric actuators.

Table 10 Electrification of Pneumatic Devices at Well Sites

Application	Installed Retrofit CAPEX ($)	Installed Greenfield CAPEX ($)	Incremental OPEX (S/yr)	Cost Notes
Electrification of pneumatic devices at wellsite – High Cost Range	45,500	25,000	117	Costs for retrofit of an existing pneumatically operated well site with a solar-electric system (quote provided by vendor) including electric control panel, solar panels, batteries, electric chemical injection pump, electric controllers and electric actuators.
Electrification of pneumatic devices at wellsite – Low Cost Range	22,500	20,000	117	Costs for new build well site is estimated at $15,000 to $20,000 more for a solar-electric system (electric control panel, electric controllers, actuators, pumps, solar panels and batteries) than conventional pneumatic equipment (pneumatic controllers, actuators, switches, pumps etc.), as provided by vendor. Assumed well site has 1 pneumatic diaphragm pump and two pneumatic controllers. Cost varies depending on complexity of well site (e.g. # of controllers, actuators, pumps and solar panels and batteries required).

Costs are presented based on expected average sized well sites, where this option is applicable, however the range of costs can be expected change based on several factors including complexity of the site, scale of the site and location.

4.6 Replace Gas System with Air System for Pneumatic Devices

For facilities with numerous pneumatic components on site, such as compressor stations and gas plants, the pneumatic devices can be retrofitted to run on compressed air instead of fuel gas. Economics can be challenging as installation costs of retrofitting existing gas plants can be high relative to the low price of fuel gas that is conserved by making the change. Most existing facilities with instrument fuel gas do not have a grid electricity connection or would require electrical service upgrades to accommodate the additional load from the addition of an air compressor package (instrument air). There are several options that are available to provide sufficient electricity to a site in order convert all pneumatic devices from gas to air and the primary difference is based on the power source. There are currently four primary means of providing electricity to a site that can power an instrument air package.

- **Solid Oxide Fuel Cell (SOFC)** – Convert fuel to electricity though an electrochemical process instead of combustion of the fuel. The system modeled has a 200W min rating.
- **Thermoelectric Generator (TEG)** – Produces electricity based on a temperature differential that is applied to specific thermoelectric material. These systems are used at sites where there is excess waste heat available, but must be sized appropriately to ensure proper availability of power. The TEG modeled for these costs ranges from 50W to 200W.
- **Grid connection** – The site is connected to the grid and continuous power is available to the site. This option is only available where the distances permit the connection to the site. The costs for grid tie-in are estimated based on recent experiences in the field and assume $10,000 per km plus a $20,000 grid tie in cost. This does not include situations where powerline lifts or additional new poles might be required. Engineering charges from Utilities can also vary significantly and may increase the cost of grid connection projects.
- **Solar and Storage** – Solar panels generate electricity while batteries store power to maintain 10 days of autonomy for the system. The system (panels, batteries and air compressor) must be sized for the location and availability of sunlight in winter months.

The costs for these options were modeled based on data inputs from technology vendors and service providers and include the install costs that are required in each instance. Additional engineering time was also added to ensure that site modifications and sizing of the systems was included in the estimates. The range of potential costs will vary across Alberta in different locations and can vary considerably for each site. The costs that were modeled and included in Table 11 are based on a single gas well battery location. Costs for larger oil and gas batteries and gas gathering stations will be higher, however, there are efficiencies that are gained at larger sites by scaling the power source[8].

[8] Large facility Instrument Air projects have large ranges in costs and vary depending on the installation and preparation costs and are higher for old facilities that will require extensive electrical, mechanical and civil works. Total project costs for larger facilities have been reported by operators ranging from $50,000 to over $250,000.

Table 11 Instrument Air Power Options

Application	Installed Retrofit CAPEX ($)	Installed Greenfield CAPEX ($)	Incremental OPEX (S/yr)	OPEX Cost Assumptions
Instrument Air w/SOFC	61,784	54,370	$3000	Preventative maintenance is recommended to ensure filters are not clogged, perform engineering change orders, upgrade firmware and inspect for overall wear or damage. Costs over ten years can be 0.5 - 1.5 times the capital cost of the equipment[9].
Instrument Air w/ TEG	24,284	21,370	~$50	Recommended maintenance of one to two hours per year is required to check the power output and ensure a clean fuel supply by cleaning and/or changing the orifice and fuel filter. Consumables for recommended maintenance are typically less than one percent of the capital cost per year which is similar to pre-existing systems
Instrument Air w/ Grid (3km)	74,284	65,370	$0	Equivalent to pre-existing instrument gas system maintenance (fewer repairs offsets air compressor servicing costs)
Instrument Air w/ Solar	28,855	25,392	$117	Replace 4 batteries every 6 years (4*$175/battery[10])

Operational costs vary between the technology types and there are specific maintenance requirements for each of the power source technologies listed above. Each of the technologies has specific maintenance requirements that

[9] http://www.atrexenergy.com/assets/uploads/files/ARP_Series_DataSheet_Final_9-15-16_Low_Res.pdf

[10] Battery costs are highly dependant on the duty cycle of the compressor and the battery bank sizing can range significantly depending on the number of days of autonomy required at a site to achieve the desired duty cycle. Battery costs have been reported over $500 each at some sites. These systems are under continuous development by several vendors and costs range significantly between applications.

different depending on the size of the application and the OPEX costs provided above are for a range of potential installation sizes.

4.7 Vent Gas Capture to Combustor

Capture of vented gas from pneumatic devices and combustion in an efficient combustor achieves conversion of methane to CO2 which results in a decrease in overall emission intensity of the site from a global warming potential perspective. Combustor costs vary significantly between vendors and application to specific methane point sources. Combustors are references in several placed in this report[11] and while the equipment is similar and could possibly be applied in a similar fashion at each of the sites, the costs reported by vendors and from operators diverges between applications. Where possible, costs that are provided in each of the sections are specific to a size, application and configuration of the unit. The combustor would need to be sized appropriately to accommodate the correct volume of gas based on the number of devices and other sources. Enclosed combustors and incinerators do provide added benefits beyond typical flares including reduction of visible flame, ability to fully combust gas stream in all weather conditions and provide greater destruction efficiency. This combustion process does provide an opportunity to capture waste heat and re-purpose this energy if needed elsewhere on the site (TEG/Stirling Engine), however the costs modeled below do not include any heat recovery option.

A third option for vent gas capture is combustion in a catalytic heater. This option has limitation in terms of applicability and effectiveness in mitigating methane emissions. Catalytic heaters are generally limited to specific situations where the flowrate and backpressure allow for the correct sizing of the heater. The heaters only operate for around 8 months of the year when temperatures require the heat and the heater has a methane destruction efficiency of only 40-60% and can be problematic when the catalyst gets fouled. All these factors contribute to less than optimal methane reductions in practice. The costs provided in Table 12 are specific to 5100 style pumps due to requiring a specific backpressure on the pump vent. Other applications of catalytic heaters will vary in costs.

[11]See Table 12, Table 16, Table 19, Table 23,Table 23, Table 50

Table 12 Vent Gas Capture to Combustors

Application	Installed Retrofit CAPEX ($)	Installed Greenfield CAPEX ($)
Vent Gas Capture to Small Combustor (5000 scf/d)	21,000	16,500
Vent Gas Capture to Large Combustor (1.75 Mscf/d)	63,000	49,500
Vent Gas Capture to Catalytic Heaters	6,000	5,000

These costs include the cost of the combustors, install costs and engineering[12] costs required to complete the install. They do not include mobilization or significant travel costs that might be incurred to transport material and labour to remote locations in the province.

[12] Engineering costs for the greenfield installation are estimated to be 10% of equipment cost as they will be rolled into the overall site design. Retrofit engineering costs assumption (40% of equipment cost) is based on expectation that early design for combustors will require higher engineering design to tie in multiple low vent sources and account for back pressure tie in requirements

5 Compressors and Engines

Compressors and the associated engines are found throughout upstream natural gas production. The sizes and application can vary greatly which results in a wide spectrum of potential mitigation options and resulting costs. There are numerous potential methane mitigation options. Initial scans of publicly available cost data related to methane mitigation opportunities for compressors and engines revealed that the majority of the cost data available is from the EPA Gas Star program in the US. The detailed results of the initial public scan of compressor and engine cost details is included in Appendix 8.3. This information was outdated and not very applicable to the Alberta operational context due to the differences in site characteristics and remoteness of locations. In order to produce cost estimates that were reflective of the experiences in Alberta, AER SME and Technical Committees were engaged to provide data and expertise. Each option was evaluated and through committee discussions, bottom up modeled costs were generated. Bottom up calculations and the respective assumptions are outlined in the sections below.

