Energy Efficiency Potential in Canada's Upstream Oil and Gas Sector

Final Report

Project 115301592

Prepared for:
NRCan
Ottawa, ON

Prepared by:
Stantec Consulting Ltd.

In Association with:
Marbek Resource Consultants Ltd.

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Executive Summary

Natural Resources Canada (NRCan)'s Office of Energy Efficiency (OEE) engaged Stantec Consulting Ltd. (Stantec) and Marbek Resource Consultants Ltd (Marbek) to undertake a study into the energy efficiency potential of Canada's upstream oil and gas (UOG) sector.

The objectives of the study were to: develop an energy use profile for the UOG sector; identify technical and management best practices (TBPs and MBPs) that could be implemented and their current implementation rates; and to calculate the potential improvements to energy consumption and greenhouse gases (GHGs) that could be achieved if the best practices were implemented. The base year for the study was 2005 and projections of energy use with/out the implementation of best practices were made for milestone years up to 2030.

Six sub-sectors of the UOG were examined: natural gas producers, processors (sweet) and processors (sour); and crude oil producers/processors in the light/medium, conventional heavy and bitumen sub-sectors.

Primary data collection from UOG companies/facilities as well as secondary data collection from a number of sources was used to inform the study results, including energy end-use and market penetration of TBPs. A recruitment target of 72 facilities was established but owing to difficulties out of the project team's control, such as company mergers, this target was not reached. In order to complete the project within the timeline, recruitment was therefore curtailed with a total of 30 facilities from 15 companies represented in the study. The companies included give a good cross-section of the industry (6 majors, 5 trusts and 4 intermediate/juniors) and results should be reasonable at a sector level. At a sub-sector level, however, the sample sizes are small and results should be treated with caution.

Participants were surveyed on their implementation of 48 TBPs and a further 20 Waste Reduction Best Practices (WRBPs), as well as extensively questioned on their implementation of MBPs.

Key findings of the study include:

- Based on the current market penetration of TBPs, the technical potential for energy savings in the UOG sector is 16% or 186 petajoules (PJ) by 2030, compared to a 'business-as-usual' projection of energy consumption. This assumes that all TBPs that are technically feasible are implemented, regardless of economics. When an economic test is applied to the TBPs – in this case, the Total Resource Cost test – the savings potential drops to 13% by 2030, a saving of 147 PJ of energy.

- It is estimated that considerable additional savings of up to 128 PJ technical potential could be realized through the adoption of high efficiency incinerators to replace existing flares, dehydrator regenerators and incineration stacks. This issue could not be examined

in detail within this study but owing to its significant potential should be looked at further in another study.

- Further savings could be realized through improved design practices in the construction of new plants and through the earlier adoption of cutting edge technologies. Cutting edge technologies are however traditionally resisted by the UOG sector until they are firmly proven in the field – of thirteen companies responding to this issue, eight noted that were not willing to be involved in piloting such technology. Demonstration projects for new technologies are therefore likely to be an important method for encouraging greater efficiency.

- The largest absolute energy savings potential is in the Bitumen sub-sector, due to its high rate of anticipated growth to 2030 (the sector is expected to triple in size over this time period). The largest percentage savings is in the Conventional Heavy Oil sub-sector.

- In terms of energy end-uses, direct fired heaters and steam boilers consume around 65% of the total energy use in the UOG sector, followed by incinerators with 21% energy use. The implementation of TBPs for direct fired heaters/steam boilers was generally low, and as such, process heating offers by far the highest level of both technical and economic energy efficiency potential. Efforts to reduce energy consumption and improve efficiency in the UOG sector should therefore focus on this area.

- Similar TBPs were found to have different level of implementation from one sub-sector to another, which may suggest an opportunity for transferring success stories across sub-sectors, but may also be indicative of barriers to implementation that are sub-sector-specific. However, more research would be required to investigate this issue due to the low number of facilities included at the sub-sector level.