Table 13 Summary Costs for Compressor and Engines Mitigation Options

Summary Table Mitigation Option	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Conversion of Gas Starter to Air Start	$ 235,836	$ 1,500	$ 293,916	$ 5,000
Starter Vent to Flare - Tie to Existing Flare Stack	$ 3,025	$ 150	$ 12,100	$ 150
Starter Vent to Flare - Tie to New Combustor	$ 51,425	$ 650	$ 60,500	$ 650
VRU Vent Capture to Inlet	$ 284,350	$ 5,000	$ 447,700	$ 5,000
Capture Packing Vents & Convey to Existing Flare	$ 45,980	$ 5,000	$ 182,710	$ 5,000
Capture Packing Vents & Convey to New Combustor	$ 94,380	$ 5,500	$ 231,110	$ 5,500
Capture Packing Vents & Convey to Existing Flare-No Vacuum	$ 18,150	$ -	$ 76,230	$ -
Capture Packing Vents to New Combustor-No Vacuum	$ 66,550	$ 500	$ 124,630	$ 500
Capture Blow Down to Inlet	$ 3,630	$ -	$ 12,100	$ -
Capture Blow Down to Inlet - Add a combustor	$ 52,030	$ 500	$ 60,500	$ 500
Capture atmospheric vents with SlipStream® SS3 standalone and convey to engine air inlet to blend with fuel gas	$ 27,500	$ 800	$ 52,250	$ 800
Capture atmospheric vents with SlipStream® SS10 standalone and convey to engine air inlet to blend with fuel gas	$ 37,400	$ 800	$ 61,050	$ 800
Capture atmospheric vents with SlipStream® SS10 in existing REMVue AFR and convey to engine air inlet to blend with fuel gas	$ 33,000	$ 800	$ 57,750	$ 800
Packing Rebuild to OEM Standard	$ -	$ -	$ 25,000	$ 6,250
Packing Upgrade to Low Bleed Packings	$ 3,000	$ -	$ 25,000	$ 6,250
Packing Build - Shutdown Seal	$ 15,000	$ 1,500	$ 35,000	$ 7,750
Centrifugal Seal Build - Dry Seal	$ -	$ -	$ 60,500	$ 5,000
Centrifugal Seal Build - Wet Gas Seal	$ -	$ -	$ 84,700	$ 6,000
Centrifugal Seal Build - Convert Wet Seal to Dry Seal	$ -	$ -	$ 1,452,000	$ 5,000
Meters - Low Flow Turbine with Flow Computer and Logger	$ 15,730	$ 500	$ 24,200	$ 1,000
Meters - Thermal Mass Flow Meter High Cost Range	$ 27,830	$ 500	$ 36,300	$ 1,000
Meters - Thermal Mass Flow Meter Low Cost Range	$ 10,890	$ 1,500	$ 19,360	$ 2,000
Meters - Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation	$ 605	$ -	$ 3,630	$ 500
Meters - Periodic Measurement with Thermal Mass Flow	$ 605	$ -	$ 3,630	$ 7,500

5.1 Conversion of Gas Starter to Air Starter

Internal combustion engines for compressors, generators, and pumps are started using small gas expansion turbine motor starters. Pressurized gas used to start the engine is vented to atmosphere. Replacing the gas with compressed air can reduce methane and VOC emissions.

The costs modeled for this mitigation option are based on a typical starter at 150psig minimum pressure, air consumption equal to 1700 scfm. Incremental cost for the additional duty on the plant air compressor is added to the greenfield estimate while a dedicated air compressor is required for the brownfield installation.

Table 14 Cost of Converting Gas Starter to Air Starter

Conversion of Gas Starter to Air Start Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Air compressor cw building (30 BHP 480V 110 scfm)	$ 52,000	$ 1,500	$ 52,000	$ 5,000
Receiver (13' S/S x 48" ID)	$ 45,600		$ 45,600	
Foundation	$ 7,000		$ 10,000	
Galvanized piping on rack	$ 3,306		$ 3,306	
PSV for 110 scfm	$ 2,000		$ 2,000	
Site electrical and MCC	$ 80,000		$ 120,000	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ 5,000		$ 10,000	
Sub total	**$ 194,906**	**$ 1,500**	**$ 242,906**	**$ 5,000**
Engineering (10%)	**$ 19,491**	**$ -**	**$ 24,291**	**$ -**
Contingency (10%)	**$ 21,440**	**$ -**	**$ 26,720**	**$ -**
Total	**$ 235,836**	**$ 1,500**	**$ 293,916**	**$ 5,000**

5.2 Starter Vent to Flare

Rather than venting pressurized gas that is used to start the engine to atmosphere, it can be diverted to a flare stack. Sites that have an existing flare stack can tie in the starter vent to the PSV header. If no flare is present at the site, a new combustor[13] can be added.

[13] See Table 12, Table 16, Table 19, Table 23, Table 23, Table 50

Table 15 Starter Vent to Flare - Existing Flare Stack

Starter Vent to Flare - Tie to Existing Flare Stack Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Tie starter vent piping to PSV Header	$ 1,500		$ 9,000	
Add two check valves (spec break)	$ 1,000	$ 150	$ 1,000	$ 150
Sub total	**$ 2,500**	**$ 150**	**$ 10,000**	**$ 150**
Engineering (10%)	**$ 250**	**$ -**	**$ 1,000**	**$ -**
Contingency (10%)	**$ 275**	**$ -**	**$ 1,100**	**$ -**
Total	**$ 3,025**	**$ 150**	**$ 12,100**	**$ 150**

Table 16 Starter Vent to Flare - New Combustor

Starter Vent to Flare - Tie to New Combustor Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Tie starter vent piping to PSV Header	$ 1,500		$ 9,000	
Add combustor to burn vented gas	$ 40,000	$ 500	$ 40,000	$ 500
Add two check valves (spec break)	$ 1,000	$ 150	$ 1,000	$ 150
Sub total	**$ 42,500**	**$ 650**	**$ 50,000**	**$ 650**
Engineering (10%)	**$ 4,250**	**$ -**	**$ 5,000**	**$ -**
Contingency (10%)	**$ 4,675**	**$ -**	**$ 5,500**	**$ -**
Total	**$ 51,425**	**$ 650**	**$ 60,500**	**$ 650**

5.3 Capture Vents with VRU

Compressors vent methane from packing vents and seals as a part of regular operation. This gas can be captured and diverted to a VRU that introduces the gas back to the inlet, thus avoiding the methane venting and conserving the gas for sales. Estimates are based on an electric drive VRU with two stages with bypass and make-up gas. A dedicated compressor is assumed to be added to greenfield and brownfield sites. The VRU is assumed to be located in an existing building in the greenfield installation.

Table 17 VRU Vent Gas Capture to Inlet

VRU Vent Capture to Inlet Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
VRU compressor (10 - 30 BHP @ 325 psig MAWP)	$ 90,000	$ 5,000	$ 150,000	$ 5,000
Two ESD valves	$ 20,000		$ 20,000	
Foundation	$ 7,000		$ 17,000	
Piping to inlet on rack	$ 20,000		$ 40,000	
Two check valves	$ 8,000		$ 8,000	
Site electrical and MCC	$ 80,000		$ 120,000	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ 10,000		$ 15,000	
Sub total	**$ 235,000**	**$ 5,000**	**$ 370,000**	**$ 5,000**
Engineering (10%)	**$ 23,500**	**$ -**	**$ 37,000**	**$ -**
Contingency (10%)	**$ 25,850**	**$ -**	**$ 40,700**	**$ -**
Total	**$ 284,350**	**$ 5,000**	**$ 447,700**	**$ 5,000**

5.4 Capture Packing Vent Route to Flare or Combustor

Reciprocating compressors vent from the rod packing as a part of normal operations. This vented gas can be captured with a vacuum pump and routed to an existing flare or, if a flare is not present at the site, a new combustor could be installed. Electric drive vacuum pumps with purge systems, seal pot and vacuum breakers are assumed to be installed. Dedicated systems are assumed for each compressor on both greenfield and brownfield sites. No additional buildings are assumed, but skid modifications are assumed for the brownfield sites. The estimates for the new combustor are assumed to be for sweet sites. As noted previously for combustor costs[14], the costs that were reported for this application differ from other point source emission applications for combustors and are representative of the understanding of what may be required to implement a combustor for this specific emission source.

Some implementations of capturing vented gas from rod packing may not require a vacuum pump. Cost without the vacuum pump and corresponding electrical requirements are presented in Table 20 and Table 21

Table 18 Cost to Capture Packing Vents with Vacuum Pump and Convey to Existing Flare

Capture Packing Vents & Convey to Existing Flare	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Vacuum pump	$ 18,000	$ 5,000	$ 18,000	$ 5,000
Purge system with rotameters	$ 8,000		$ 8,000	
Seal pot c/w instruments	$ 5,000		$ 5,000	
Piping to low pressure flare	$ 2,000		$ 20,000	
Skid modifications to accept new equipment	$ -		$ 15,000	
Site electrical and MCC	$ 5,000		$ 70,000	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 15,000	
Sub total	**$ 38,000**	**$ 5,000**	**$ 151,000**	**$ 5,000**
Engineering (10%)	**$ 3,800**	**$ -**	**$ 15,100**	**$ -**
Contingency (10%)	**$ 4,180**	**$ -**	**$ 16,610**	**$ -**
Total	**$ 45,980**	**$ 5,000**	**$ 182,710**	**$ 5,000**

[14] See Table 12, Table 16, Table 19, Table 23,Table 23, Table 50

Table 19 Costs to Capture Packing Vents with Vacuum Pump and Convey to New Combustor for Sweet Sites

Capture Packing Vents & Convey to New Combustor	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Vacuum pump	$ 18,000	$ 5,000	$ 18,000	$ 5,000
Purge system with rotameters	$ 8,000		$ 8,000	
Seal pot c/w instruments	$ 5,000		$ 5,000	
Piping to low pressure flare	$ 2,000		$ 20,000	
Skid modifications to accept new equipment	$ -		$ 15,000	
Site electrical and MCC	$ 5,000		$ 70,000	
Add combustor to burn vented gas	$ 40,000	$ 500	$ 40,000	$ 500
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 15,000	
Sub total	**$ 78,000**	**$ 5,500**	**$ 191,000**	**$ 5,500**
Engineering (10%)	**$ 7,800**	**$ -**	**$ 19,100**	**$ -**
Contingency (10%)	**$ 8,580**	**$ -**	**$ 21,010**	**$ -**
Total	**$ 94,380**	**$ 5,500**	**$ 231,110**	**$ 5,500**

Table 20 Packing Vent Capture to Existing Flare - No Vacuum Pump

Capture Packing Vents & Convey to Existing Flare-No Vacuum	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Purge system with rotameters	$ 8,000		$ 8,000	
Seal pot c/w instruments	$ 5,000		$ 5,000	
Piping to low pressure flare	$ 2,000		$ 20,000	
Skid modifications to accept new equipment	$ -		$ 15,000	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 15,000	
Sub total	**$ 15,000**	**$ -**	**$ 63,000**	**$ -**
Engineering (10%)	**$ 1,500**	**$ -**	**$ 6,300**	**$ -**
Contingency (10%)	**$ 1,650**	**$ -**	**$ 6,930**	**$ -**
Total	**$ 18,150**	**$ -**	**$ 76,230**	**$ -**

Table 21 Packing Vent to New Combustor - No Vacuum Pump

Capture Packing Vents to New Combustor-No Vacuum	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Purge system with rotameters	$ 8,000		$ 8,000	
Seal pot c/w instruments	$ 5,000		$ 5,000	
Piping to low pressure flare	$ 2,000		$ 20,000	
Skid modifications to accept new equipment	$ -		$ 15,000	
Add combustor to burn vented gas	$ 40,000	$ 500	$ 40,000	$ 500
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 15,000	
Sub total	**$ 55,000**	**$ 500**	**$ 103,000**	**$ 500**
Engineering (10%)	**$ 5,500**	**$ -**	**$ 10,300**	**$ -**
Contingency (10%)	**$ 6,050**	**$ -**	**$ 11,330**	**$ -**
Total	**$ 66,550**	**$ 500**	**$ 124,630**	**$ 500**

5.5 Capture Blowdown Gas and Route to Inlet

Compressors must periodically be taken off-line for maintenance, operational stand-by, or emergency shut down testing. When compressor units are shut down, typically the high-pressure gas remaining within the compressors and associated piping between isolation valves is vented to the atmosphere ('blowdown') or to a flare. In addition to blowdown emissions, a depressurized system may continue to leak gas from faulty or improperly sealed unit isolation valves. This option involves connecting blowdown vents to the inlet to recover some of the vent gas or to combust the gas in combustor.

In some instances, the control system can be reprogramed to open the suction control valve and ESD in order to blowdown the system to suction pressure. This removes a majority of the high-pressure gas from the higher-pressure stage gas and the remaining low-pressure gas can be diverted to a flare.

Table 22 Capture Blow Down to Inlet

Capture Blow Down to Inlet Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Reprogram control system to open suction pressure to blow down to inlet piping	$ 3,000		$ 10,000	
Sub total	**$ 3,000**	**$ -**	**$ 10,000**	**$ -**
Engineering (10%)	**$ 300**	**$ -**	**$ 1,000**	**$ -**
Contingency (10%)	**$ 330**	**$ -**	**$ 1,100**	**$ -**
Total	**$ 3,630**	**$ -**	**$ 12,100**	**$ -**

In cases where a site does not have an existing flare, a combustor can be added to the system.

Table 23 Capture Blowdown to Inlet - Add a Combustor

Capture Blow Down to Inlet - Add a combustor Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Reprogram control system to open suction pressure to blow down to inlet piping	$ 3,000		$ 10,000	
Add combustor to burn vented gas	$ 40,000	$ 500	$ 40,000	$ 500
Sub total	**$ 43,000**	**$ 500**	**$ 50,000**	**$ 500**
Engineering (10%)	**$ 4,300**	**$ -**	**$ 5,000**	**$ -**
Contingency (10%)	**$ 4,730**	**$ -**	**$ 5,500**	**$ -**
Total	**$ 52,030**	**$ 500**	**$ 60,500**	**$ 500**

5.6 Capture Atmospheric Vents with SlipStream®

SlipStream® a technology from Spartan Controls, is a mitigation option which captures vented gas from atmospheric vents and reroutes the vents to a fuel gas system where the gas is combusted in an engine offsetting fuel that would have otherwise been burned[15]. Multiple sources of vent gas can be captured and combusted in engine to reduce venting and replace a portion of the engine's primary fuel supply. The costs compiled are based on sweet applications, the vent systems are not trapped, includes a mass flow meter, control valves, transmitter, filter and the system is located within the compressor building. This option applies to sites where the engine has at least 350 BHP. Several models and configurations are available and representative costs for three specific configurations is provided in the tables below.

Table 24 Cost for SlipStream® SS3 Standalone

Capture atmospheric vents with SlipStream® SS3 standalone and convey to engine air inlet to blend with fuel gas	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Component				
SlipStream® SS3 standalone (<5 kg/h SS flow)	$ 17,000	$ 800	$ 17,000	$ 800
Piping to collect packing vents	$ 1,500		$ 5,000	
Install instruments and safety devices	$ 6,500		$ 15,000	
Piping on rack	$ -		$ -	
Site electrical and MCC	$ -		$ -	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 7,500	
Sub total	**$ 25,000**	**$ 800**	**$ 44,500**	**$ 800**
Engineering	**$ -**	**$ -**	**$ 3,000**	**$ -**
Contingency (10%)	**$ 2,500**	**$ -**	**$ 4,750**	**$ -**
Total	**$ 27,500**	**$ 800**	**$ 52,250**	**$ 800**

Table 25 Cost for SlipStream SS10 Standalone

Capture atmospheric vents with SlipStream® SS10 standalone and convey to engine air inlet to blend with fuel	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Component				
SlipStream® SS10 standalone (<10% of maximum fuel consumption)	$ 25,000	$ 800	$ 25,000	$ 800
Piping to collect packing vents	$ 1,500		$ 5,000	
Install instruments and safety devices	$ 7,500		$ 15,000	
Piping on rack	$ -		$ -	
Site electrical and MCC	$ -		$ -	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 7,500	
Sub total	**$ 34,000**	**$ 800**	**$ 52,500**	**$ 800**
Engineering		**$ -**	**$ 3,000**	**$ -**
Contingency (10%)	**$ 3,400**	**$ -**	**$ 5,550**	**$ -**
Total	**$ 37,400**	**$ 800**	**$ 61,050**	**$ 800**

[15] SlipStream® has three models: SS3 can handle up to 5kg per hour of vented gas; 5510 is designed for up to 10% of engine fuel load; 5550 can handle up to 50% of engine fuel load.

Table 26 Costs for SlipStream® SS10 in Existing REMVue AFR

Capture atmospheric vents with SlipStream® SS10 in existing REMVue AFR and convey to engine air inlet to blend with fuel gas	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Component				
SlipStream® SS10 in existing REMVue AFR (<10% of maximum fuel co	$ 22,000	$ 800	$ 22,000	$ 800
Piping to collect packing vents	$ 1,500		$ 5,000	
Install instruments and safety devices	$ 6,500		$ 15,000	
Piping on rack	$ -		$ -	
Site electrical and MCC	$ -		$ -	
Mobilization, demobilization, tailgate meetings, travel to site, subsis	$ -		$ 7,500	
Sub total	**$ 30,000**	**$ 800**	**$ 49,500**	**$ 800**
Engineering		**$ -**	**$ 3,000**	**$ -**
Contingency (10%)	**$ 3,000**	**$ -**	**$ 5,250**	**$ -**
Total	**$ 33,000**	**$ 800**	**$ 57,750**	**$ 800**

5.7 Reciprocating Compressor Rod Packing Early Replacement

Rod packing systems are used to maintain a seal around the piston rod, minimizing the leakage of high pressure gas from the compressor cylinder, while still allowing the rod to move freely. Some gas escapes through the rod packing, and this volume increases as the packing wears out over time. This option involves replacing, rebuilding and upgrading the rod, the packing case and seals to minimize leakage from worn out rod packing. The costs incurred for rod packing builds is dependant on the number of throws in a compressor. The costs modeled below are based on a typical compressor with 4 throws and a 4 year change out interval. Detailed cost estimates for replacements and rebuilds of the Packing rings, case and a rod refinish are provided for reference in Appendix 0

Detailed Packing Build **Options and Costs Estimates**.