- For each sub-sector, there were a number of TBPs that were 100% implemented. These measures are likely to have become mainstream practices and should not be included in future studies. However, one should be cautious in this interpretation because of an insufficient statistical reliability due to the low level of industry participation in this study. Nevertheless, this does indicate that the UOG industry is receptive to adopting proven energy efficiency measures.

- The Natural Gas Producers (Sour) sub-sector scored the highest in MBP with 54% implementation while Light and Medium Oil scored the lowest with 20% implementation. There is clearly much room for improving energy efficiency management within the UOG sector, particularly in the areas of policy and planning, training and capacity building. In themselves, these activities may not directly save much energy. However, they will provide a solid platform for companies to launch systematic, targeted and effective implementation of TBPs.

- Some companies have a high level of MBP implementation (up to 81% in the sample studied). The potential therefore exists to work with these companies to provide demonstrable leadership to their peers regarding the benefits of energy management and the practical lessons on how to implement it at a company or facility. This could also help overcome UOG sector reluctance to pilot 'cutting edge' best practices.

- WRBPs have a higher level of market penetration than the TBPs, probably due to the regulatory environment around flaring, venting and fugitive emissions in Alberta.

- Water produced did not show a conclusive trend as half of the companies did not report on water production. However, this is known to be an important parameter affecting energy consumption and future studies should take this into account.

- There area number of significant barriers to the implementation of energy efficiency in the UOG sector, including a short-term focus, lack of information/resources to tackle energy efficiency, a culture of risk avoidance, suspicion of government and specific financial disincentives to conserve energy. These barriers must be addressed if energy efficiency is to be improved.

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Table of Contents

1.0 Introduction 1
1.1 Background 1
1.2 Study Objectives 1
1.3 Report Presentation 2

2.0 Methodology 3
2.1 Profiling Energy Use 3
2.2 Analysis Steps 4
2.3 Project Implementation 5
2.3.1 Industry Recruitment 5
2.3.2 Data Collection from Recruited Facilities 8
2.3.3 Data Collection from Secondary Sources 9
2.3.4 Filling the Survey Information Gaps 9

3.0 Upstream Oil & Gas Sector Profile 10
3.1 Sub-sectors of Definition 10
3.2 Coverage of Energy Supply 11
3.3 GHG Emission Factors 12
3.4 End Uses 13
3.4.1 Energy End Uses 13
3.4.2 End Uses and Activities Related to Waste Reduction 14

4.0 Base Year and Reference Case Energy and GHG Emissions Profile 15
4.1 Base Year 15
4.1.1 Base Year Methodology 15
4.1.2 Base Year Energy Use 18
4.1.3 Base Year Energy Use by End Use 19
4.2 Reference Case 20
4.2.1 Reference Case Methodology 20
4.2.2 Reference Case Energy Use 21

5.0 Technical Potential for Energy Efficiency 23
5.1 Methodology 23
5.1.1 Identifying and Defining Energy Efficiency Opportunities 23
5.1.2 Benchmarking the Implementation of Opportunities 24
5.1.3 Modeling Technical Potential 25
5.2 Technical Best Practices 25

5.3 Implementation of Technical Best Practices 29
5.4 Sector and Sub-sector Energy Efficiency Technical Potential and GHG Emission Reduction 34

6.0 Economic Potential for Energy Efficiency........................ 38
6.1 Methodology 38
6.2 Economic Screening of Best Practice Opportunities 38
6.3 Sector and Sub-sector Energy Efficiency Technical Potential and GHG Emission Reduction 41
6.4 Economic Potential Cost Curves 45
6.4.1 Methodology 45
6.4.2 Cost Curves 46

7.0 Implementation and Management Best Practice.............. 53
7.1 Methodology 53
7.2 Management Best Practice Results 53
7.3 Trends and Correlations 54

8.0 Waste Reduction...57
8.1 Methodology 57
8.2 Waste Reduction Opportunities 57
8.3 Waste Reduction Potential 59

9.0 Barriers to Implementation fo Energy Efficiency Projects.....61
9.1 Attitude and Focus of the UOG Sector 61
9.2 Cost of Fuel Gas 61
9.3 Energy Conservation Policies 62
9.4 Financial Risk and Perception 62
9.5 Lack of Information and Resources 62
9.6 Heterogenity of Asset base 63