Table 27 Packing Rebuild to OEM Standard[16]

Packing Rebuild to OEM Standard	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Packing rebuild to OEM standard (per occurrence)	$ -	$ -	$ 25,000	$ 6,250
Sub total	**$ -**	**$ -**	**$ 25,000**	**$ 6,250**
Total	**$ -**	**$ -**	**$ 25,000**	**$ 6,250**

An option to upgrade the rod packing is to use the low bleed packing rings packing system. This unique packing design reduces leakage, minimizing vent flow and lost process gas. It also loads sequentially, providing the equivalent of three sets of packings which enhances both packing life and sealing effectiveness.

Table 28 Packing Upgrade to Low Bleed Packings

Packing Upgrade to Low Bleed Packings	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Packing upgrade to Low Bleed Packing (per occurrence)	$ 3,000	$ -	$ 25,000	$ 6,250
Sub total	**$ 3,000**	**$ -**	**$ 25,000**	**$ 6,250**
Total	**$ 3,000**	**$ -**	**$ 25,000**	**$ 6,250**

A third option is to install a shutdown seal. This option prevents leaking gas when the compressor is shut down by applying dynamic pressure to the rods. These systems are available as kits.

Table 29 Packing Build - Shutdown Seal

Packing Build - Shutdown Seal	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Shut Down Seal		$ -		$ 6,250
Install control panel for Shutdown Seal	$ 10,000	$ 1,500	$ 10,000	$ 1,500
Labor for controls and installation	$ 5,000		$ 25,000	
Sub total	**$ 15,000**	**$ 1,500**	**$ 35,000**	**$ 7,750**
Total	**$ 15,000**	**$ 1,500**	**$ 35,000**	**$ 7,750**

5.8 Centrifugal Compressor Seal Builds

Centrifugal compressors, while not as common as reciprocating compressors in Alberta, have venting emissions that are meaningful in the Alberta Compressor inventory. In more vintage units, these compressors typically use high pressure oil (wet) seal systems in order to prevent gas migration between the rotating shafts. There are also dry seal alternatives that typically have much less associated gas migration. The replacement and rebuilding of seals reduces

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[16] The 4 year change out frequency is an estimate based on a per throw cost of $1562.50 per throw per year. For the assumed 4 throw compressor this is $6250 per year.

methane venting and it has also been shown that converting a centrifugal compressor from a wet seal system to a dry seal system can also significantly reduce methane venting through the seal. These options are only available on operating compressors and brownfield costs are provided. Dry seals have much less maintenance and operating costs associated with them vs. wet seals. Companies converted wet seals to dry seals for operating costs, safety and reliability considerations, not for emission reduction. That said capital costs and downtimes, can vary widely with seal changes. Estimated costs for representative options are presented in the tables below on what could be expected.

Table 30 Centrifugal Compressor Dry Seal Rebuild Costs

Centrifugal Seal Build - Dry Seal	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Dry seal rebuild to OEM standard (per occurrence)	$ -	$ -	$ 50,000	$ 5,000
Sub total	$ -	$ -	$ 50,000	$ 5,000
Engineering (10%)	$ -	$ -	$ 5,000	$ -
Contingency (10%)	$ -	$ -	$ 5,500	$ -
Total	$ -	$ -	$ 60,500	$ 5,000

Table 31 Centrifugal Compressor Wet Seal Rebuild Costs

Centrifugal Seal Build - Wet Gas Seal	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Wet gas seal rebuild to OEM standard (per occurrence)	$ -	$ -	$ 70,000	$ 6,000
Sub total	$ -	$ -	$ 70,000	$ 6,000
Engineering (10%)	$ -	$ -	$ 7,000	$ -
Contingency (10%)	$ -	$ -	$ 7,700	$ -
Total	$ -	$ -	$ 84,700	$ 6,000

Table 32 Centrifugal Compressor Wet to Dry Seal Conversion Costs

Centrifugal Seal Build - Convert Wet Seal to Dry Seal	Greenfield	Annual	Brownfield	Annual
Component	Installation	Maintenance	Installation	Maintenance
Convert wet seal to dry seal	$ -	$ -	$ 950,000	$ 5,000
Labor for controls and installation	$ -	$ -	$ 250,000	$ -
Sub total	$ -	$ -	$ 1,200,000	$ 5,000
Engineering (10%)	$ -	$ -	$ 120,000	$ -
Contingency (10%)	$ -	$ -	$ 132,000	$ -
Total	$ -	$ -	$ 1,452,000	$ 5,000

5.9 Pressure, Temperature and Mass Flow Meters

The use of pressure temperature and flow meters can serve several valuable purposes at oil and gas sites related to monitoring and tracking methane leaks and vents. The US EPA recently introduced additional regulations (US EPA Greenhouse Gas Reporting Rule: Subpart W) that require operators in the US to track and report vents which can be done with the use of specialized meters. Permanent meters can be installed at the locations of interest or periodic measurements can be taken by service providers. Costs for meters can vary with respect to meter type, logging and computational ability. Several options for meters are provided below.

Table 33 Costs of Installing Low Flow Turbine with Flow Computer and Logger

Meters - Low Flow Turbine with Flow Computer and Logger Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Low Flow Turbine with Flow Computer and Logger	$ 10,000	$ 500	$ 10,000	$ 500
Installation labor	$ 3,000		$ 10,000	$ 500
Sub total	$ 13,000	$ 500	$ 20,000	$ 1,000
Engineering (10%)	$ 1,300	$ -	$ 2,000	$ -
Contingency (10%)	$ 1,430	$ -	$ 2,200	$ -
Total	$ 15,730	$ 500	$ 24,200	$ 1,000

Table 34 Costs of Installing Thermal Mass Flow Meter High Cost Range

Meters - Thermal Mass Flow Meter High Cost Range Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Thermal Mass Flow Meter	$ 20,000	$ 500	$ 20,000	$ 500
Installation labor	$ 3,000		$ 10,000	$ 500
Sub total	$ 23,000	$ 500	$ 30,000	$ 1,000
Engineering (10%)	$ 2,300	$ -	$ 3,000	$ -
Contingency (10%)	$ 2,530	$ -	$ 3,300	$ -
Total	$ 27,830	$ 500	$ 36,300	$ 1,000

Table 35 Cost of Installing Thermal Mass Flow Meter Low Cost Range

Meters - Thermal Mass Flow Meter Low Cost Range Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Thermal Mass Flow Meter	$ 6,000	$ 1,500	$ 6,000	$ 1,500
Installation labor	$ 3,000		$ 10,000	$ 500
Sub total	$ 9,000	$ 1,500	$ 16,000	$ 2,000
Engineering (10%)	$ 900	$ -	$ 1,600	$ -
Contingency (10%)	$ 990	$ -	$ 1,760	$ -
Total	$ 10,890	$ 1,500	$ 19,360	$ 2,000

Table 36 Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation

Meters - Cost of Periodic Measurement by Positive Displacement with Pressure and Temp Compensation Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Third party periodic measurement Positive Displacement	$ -	$ -	$ -	$ 500
Third party periodic measurement if combined with Fugitive survey				$ 175
Installation labor	$ 500		$ 3,000	$ -
Sub total	$ 500	$ -	$ 3,000	$ 500
Engineering (10%)	$ 50	$ -	$ 300	$ -
Contingency (10%)	$ 55	$ -	$ 330	$ -
Total	$ 605	$ -	$ 3,630	$ 500

Table 37 Cost of Periodic Measurement with Thermal Mass Flow

Meters - Periodic Measurement with Thermal Mass Flow Component	Greenfield Installation	Annual Maintenance	Brownfield Installation	Annual Maintenance
Third party periodic measurement with Thermal Mass Flow	$ -	$ -	$ -	$ 7,500
Installation labor	$ 500		$ 3,000	$ -
Sub total	**$ 500**	**$ -**	**$ 3,000**	**$ 7,500**
Engineering (10%)	**$ 50**	**$ -**	**$ 300**	**$ -**
Contingency (10%)	**$ 55**	**$ -**	**$ 330**	**$ -**
Total	**$ 605**	**$ -**	**$ 3,630**	**$ 7,500**

6 Dehydrators

Dehydrators are used to process natural gas and reduce the moisture content of the gas to specified levels. Glycol dehydrators are the most common equipment used to remove water from gas and Triethylene Glycol (TEG) is the most common form of glycol used. In the process of removing the water, methane is also absorbed and other chemicals. Dehydrators work by placing the TEG in contact with the natural gas. The water and other chemicals are absorbed to the glycol, collected at the bottom of the contact vessel and sent to a regenerator. The regeneration process involves heating the rich glycol mixture to vaporize the water. Along with the water, methane and other chemicals can be vaporized and vented to atmosphere.

There are several mitigation options available to reduce the amount of methane that is vented to the atmosphere through this process and each has applicability in different circumstances. New glycol systems are generally packaged with additional measures in order to reduce methane venting from the system. Regular optimization through retrofits can be done on older systems and regular optimization of the system to match current throughput at the facility can also provide methane reductions. The costs modeled for these options are mostly based on publicly available data from the US and Canada. Where the reported costs differed from experiences from the technical and SME Committees, additional cost ranges were provided that can be used to provide relative potential costs for each option that may be experienced in an Alberta context.

A summary of the dehydrator methane mitigation options is included below in Table 38.

Table 38 Dehydrator Mitigation Option Cost Summary Table

Summary Table Mitigation Option	CAPEX - High Range	CAPEX - Low Range	Annual Maintenance
Install Flash Tank Separators on Dehydrators and Route Gas to Compressor, Reboiler, or Sales	$ 50,835	$ 13,139	$ -
Optimize Glycol Circulation Rates in Dehydrators	$ -	$ -	$ 540
Replace Gas Powered Glycol Pumps with Electric Glycol Pumps	$ 35,429	$ 13,880	$ -
Glycol Dehydrator Optimization	$ 199,273	$ 8,134	$ -
Stripping Gas Elimination	$ -	$ -	$ 500

6.1 Install Flash Tank Separators on Dehydrators and Recover Gas

As glycol absorbs water, it also absorbs methane, other volatile organic compounds (VOCs) and hazardous air pollutants. As the glycol is regenerated through heating in a reboiler, absorbed methane and other compounds are vented to the atmosphere with the water. Installing flash tank separators on glycol dehydrators reduces methane when the recovered gas is recycled to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine. US EPA compiled data on this item suggests that costs can be kept relatively low for small dehydrators that do not require extensive modifications or labour time to install a flash tank, however, more recent costs incurred by companies in Alberta suggest the costs may be much higher. It is expected that the costs would decrease as more installations are completed and efficiencies are realised.

Table 39 Dehydrator Flash Tank Separator Install Costs

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost and piping and materials	Flash Tank Separator Low cost	US EPA Gas STAR	$ 6,751
Component Cost and piping and materials	Flash Tank Separator High cost	Concoco CCEMC project data	$ 30,000
Installation Expenditrure (CAPEX)			
Installation Low	Includes delivery, assembly and labour	US EPA Gas STAR	$ 1,684
Installation High	Includes delivery, assembly and labour	Conoco CCEMC project data	$ 20,000
Total CAPEX High			**$ 50,000**
Total CAPEX Low			**$ 8,435**
Inflation and Currency Converted CAPEX High			**$ 50,835**
Inflation and Currency Converted CAPEX Low			**$ 13,140**

No additional non-energy OPEX costs are expected to be required for the installation of a flash tank separator.

6.2 Optimize Glycol Circulation Rates in Dehydrators

As TEG is regenerated through heating in a reboiler, absorbed methane and other compounds are vented to the atmosphere with the water. The amount of methane absorbed and vented is directly proportional to the TEG circulation rate. Wells and gathering systems may produce gas below the original design capacity, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality, much higher methane emissions and fuel use. Reducing circulation rates reduces methane emissions. This option does not require any additional equipment and simply requires that experienced field staff monitor the flowrates and adjusts the glycol circulation rates accordingly. This can generally be incorporated into standard maintenance checks and may benefit from a formalized procedure to be developed at each company. Cost estimates are based on average inspection times for typical dehydrator facilities in Alberta. Cost variability between sites will depend on dehydrator size, experience of the operators and vintage of the equipment.

Table 40 Costs for Glycol Circulation Rate Optimization

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost	Negligible	US EPA Gas STAR	$0
Installation Expenditrure (CAPEX)			
Labour	Negligible	US EPA Gas STAR	$0
Total CAPEX			**$0**
Non-Energy Operating Costs (OPEX)			
Maintenance	additional 4 hours inspection time and 2 hours to adjust circulation rates annualy.	Modeled estimates based on $90/hour per year	$540
Total OPEX ($/year)			**$540**

6.3 Replace Gas Powered Glycol Pumps with Electric Glycol Pumps

Most glycol dehydration systems rely on pumps to circulate the glycol through the dehydrator. Facility operators use two types of circulation pumps: gas-assisted glycol pumps, also referred to as "energy-exchange pumps," and electric pumps. Replacing gas pumps with electric pumps can increase system efficiency, reduce venting emissions and reduce fugitive emissions. Costs are estimates incorporate data from US EPA Gas STAR estimates as well as data inputs from AER SME committees. Costs range based on the size of the dehydrator and the size of the pump requires and therefore can create a broad range of potential costs.

Table 41 Replace Gas Powered Glycol Pumps with Electric Glycol Pump

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost - High		US EPA Gas STAR	$12,953
Component Cost - Low		US EPA Gas STAR	$1,425
Electrical Cost	VFD and associated electical cost (optional)	SME Committee Assumption	$5,000
Engineering Costs	Engineering costs estimated at 10% of capital costs	SME Committee Assumption	10%
Installation Expenditrure (CAPEX)			
Installation - High	Install is estimated at 10% of capital costs	US EPA Gas STAR	$1,795.30
Installation - Low	Install is estimated at 10% of capital costs	US EPA Gas STAR	$642.50
Total CAPEX High			**$ 21,544**
Total CAPEX Low			**$ 7,710**
Inflation and Currency Converted CAPEX High			**$ 33,560**
Inflation and Currency Converted CAPEX Low			**$ 12,010**

Operational costs are not included in this table as the operational and maintenance requirements for electric pumps are generally lower than the costs of the gas-powered pumps. In order to be conservative in the cost assessment, it is assumed there is no difference in the non-energy OPEX for the replacement of gas powered glycol pumps with electric pumps.

6.4 Glycol Dehydrator Optimization

Various technologies can be deployed to reduce methane emissions from glycol dehydrators. The simplest options include optimizing existing energy exchange (or gas-assisted) glycol circulation pumps to reduce size of pumps and/or reduce circulation rates or tying-in flash gas from flash tanks (that was previously vented) to compressor suction or to a flare system. Other more complex technologies include capturing and combusting vented gas in burners or engines or replacing gas-assisted glycol circulation pumps with electric pumps. Costs vary significantly depending on the solution.

A project example that provides cost data for Alberta specific dehydrator optimization projects was made available by ConocoPhillips at their 2015 CCEMC project workshop. The costs and gas savings are based on average of 13 ConocoPhillips projects to optimize glycol dehydrators to reduce methane emissions using five different technologies (Total $513k for all installations). Eight projects included optimizing the energy exchange pumps (replacing with smaller energy exchange pumps and/or reducing glycol circulation rates); three included capturing vented gas and combusting gas in a burner; one included a SlipStream® unit to capture gas and burn it in an engine; one included a flash tank tie-in to conserve gas; and one project included installation of an electric pump to remove the gas-assisted energy exchange pump entirely. Costs ranged from $8,000 for pump size reductions to $196,000 for Heat exchanger/Burner installation.

Table 42 Glycol Dehydrator Optimization Project Example Costs

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Average Project Cost	Average Capital and installation costs of 13 dehydration optimization projects	ConocoPhillips CCEMC Project Workshop (Dec 2015)	$ 38,700
Optimize Kimray Energy Exchange Pumps	Average cost of 8 projects		$ 8,000
Replace Gas Pump with Electric Pump	1 project		$ 30,000
Capture Vent Gas for Heat Exchanger/Combustor	Average cost of 3 projects		$ 196,000
Flash Tank Tie-in	1 project		$ 10,000
Slipstream to Engine	1 project		$ 100,000
Labour	Included in capital cost		
Total CAPEX High			**$ 196,000**
Total CAPEX Low			**$ 8,000**
Inflation Adjusted CAPEX - High			**$ 199,273**
Inflation Adjusted CAPEX - Low			**$ 8,134**

6.5 Stripping Gas Elimination

Stripping gas elimination is a process optimization strategy to realize methane reductions. It is likely that stripping gas is being overutilized in current operations. An examination of the dehydration process conditions can show that stripping gas is, either not needed at all or if needed, only required for a few weeks in the summer when ambient daytime temperatures are higher than the heat exchanger capacities of the gas and liquid streams. In these cases, stripping gas is used to achieve a higher purity of lean glycol for dehydration. If stripping gas elimination is possible, it would result in the closing of a stripping gas supply valve and possibly reproducing the Dehydrator Engineering and Operations Sheet (DEOS) sheet for that site.