10.0 Summary and Conclusions.................................... 64

11.0 Acknowledgements...66

12.0 References...67

Appendices A - G.. i

List of Figures

Figure 1	Generic Concept of Energy Potential Analysis	4
Figure 2	Inventory of Canadian UOG Facilities	6
Figure 3	Number of Plants by Sub-sector	8
Figure 4	Elements Informed by Secondary Sources	9
Figure 5	GHG Emission Factors for Natural Gas and Fuel Gas	12
Figure 6	GHG Emission Factors for Natural Gas, Fuel Gas, and Electricity in CO2e/GJ	12
Figure 7	End Uses	12
Figure 8	List of Waste Reduction End Uses and Activities	14
Figure 9	Approach to Develop Sub-sector Energy Use Profiles	15
Figure 10	Example Templates Illustrating Development of Sub-sector Energy Use Profile	16
Figure 11	Cumulative Sub-sector % Energy Use a Function of Facility Size and Number	17
Figure 12	Estimated Number of Medium and Large Facilities	17
Figure 13	2005 Base Year Energy Use by Fuel Type [PJ]	18
Figure 14	2005 Base Year Energy Use by Sub-Sectors (excluding RPP) [PJ]	18
Figure 15	2005 Base Year Energy Use by End Use (excluding RPP) [PJ]	19
Figure 16	2005 Base Year Energy Use by End Use and Sub-sector [PJ]	20
Figure 17	Reference Case Energy Use by Energy Source [PJ]	21
Figure 18	Graphic Representation of Reference Case Energy Use by Energy Source [PJ]	22
Figure 19	Reference Case Energy Use by Sub-sector	22
Figure 20	Sample TBP Survey Score Chart	24
Figure 21	List of TBP for the UOG Sector	26
Figure 22	Breakdown of Sub-sector Specific Processes by Generic End Uses and Fuel Type	29
Figure 23	Implementation of TBP in the Natural Gas Producers Sub-sector	29
Figure 24	Implementation of TBP in the Natural Gas Producers - Sweet Sub-sector	30
Figure 25	Implementation of TBP in the Natural Gas Producers - Sour Sub-sector	31
Figure 26	Implementation of TBP in the Light and Medium Oil Sub-sector	31
Figure 27	Implementation of TBP in the Conventional Heavy Oil Sub-sector	32
Figure 28	Implementation of TBP in the Bitumen Sub-sector	32
Figure 29	List of TBP Considered Standard Practice by Sub-sector	33
Figure 30	Reference Case and Technical Potential Scenario Energy Use for Total UOG	35
Figure 31	Reference Case and Technical Potential Scenario Energy Use by Energy Source [PJ]	36
Figure 32	2030 Technical Potential Scenario Energy Savings by End Use	36
Figure 33	Reference Case and Technical Potential Scenario Energy use by Sub-sector [PJ]	37
Figure 34	TRC of Best Practices (Example Using Natural Gas Processors - Sour)	39
Figure 35	Reference Case and Economic Potential Scenario Energy Use for the UOG Sector	42
Figure 36	Reference Case and Economic Potential Scenario Energy Use by Sub-sector [PJ]	43
Figure 37	Reference Case and Economic Potential Scenario Energy Use by Fuel Type [PJ]	43

Figure 38 Reference Case and Economic Potential Scenario Energy Use by End Use [PJ] 44
Figure 39 GHG Savings Associated with the Economic Potential Scenario by Sub-sector 44
Figure 40 Cost Curve for Natural Case Producers 47
Figure 41 Cost Curve for Natural Case Producers - Sweet 47
Figure 42 Cost Curve for Natural Case Producers - Sour 48
Figure 43 Cost Curve for Light and Medium Oil 49
Figure 44 Cost Curve for Conventional Heavy Oil 50
Figure 45 Cost Curve for Bitumen 51
Figure 46 Aggregate Cost Curve for the UOG Sector 52
Figure 47 Implementation of MBP by Sub-sector (%) 53
Figure 48 Implementation of MBP by Best Practices Category (%) 54
Figure 49 Relationship Between Facility Number of Employees and Implementation of Energy Monitoring Systems 56 56
Figure 50 Relationship between facility number of employees and MBP score 58
Figure 51 List of Waste Reduction Best Practices 59
Figure 52 Reference Case for Natural Gas Wasted by Flaring in Canada's UOG Sector [GJ] 60
Figure 53 Implementation of Waste Reduction Best Practices 61

List of Abbreviations

API - American Petroleum Institute
CAC - Criteria Air Contaminants
CAPP - Canadian Association of Petroleum Producers
CH4 - Methane
CHOA - Canadian Heavy Oil Association
CO2 - Carbon Dioxide
CSS - Cyclic Steam Saturation
EOR - Enhanced Oil Recovery
ERCB - Energy and Resources Conservation Board
GHG - Greenhouse Gases
GJ - Gigajoules
GWP - Global Warming Potential
H2S - Hydrogen Sulphide
LPG - Liquid Petroleum Gas
MBP - Management Best Practices
N2O - Nitrous Oxide
NAICS - North American Industry Classification System
NEB - National Energy Board
NG - Natural Gas
NPV - Net Present Value
NRCan - Natural Resources Canada
OEE - Office of Energy Efficiency
PJ - Petajoules
PTAC - Petroleum Technology Alliance Canada
PVC - Present Value Costs
ROI - Return on Investment
RPP - Refined Petroleum Products
SAGD - Steam Assisted Gravity Drainage
SEPAC - Small Explorers and Producers Association Canada
SRU - Sulphur Recovery Unit
TBP - Technical Best Practices
TRC - Total Resource Cost
UOG - Upstream Oil and Gas
WRBP - Waste Reduction Best Practices

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

1.0 Introduction

1.1 Background

Energy management is a multifaceted approach that includes study, analysis and implementation of energy efficient technical and management best practices. Energy management is increasingly being recognized as the key methodology to exploit industrial energy efficiency potential and is an indispensable strategy to help sustain the key sectors of our economy and reduce industry's negative impact on climate change through the following benefits:

- Reduced operating costs
- Increased productivity
- Retention of jobs and value added
- Reduced criteria air contaminants (CAC) and greenhouse gas (GHG) emissions
- Defer or avoid new energy infrastructure
- Reduced impact on land and water
- Reduced resource use

The upstream oil and gas (UOG) sector is a significant contributor to Canada's energy consumption and greenhouse gas emissions. In order to gain insight into the energy use patterns and energy efficiency opportunities within the facilities that constitute the UOG sector in Canada, Natural Resources Canada's Office of Energy Efficiency (OEE) engaged Stantec Consultants and Marbek Resource Consultants Ltd. to undertake the study: "Energy Efficiency Potential in Canada's Upstream Oil and Gas Sector"

This draft report outlines the methodology, analysis and results of that study.

1.2 Study Objectives, Scope, and Deliverables

The primary objectives of this study are:

- To develop an energy use profile for Canada's UOG sector;
- To identify and evaluate energy efficiency opportunities to improve UOG sector usage and demand in different application areas; and
- To develop initial cost curves for these opportunities to estimate the technical and economic potential for energy efficiency in Canada's UOG sector.

The study examines energy efficiency potential in the UOG sector (a subsection of North

American Industry Classification - NAICS 2111[1]). This analysis covers the following sub-sectors:

- Natural Gas Production
- Natural Gas Processing (sweet gas)
- Natural Gas Processing (sour gas)
- Crude Oil Production and Processing (light and medium)
- Crude Oil Production and Processing (conventional heavy)
- Crude Oil Production and Processing (bitumen and synthetic)

The study addresses the following questions:

1. How much energy is consumed by the UOG sector by fuel type, sub-sector and process?
2. What opportunities exist for making the upstream oil and gas sector more energy efficient?
3. What is the potential for the future implementation of energy efficiency measures in the UOG sector and what would be the relevant energy and Greenhouse Gas (GHG) emissions-related impacts?