Table 43 Stripping Gas Elimination Cost

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost	There are no capital costs for this option	AER SME Committee	$ -
Non-Energy Operating Costs (OPEX)			
Labour	Time required to assess site, close valve and update DEOS Sheet	AER SME Committee	$ 500
Total OPEX			**$ 500**

7 Oil and Gas Site Venting

Oil and Gas Sites have various instances where methane is vented as a part of normal operations either to perform an operational requirement or because the infrastructure is not present to capture and conserve the gas. These options have larger variability in costs attributed to site characteristic variance, operation types and travel time to remote sites.

A summary of the costs for methane mitigation from oil and gas site venting is include below in Table 44.

Table 44 Oil and Gas Site Venting Mitigation Option Cost Summary Table

Summary Table Mitigation Option	CAPEX - High Range	CAPEX - Low Range	OPEX - High Range	OPEX - Low Range
Plunger Lift Instead of Well Venting for Liquids Unloading	$ 16,200	$ 4,050	$ 1,300	$ 700
Reduce Liquids Unloading Venting - Flaring/Incineration/Destruction Device	$ 48,700	$ 46,700	$ -	$ -
Install Vapour Recovery Units on Storage Tanks	$ 185,078	$ 47,711	$ 16,839	$ 7,367
Recover Casing Vent and Use as Fuel, For Power Generation, connect to VRU	$ -	$ 6,166	$ -	$ -
Casing Gas Recovery Compressors (CHOPS)	$ 203,340	$ 41,685	$ 6,400	$ 5,000
Casing Gas Combustor/Incinerator (CHOPS)	$ 116,921	$ 76,253	$ 1,000	$ 277

7.1 Plunger Lift Instead of Well Venting for Liquids Unloading

Liquids unloading is the process of removing liquids from the bottom of gas wells when the accumulation is impeding the gas production. The liquids must be removed in order to allow effective production from the well. Venting the well is one method used. Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of methane venting.

Table 45 Plunger Lift Instead of Well Venting for Liquids Unloading Costs

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Capital Installation and Start up - High	Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear. The largest variable in the installation cost is running a wire-line to gauge the tubing (check for internal blockages) and test run a plunger from top to bottom (broaching) to assure that the plunger will move freely up and down the tubing string.	US EPA Gas STAR	$7800 /well
Capital Installation and Start up - Low		US EPA Gas STAR	$1900 /well
Installation Expenditrure (CAPEX)			
Start-up - High	Other start-up costs can include a well depth survey, swabbing to remove well bore fluids, acidizing to remove mineral scale and clean out perforations, fishing-out debris in the well, and other miscellaneous well clean out operations.	US EPA Gas STAR	$2600 / well
Start-up - Low		US EPA Gas STAR	$700 / well
Total CAPEX High	**$ 10,400**		
Total CAPEX Low	**$ 2,600**		
Inflation and Currency Converted CAPEX High	**$ 16,201**		
Inflation and Currency Converted CAPEX Low	**$ 4,050**		

Non-Energy Operating Costs (OPEX)			
Maintenance - High	Routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months	US EPA Gas STAR	$1300 /yr
Maintenance - Low		US EPA Gas STAR	$700 / yr
Total OPEX High	**$ 1,300**		
Total OPEX Low	**$ 700**		

7.2 Reduce Liquids Unloading Venting - Flaring/ Incineration/Destruction Device, Capture and Route to Sales or Fuel

One option to reduce methane emissions from liquids unloading is to use a portable or temporary flare system to burn vented emissions, which is required by law in some jurisdictions like British Columbia if there is sufficient volume. A portable flare would be used to flare gas from venting events, thus avoiding the release of methane.

Table 46 Costs to Reduce Liquids Unloading Venting

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost	trailer-mounted flare system ranging from 20 – 50 ft. in height, designed to handle gas flow rates of 1 - 10 MMscfd	EDF-ICF Methane Opportunities	$45,000
Installation Expenditrure (CAPEX)			
Labour - High	Flare operations and start-up	Estimate	$ 2,500.00
Labour - Low	Flare operations and start-up	Estimate	$ 1,200.00
Travel - High	Travel between sites	Estimate	$ 1,200.00
Travel - Low	Travel between sites	Estimate	$ 500.00
Total CAPEX High	**$ 48,700.00**		
Total CAPEX Low	**$ 46,700.00**		

There are no additional incremental OPEX costs associated with this option.

7.3 Install Vapour Recovery Units on Storage Tanks

Crude oil and liquid condensate at wells and gathering facilities is stored in fixed roof field tanks. Dissolved gas in the liquids is released and collects in the tank space above the liquid. This gas is often vented to the atmosphere or occasionally sent to the flare. Vapor recovery units (VRUs) collect and compress this gas, which can then be re-directed to a sales line, used on-site for fuel, or flared/incinerated.

Table 47 VRU on Storage Tank Costs

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost - High	500 Mcf/d design capacity	US EPA Gas STAR	$ 59,405
Component Cost - Low	25 Mcf/d design capacity	US EPA Gas STAR	$ 20,421
Installation Expenditrure (CAPEX)			
Install - High	500 Mcf/d design capacity	US EPA Gas STAR	$ 59,405
Install - Low	25 Mcf/d design capacity	US EPA Gas STAR	$ 10,207
Total CAPEX High	**$ 118,810**		
Total CAPEX Low	**$ 30,628**		
Inflation and Currency Converted CAPEX High	**$ 185,078**		
Inflation and Currency Converted CAPEX Low	**$ 47,711**		
Non-Energy Operating Costs (OPEX)			
O&M - High	500 Mcf/d design capacity	US EPA Gas STAR	$ 16,839
O&M - Low	25 Mcf/d design capacity	US EPA Gas STAR	$ 7,367
Total OPEX High	**$ 16,839**		
Total OPEX Low	**$ 7,367**		

7.4 Recover Casing Vent and Use as Fuel, For Power Generation, Connect to VRU.

Crude oil and natural gas wells that produce through tubing may collect methane and other gases in the annular space between the casing and tubing. This gas, referred to as casing head gas, is often vented directly to the atmosphere. One way to reduce methane emissions is to connect the casing head vent to an existing vapor recovery unit (VRU) where it can be re-routed to flare/incinerator/destruction device/gas collection piping network.

Table 48 Cost to Recover Casing Vent Gas

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost	Pressure regulators would be necessary if low pressure casinghead gas is combined with higher pressure sources (e.g., dehydrator flash tank separator) at a VRU suction. Only small diameter piping is required to join a casinghead vent to the VRU suction.	US EPA Gas STAR	4300/well
Total CAPEX High	**$ 4,300**		
Total CAPEX Low	**$ 4,300**		
Inflation and Currency Converted CAPEX High	**$ 6,166**		
Inflation and Currency Converted CAPEX Low	**$ 6,166**		

7.5 Casing Gas Recovery Compressors

Crude oil and natural gas wells that produce through tubing may collect methane and other gases in the annular space between the casing and tubing. This gas, referred to as casing head gas, is often vented directly to the atmosphere. This is very common in cold heavy oil production with sand (CHOPS). One way to reduce methane emissions is to connect the casing head vent to a small booster compressor to compress the gas to the point where it can be injected into a low-pressure pipeline. The cost range is based on 3 different casing gas recovery technologies that compress low pressure casing gas for input into pipeline or other beneficial use (SMD, Busch and Go Technologies).

Table 49 Casing Gas Recovery Compressors (CHOPS) Costs

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost - High	500-900 m3/day	PTAC/Sentio Engineering	$ 42,000
Component Cost - Low	0-500 m3/day	PTAC/Sentio Engineering - Go Technologies	$ 21,000
Installation Expenditrure (CAPEX)			
Install - High	500-900 m3/day	PTAC/Sentio Engineering	$ 158,000
Install - Low	0-500 m3/day	PTAC/Sentio Engineering - Go Technologies	$ 20,000
Total CAPEX High	**$ 200,000**		
Total CAPEX Low	**$ 41,000**		
Inflation Adjusted CAPEX - High	**$ 203,340**		
Inflation Adjusted CAPEX - Low	**$ 41,685**		
Non-Energy Operating Costs (OPEX)			
O&M - High	500-900 m3/day	PTAC/Sentio Engineering	$ 6,400
O&M - Low	0-500 m3/day	PTAC/Sentio Engineering - Go Technologies	$ 5,000
Total OPEX High	**$ 6,400**		
Total OPEX Low	**$ 5,000**		

7.6 Casing Gas Combustor/ Incinerator/Flare

Crude oil and natural gas wells that produce through tubing may collect methane and other gases in the annular space between the casing and tubing. This gas, referred to as casinghead gas, is often vented directly to the atmosphere. This is very common in cold heavy oil production with sand (CHOPS). One way to reduce methane emissions is to connect the casinghead vent to a combustor/flare/incinerator to destruct the waste gases. As mentioned in other sections of this report where combustors are used to mitigate various point sources, the costs reported for each opportunity differ significantly in some cases[17]. Additional pilot gas and purge gas may be required to operate the destruction device. Cost range is based on 5 different combustor/incinerator/flare technologies that combust waste gas streams (Hy-Bon, Black Gold Rush, TCI, SlipStream® GTS & flare stack).