As further elaborated on in this report, the study was executed at the sub sector level to ensure a defensible, robust analysis. However, to maintain confidentiality requirements for the study's participating companies, the results are presented at an aggregate sector-wide level with further elaboration according to key energy end-uses.

1.3 Report Presentation

The remainder of the report is structured to present:

- The methodology and sector definition in Sections 2 and 3.
- The 2005 Base Year and Reference Case energy use profiles in Section 4.
- The energy efficiency and conservation best practices, and the technical potential for energy efficiency in Section 5.
- The Economic Potential scenario and the GHG emissions associated with the energy savings potential in Section 6.
- The implementation of energy management best practices in Section 7.
- The waste reduction best practices and their market penetration in Section 8
- Observations and conclusion, including a commentary on barriers to improving energy efficiency in the UOG sector, in Sections 9 and 10.

---

1 NAICS is a system for classifying industrial activities, in use in Canada, the US and Mexico.
NAICS 2111 - Oil and Gas Extraction This industry group comprises establishments primarily engaged in operating oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing and equipping wells; operating separators, emulsion breakers, desilting equipment and field gathering lines for crude petroleum; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. This industry includes the production of oil, the mining and extraction of oil from oil shale and oil sands, and the production of gas and hydrocarbon liquids, through gasification, liquefaction and pyrolysis of coal at the mine site. All activities covered in this study fall within this NAICS grouping, but the study does not cover the entire NAICS group of activities.

2.0 Methodology

2.1 Profiling Energy Use

A two-phase approach was used to fulfill the study objectives. In the first phase, an energy use profile for the UOG sub sectors and end uses was developed using a unique three-pronged methodology designed to generate a robust, transparent and useful baseline profile of energy efficiency at the level of individual facilities and subsectors as well as the entire UOG sector. The approach was designed to determine the market penetration level of energy efficiency measures, and, when data was available, the actual associated savings experienced in the field. The three aspects of this approach were:

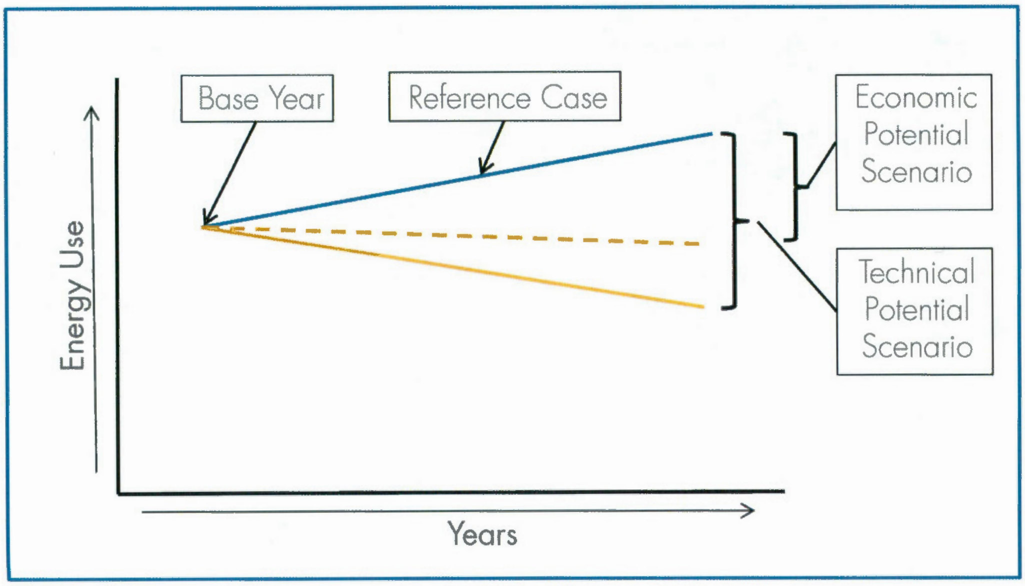
I. An energy use profile which was largely empirical in nature in that common energy use metrics were used to benchmark a population of facilities and to determine best practice according to various characterizations of "best in class" performance.

II. An examination of technical best practices (TBP) which addressed the technological potential to reduce energy use. For example, installing a heat recovery system on a process exhaust stream to pre-heat a feed stream, resulting in reduced process energy use. A TBP performance indicator was developed to show the total number of applicable TBPs that are implemented at a plant, subsector and sector levels.

III. An examination of management best practices (MBP) which addressed the behavioural aspects of reducing energy use. For example, having a policy and plan in place to manage energy. The MBP indicator is the total number of applicable management best practices that are implemented at a plant, subsector or sector level.

Both technical and management best practices benchmarks provide an indication of the market penetration levels of energy efficiency measures and practices. An analysis of the energy use profile together with the implementation rates of both TBPs and MBPs offers insights to the energy efficiency opportunities in these facilities.

Figure 1 - Generic Concept of Energy Potential Analysis



2.2 Analysis Steps

The analysis steps to determine the energy efficiency potential are described below:

- Step 1 - **Base Year Energy Use**: The base year is the starting point for the analysis and provides a detailed description of "where" and "how" energy is currently used in the upstream oil and gas (UOG) sector. In this study the Base Year is 2005.
- Step 2 - **Reference Case**: This is a projection of energy use to 2030, in the absence of any new energy efficiency market interventions after 2005 (i.e., accounting for what utilities and government have already planned for this period). The reference case is the baseline against which the scenarios of energy savings are calculated.
- Step 3 – **Energy Efficiency Opportunities (Best Practices)**: The best practices that result in energy reduction in the UOG sector are defined. These opportunities, or best practices, include technical best practices (TBP) and management best practices (MBP).
- Step 4 – **Base Year Implementation of Best Practices**: The market penetration rates of the best practices in the Base Year were determined through an energy benchmarking analysis. This analysis included a survey of UOG facilities to determine level implementation of best practices in the Base Year.
- Step 5 – **Technical Potential Scenario**: The technical potential scenario estimates the energy savings if all the technically feasible opportunities are implemented. The energy savings potential is an estimate of the gap between the market penetration rates in the Reference Case and the maximum savings if the UOG sector implements all the technically feasible opportunities.
- Step 6 – **Economic Screening of Best Practices**: The technical best practices are screened with an economic cost benefit test to determine which practices are economically feasible from a societal point of view. The economic cost benefit test used in this study is the Total Resource Cost (TRC) test. The TRC test and relevant parameters are summarized

in Appendix A.
- Step 7 – **Economic Potential Scenario**: The economic potential scenario estimates the level of savings that would occur if all the technical best practices that passed the economic benefit cost tests in Step 5, in this case the TRC test, are applied to the industry sectors.

The GHG emissions associated with the energy use was determined for the Base Year, Reference Case and Economic Potential Scenario at 5-year increments from 2005 to 2030.

2.3 Project Implementation

The energy efficiency performance benchmarking and the energy efficiency potential analysis are informed through the acquisition of primary data, and supplemented by secondary data to fill gaps. As such, the data collection and data analysis stages are key elements in the successful implementation of the study. The data collection and analysis comprised the following main areas:
- Industry recruitment
- Using a remote survey instrument to gather primary data from recruited facilities
- Data collection from secondary sources
- Filling the information gaps by seeking advice from subject matter experts

These areas are discussed in further detail below.