[17] See Table 12, Table 16, Table 19, Table 23,Table 23, Table 50

Table 50 Casing Gas Combustor/Incinerator (CHOPS)

Cost items	Description	Reference	Amount
Capital Expenditrure (CAPEX)			
Component Cost - High	500-900 m3/day	PTAC/Sentio Engineering	$ 67,000
Component Cost - Low	0-500 m3/day	PTAC/Sentio Engineering	$ 16,000
Installation Expenditrure (CAPEX)			
Install - High	500-900 m3/day	PTAC/Sentio Engineering	$ 48,000
Install - Low	0-500 m3/day	PTAC/Sentio Engineering	$ 59,000
Total CAPEX High	**$ 115,000**		
Total CAPEX Low	**$ 75,000**		
Inflation Adjusted CAPEX - High	**$ 116,921**		
Inflation Adjusted CAPEX - Low	**$ 76,253**		
Non-Energy Operating Costs (OPEX)			
O&M - High	500-900 m3/day	PTAC/Sentio Engineering	$ 1,000
O&M - Low	0-500 m3/day	PTAC/Sentio Engineering	$ 277
Total OPEX High	**$ 1,000**		
Total OPEX Low	**$ 277**		

8 Appendices - Detailed Publicly Available Cost Data Tables

8.1 LDAR

Table 51 LDAR Details based on Publicly Available Sources

Mitigation Technology/Work Practice	CAPEX High (CAD 2016)	CAPEX Low (CAD 2016)	Annual OPEX High (CAD 2016)	Annual OPEX Low (CAD 2016)	Assumptions	References
Internal LDAR program, FLIR	n/a - included in OPEX		$15,249		Based on an hourly inspection cost of $192/hour calculated by ICF from the amortized cost of equipment (over 5 years) and labour (pg 3-13 of ICF Report, Table 3-3). Capital costs of $245.5k include $183.3k for infrared camera, $7.5k for photo ionization detector, $33k for truck, $21.75k for reporting system & $12.447k for training (one-off). Annual labour of $292.5k/year. Hourly rate calculated from (Amortized capital over 5 years + annual labour cost)/1880 hours/year.	ICF Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Gas Industries (Oct 2015)
Third Party LDAR program, FLIR	n/a - included in OPEX		$20,537		LDAR day rates based on rate sheet for LDAR service provider. Repair costs estimated from ICF report Table 3-4 on page 3-14 (gathering system repair costs).	Vendor quotes (confidential) for LDAR costs. Leak repair cost estimates based on ICF data and input from AER technical and subject matter expert committees.

8.2 Pneumatics

Table 52 Pneumatic Device Mitigation Details from Publicly Available Studies

Mitigation Technology / Work Practice	CAPEX High (CAD 2016)	CAPEX Low (CAD 2016)	OPEX High (CAD 2016)	OPEX Low (CAD 2016)	Assumptions	References
Replace High-Bleed Devices with Low-Bleed Devices	$2,125		$0		Average cost from 1062 installations. Includes several types of retrofits including high bleed Fisher 546 transducers and Fisher 4150 pressure controller replacements with new low bleed controllers (Fisher I2P-100 and Fisher C1). Assumed a 10-year project life.	ConocoPhillips CCEMC Project Workshop http://cetacwest.com/eco-efficiency/energy-efficiency-and-energy-management-workshops/2015-cpc
Replace High-Bleed Devices by Installing Retrofit Kits	$1,147		$0		Based on 110 retrofits of Fisher 4150 Controllers with Mizer Kits (after-market retrofit kit). Costs include travel, labour and component costs. Assumed a 10 year project life.	Callendar Energy Services.
Replace Pneumatic Pumps with Electric Pumps	$13,603	$9,608	$0	$0	High end of the range is based on ConocoPhillips CCEMC project, which included installation of 86 solar chemical injection pumps. Low end of range based on 138 solar pump installations in south-central Alberta. Includes a mix of single pumps and dual-headed pumps. CAPEX includes installation costs. Assumed a 10 year project life	ConocoPhillips CCEMC Project Workshop (Dec 2015).
Replace Gas System with Air System for	$361,788	$77,526	$7,884	$1,752	Based on 9 instrument gas to air conversion retrofits at small/medium-sized gas plants and compressor stations. Range of costs from $75,000 to $350,000.	Encana PTAC Presentation (Nov 18, 2014)

Pneumatic Devices						
Vent Gas Capture (SlipStream®) for Pneumatic Devices	$90,486		$400		CAPEX based on Encana average of 59 SlipStream® vent gas capture units. Gas savings based on typical compressor package with 5 pneumatic controllers, each venting 0.26 m3/h (9.2scfh) on average for a total vent rate of ~1.1mcfd. Vent rates from Prasino 2013 study averages for high bleed devices.	Encana CCEMC Project Report
Electrification of Pneumatic Devices (Retrofit)	$45,500	$22,500	$117		Costs for retrofit of an existing pneumatically operated well site with a solar-electric system (quote provided by vendor) including electric control panel, solar panels, batteries, electric chemical injection pump, electric controllers and electric actuators. Assumed baseline well site has 1 pneumatic diaphragm pump and two pneumatic controllers (assumed average vent rates from Prasino 2013 study). Cost varies depending on complexity of well site (e.g. # of controllers, actuators, pumps and solar panels and batteries required).	Calscan (technology vendor)
Electrification of Pneumatic Devices (New Build)	$25,000	$20,000	$117		Costs for new build well site is estimated at $15,000 to $20,000 more for a solar-electric system (electric control panel, electric controllers, actuators, pumps, solar panels and batteries) than conventional pneumatic equipment (pneumatic controllers, actuators, switches, pumps etc.), as provided by vendor. Assumed well site has 1 pneumatic diaphragm pump and two pneumatic controllers (assumed average vent rates from Prasino 2013 study). Cost varies depending on complexity of well site (e.g. # of controllers, actuators,	Calscan (technology vendor)

				pumps and solar panels and batteries required).	
Vent Gas Capture from Membrane Dryers (SlipStream®)	$90,486		$400	Costs and gas savings based on average of 59 SlipStream® vent gas capture units installed to capture vent gas from membrane dryers. Gas savings of 6.8mcfd average based on actual results reported to CCEMC.	Encana CCEMC Project Report

8.3 Compressors and Engines

Table 53 Compressor and Engine Mitigation Details from Publicly Available Sources

Mitigation Technology/ Work Practice	CAPEX High (CAD 2016)	CAPEX Low (CAD 2016)	Annual OPEX High (CAD 2016)	Annual OPEX Low (CAD 2016)	Assumptions	References
Conversion from Gas to Air Starting	$717		$500		- Applies to ICEs for compressors, generators, and pumps started using gas expansion turbine motor starters. - High pressure NG is stored in a tank to feed the expansion turbine. This is replaced with compressed air in this option. - Air compressor required. May only be cost-effective if air compressor already on-site (which would also need a grid electricity supply).	US EPA Gas STAR https://www.epa.gov/natural-gas-star-program/replace-gas-starters-air-or-nitrogen

Conversion from Gas to Nitrogen Starting	$717		$250		- Applies to ICEs for compressors, generators, and pumps started using gas expansion turbine motor starters. - High pressure NG is stored in a tank to feed the expansion turbine. This is replaced with nitrogen in this option. - Pressurized nitrogen from an onsite nitrogen rejection unit (NRU) is the most viable supply	US EPA Gas STAR https://www.epa.gov/natural-gas-star-program/replace-gas-starters-air-or-nitrogen
Conversion from Gas Starting to Electric Motor Starters	$14,340	$1,434	$107		- Electric motor starters require a power supply	US EPA Gas STAR https://www.epa.gov/sites/production/files/2016-06/documents/installelectricstarters.pdf
Reducing Emissions When Taking Compressors Offline (Blowdowns) - Connect to Fuel Gas Line	$4,050	$2,290	$0	$0	- Keep the compressor at fuel gas pressure and connect blowdown vent to fuel gas line or other low pressure gas line	US EPA Gas STAR https://www.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf
Reciprocating Compressor Rod Packing Early Replacement	$841		$0		- Replace rod packing every three years	US EPA Gas STAR https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf
Air Fuel Ratio Controller	$230,868	$140,528	$0		- the greatest opportunities for significant system and efficiency improvements are for rich burn, high-speed, turbocharged engines ranging in size from 1,000 hp to 3,000 hp	US EPA Gas STAR