2.3.1 Industry Recruitment

Many of the companies in the UOG sector operate across many, or all, of the six subsectors identified for this study. Some companies are large multinationals, whereas others are intermediates or juniors with comparatively small asset bases and geographic focuses. There are exploration and development companies as well as energy trusts, which typically do little exploration and focus on 'harvesting' existing resources. The conditions under which oil and gas are found, and therefore the processes that must be used to extract the resources, differ considerably. The sector is therefore very heterogeneous. Based on research carried out for this project, the number of facilities in each UOG subsector from the inventory of UOG facilities is given in Figure 2 on the following page:

Figure 2 - Inventory of Canada UOG Facilities[1]

Sub Sectors	Number of Plants
NG Producers	25,198
NG Producers - Sweet	536
NG Processors - Sour	242
Light & Med Oil	15,697
Conventional Heavy	5,297
Bitumen	48

To try to ensure that a representative sample of company types and sizes, as well as subsectors, was included in the study, a variety of recruitment methods were simultaneously employed. The recruitment effort was extensive and included:

- Ensuring that industry was aware of the study and that industry representatives were included on the project Steering Committee.
- Developing recruitment material explaining the business case, the benefits of the study and the anticipated effort that would be required from each participant. This material was sent out under NRCan's banner to ensure the materials were not mistaken for 'spam' mail.
- Targeted recruitment through associations, such as CAPP, Small Explorers and Producers Association of Canada (SEPAC), and Canadian Heavy Oil Association (CHOA). CAPP's network included its Natural Gas Benchmarking Committee (encompassing 26 companies), Fuel Gas Committee, and Oil Sands Environmental Performance Working Group. This included both mass-marketing mailshots through association contact lists as well as direct presentations to specific audiences.
- Direct targeted recruitment of companies that had pre-existing working relationships with the project team. Recruitment followed a dual top-down and bottom-up approach, with senior-level executives as well as plant managers and corporate energy/environmental managers being directly contacted by the project team. This was intended to encourage both staff and managerial enthusiasm and will to allocate time and resources for the study, and to therefore help remove internal barriers to participation.
- Repeated follow up with companies and continuous assessment of the sample of participating companies to direct additional focus to sub-sectors that were underrepresented. The recruitment period was extended to try to ensure good facility

1 Based on the following sources of information: BC (Conversation with BC Oil and Gas Commission, 21st April 2009; AB (ERCB Facility List ST102, accessed 31st March 2009, with gas wells removed); SK (Government of Saskatchewan Energy & Resources Master Facility Report, accessed 3rd April 2009); MB (List of facilities provided by Manitoba Science, Technology, Energy and Mines on 7th April 2009); NU (CAPP Industry Across Canada: Nunavut report, accessed 6th April 2009); ON (Conversation with Ontario Ministry of Natural Resources, 9th April 2009); QC (Conversation with Direction du developpement des hydrocarbures, 8th April 2009); NB (Conversation with Minerals and Petroleum Development Branch, NB Department of Natural Resources, 7th April 2009); PE (CAPP Industry Across Canada: Prince Edward Island, accessed 6th April 2009); NS (Conversation with CNSOPB, 14th April 2009); NL (Conversation with CNLOPB, 27th April 2009); YK (Conversation with Chief Operations Officer, Government of the Yukon, 8th April 2009); NT (Conversation with Mineral, Oil and Gas Division, Government of Northwest Territories, 8th April 2009).

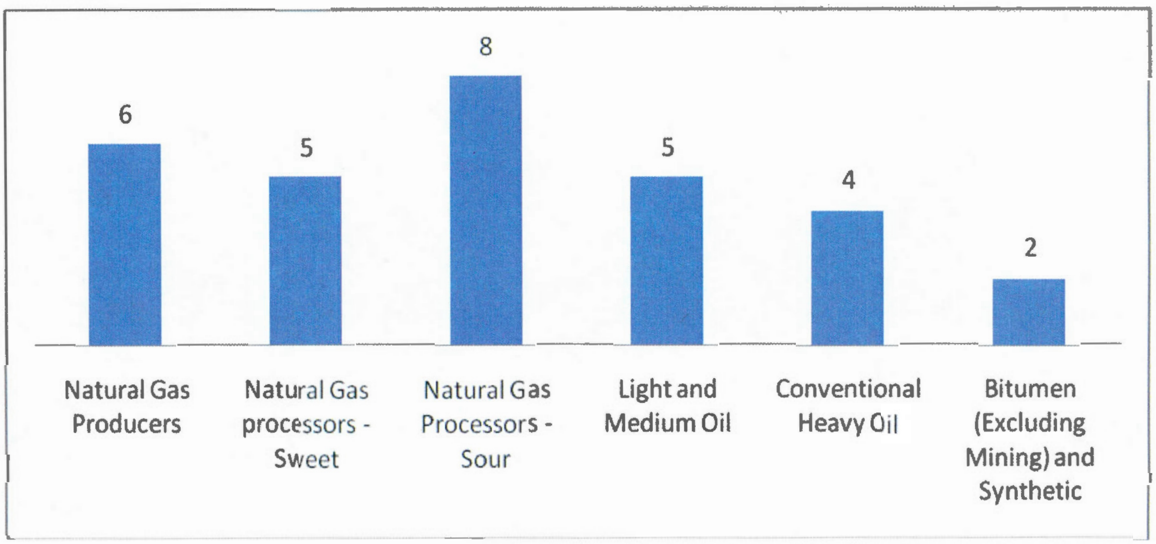
representation from all sub-sectors.