Vent Gas Capture from Reciprocating Compressor Packing Vents	$321,277	$116,921	$0	Costs and gas savings based on average of 5 ConocoPhillips vent gas capture units installed to capture vent gas from reciprocating compressor packing vents (note that 4 projects captured packing vents and one project captured dehydrator still column overheads and the averages included all project types). Gas savings of 10.1mcfd average based on actual results reported at CCEMC workshop in Dec 2015. Average costs were $254k with a range from $115k to $316k. High costs include the cost of upgrading control panels and installing air fuel ratio systems.	ConocoPhillips CCEMC Project Workshop (Dec 2015)

8.3.1 Detailed Packing Build Options and Costs Estimates

Table 54 Detailed Packing Build Option Costs

Packing Build Options - Detailed Cost Estimates	Cost	Units
Replace Packing Rings	**$1,200**	/Throw
Equipment Costs	$400	/Throw
Rings (assumes 4 rings/throw)	**$400**	
$/Cup - 2.5" Diameter Rod	**$318**	
Compressor Down Time	**4**	hr/compressor
Time	**6**	hr/compressor
Travel Distance	**100**	km
Travel Cost	**$1.6**	/km
Number of People	**1**	
Hourly	**$160**	/hr
Other Work	**Yes**	(Yes/No)
Rebuilt Packing Case and Rings	**$5,926**	/Throw
Equipment Costs	$3,446	/Throw
Rings (assumes 4 rings/throw)	**$200**	
Rod Inspection	**$700**	
# of Cups	**8**	
$/Cup - 2.5" Diameter Rod	**$318**	
Packing Case	**$2,546**	
Compressor Down Time	**10**	hr/compressor
Time	**10**	hr/compressor
Travel Distance	**100**	km
Travel Cost	**1.6**	/km
Number of People	**2**	
Hourly	**160**	/hr
Rebuild Rod, Packing Case and Rings	**$6,906**	/Throw
Equipment Costs	$3,946	/Throw
Rings (assumes 4 rings/throw)	**$200**	
Rod Inspection	**$700**	
Rod Re-Finish	**$500**	
# of Cups	**8**	
$/Cup - 2.5" Diameter Rod	**$318**	
Packing Case	**$2,546**	
Compressor Down Time	**36**	hr/compressor
Contractor Time	**12**	hr/compressor
Travel Distance	**100**	km
Travel Cost	**$1.6**	/km
Number of People	**2**	
Hourly	**$160**	/hr

8.4 Dehydrators

Table 55 Dehydrator Mitigation Option Details from Publicly Available Sources

Mitigation Technology/ Work Practice	CAPEX High (CAD 2016)	CAPEX Low (CAD 2016)	Annual OPEX High (CAD 2016)	Annual OPEX Low (CAD 2016)	Assumptions	References
Install Flash Tank Separators on Dehydrators and Route Gas to Compressor, Reboiler, or Sales	$13,140	$10,516	$0	$0	As triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants. As TEG is regenerated through heating in a reboiler, absorbed methane and other compounds are vented to the atmosphere with the water. Installing flash tank separators on glycol dehydrators reduces methane when the recovered gas is recycled to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine.	EPA - Global Mitigation of Non-CO2 GHGs EPA Gas STAR - https://www3.epa.gov/gasstar/documents/ll_flashtanks3.pdf https://www3.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf

Optimize Glycol Circulation Rates in Dehydrators	$0	$0	$0	$0	As triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants. As TEG is regenerated through heating in a reboiler, absorbed methane and other compounds are vented to the atmosphere with the water. The amount of methane absorbed and vented is directly proportional to the TEG circulation rate. Wells may produce gas below the original design capacity but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing circulation rates reduces methane emissions.	EPA - Global Mitigation of Non-CO2 GHGs EPA Gas STAR - https://www3.epa.gov/gasstar/documents/ll_flashtanks3.pdf https://www3.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf
Replace Gas Powered Glycol Pumps with Electric Glycol Pumps	$22,196	$2,442	$4,646	$357	Replacing gas-assisted pumps with electric pumps increases system efficiency and significantly reduces emissions.	https://www.epa.gov/sites/production/files/2016-06/documents/ll_glycol_pumps3.pdf
Reroute Glycol Skimmer Gas	$2,868		$1,000	$100	Some glycol dehydrators have glycol vent condensers and condensate separators to recover natural gas liquids and reduce VOC and pollutant emissions. The non-condensable gas from the condensate separator, which contains mostly methane, is vented to the atmosphere. The gas could be re-routed to the reboiler firebox or other low pressure fuel gas systems for use.	EPA Gas STAR - https://www3.epa.gov/gasstar/documents/rerouteglycolskimmer.pdf

Glycol Dehydrator Optimization	$39,346	$0	Costs and gas savings based on average of 13 ConocoPhillips projects to optimize glycol dehydrators to reduce methane emissions using 5 different technologies (Total $513k for all installations). 8 projects included optimizing the Kimray energy exchange pumps (replacing with smaller Kimray pumps and/or reducing glycol circulation rates); 3 included capturing vented gas and combusting gas in a burner; 1 included a Slip Stream unit to capture gas and burn it in an engine; 1 included a flash tank tie-in to conserve gas; and 1 project included installation of an electric pump to remove the gas-assisted Kimray pump entirely. Costs ranged from $8,000 for pump size reductions to $196,000 for Heat exchanger/Burner installation.	ConocoPhillips CCEMC Project Workshop (Dec 2015)

8.5 Oil and Gas Sites

Table 56 Oil and Gas Site Specific Mitigation Option Details from Publicly Available Sources

Mitigation Technology/Work Practice	CAPEX High (CAD 2016)	CAPEX Low (CAD 2016)	Annual OPEX High (CAD 2016)	Annual OPEX Low (CAD 2016)	Assumptions	References
Plunger Lift Instead of Well Venting for Liquids Unloading	$16,201	$4,050	$1,300	$700	Liquids unloading is the process of removing liquids from the bottom of gas wells when the accumulation is impeding the gas production. The liquids must be removed in order to allow effective production from the well. Venting the well is one method used. Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more	https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf

					efficiently while controlling and limiting the amount of methane venting.	
Reduce Liquids Unloading Venting - Flaring/ Incineration/Destruction Device, Capture and Route to Sales or Fuel	$48,700	$46,700	$0	$0	One option to reduce methane emissions from liquids unloading is to use a portable or temporary flare system to burn vented emissions, which is required by law in some jurisdictions like British Columbia if there is sufficient volume. A portable flare would be used to flare gas from venting events, thus avoiding the release of methane.	https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
Install Vapour Recovery Units on Storage Tanks	$185,078	$47,711	$16,839	$7,367	Crude oil and liquid condensate at wells and gathering facilities is stored in fixed roof field tanks and dissolved gas in the liquids is released and collects in the tank space above the liquid. This gas is often vented to the atmosphere or occasionally sent to the flare. Vapor recovery units (VRUs) collect and compress this gas, which can then be re-directed to a sales line, used on-site for fuel, or flared/incinerated.	http://www.unimaclp.com/wp-content/uploads/2012/12/install_vru_storage_tanks.pdf
Recover Casing Vent and Use as Fuel, For Power Generation, Connect to VRU.	$6,166		$3,627		Crude oil and natural gas wells that produce through tubing may collect methane and other gases in the annular space between the casing and tubing. This gas, referred to as casinghead gas, is often vented directly to the atmosphere. One way to reduce methane emissions is to connect the casinghead vent to an existing vapor recovery unit (VRU) where it can be re-routed to flare/incinerator/destruction device. This option is applicable at producing through tubing packerless completions.	https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf

Casing Gas Recovery Compressors	$203,340	$41,685	$5,000	$6,400	Cost range based on 3 different casing gas recovery technologies that compress low pressure casing gas for input into pipeline or other beneficial use (SMD, Busch and Go Technologies). Gas savings were estimated based on mid point of size range of each system (e.g. for a 500-900 m3/day system the midpoint of 700 m3/day was selected).	PTAC/Sentio Engineering. Oct 2015. "Technology for Emissions Reductions. Cold Heavy Oil Production with Sand (CHOPS) - Methods for Reduction of Methane Venting."
Casing Gas Combustor/ Incinerator/Flar e	$116,921	$76,253	$1,000	$277	Cost range based on 5 different combustor/incinerator/flare technologies that combust waste gas streams (Hy-Bon, Black Gold Rush, TCI, SlipStream® GTS & flare stack). Gas savings were estimated based on mid point of size range of each system (e.g. for a 500-900 m3/day system the midpoint of 700 m3/day was selected).	PTAC/Sentio Engineering. Oct 2015. "Technology for Emissions Reductions. Cold Heavy Oil Production with Sand (CHOPS) - Methods for Reduction of Methane Venting."