The target for recruitment in the study was 72 facilities – 12 from each sub-sector. Within the timeline and budget allocated for the study, this was identified as the most appropriate target to provide robust sector-wide analysis as well as confident sub-sector conclusions. Recruitment levels reached 49 facilities (68% of target) during August 2009, but subsequently a number of secured facilities were removed from the study, with companies citing a number of reasons for this action. In addition, many companies expressed an interest in the study, and support for its objectives, but nonetheless declined to take part. The main responses provided by companies for not participating or withdrawing (partially or fully) from the study were:

- Concern regarding how the study's information will be used, and belief that the information will be used by NRCan to simply increase regulation on the industry. Recent changes in the Alberta royalty structure and international pressures on the oilsands and Canada to reduce GHG emissions have contributed to this concern. The project team attempted to address these issues upfront through a) inclusion of the industry representatives on the Steering Committee b) clear communication to the potential participants stating the intent and purpose of the study when first approaching them and c) follow-up communications re-stating that Natural Resources Canada's intention was to try to help and not hinder industry. Nevertheless, this perception persisted and discouraged some companies from participation.
- Concern that the publicly-available information from the study, especially regarding the energy-intense sub-sectors such as bitumen, would be used by non-governmental organizations to attack the industry's environmental record.
- Due to the economic recession, voluntary initiatives were being accorded a low priority by management in favour of compliance with statutory regulations and a focus on operational priorities (such as maintaining production). Many companies were also reducing their workforce and for all these reasons resources were often not available to undertake surveys.
- Companies were undergoing mergers, acquisitions, layoffs and other structural changes, creating job uncertainty for key company staff and resulting in several companies placing a very low priority on allocating staff to participate in the study.
- Lack of information regarding energy use and management within the company and/or facility. Many companies noted that, due to a history of according energy management a low priority, records regarding energy consumption were incomplete and/or difficult to obtain. One company specifically noted that they were just putting a data management system in place and, had the study been scheduled for 2010 when the system was operational, they would probably have participated.
- During the transfer of properties associated with acquisitions and divestments data on energy consumption and conservation efforts is often lost.

The recruitment effort by the project team was considerable, but due to the need to complete the study before the end of 2009, recruitment had to be curtailed even though the target number of participants was not reached. In total 30 facilities, representing 15 companies, participated in the study and the number of participating facilities per subsector is presented in Figure 3.

Figure 3 - Number of Plants by Sub-Sector



Although the recruitment target was not met, the companies engaged in the study do provide a good mix of types, with 6 majors, 5 trusts and 4 intermediate/junior companies participating. Thus within the results there is a good cross section of companies that have varied developmental and financial approaches to the production and processing of oil and gas in Canada. The sample of 30 facilities is still a substantial number from which to draw confident conclusions at the sector level about the energy efficiency potential of the UOG sector. However, at a sub-sector level, due to the low number of facilities (particularly in the conventional heavy and bitumen sub-sectors) the results should be treated with more caution. However, the project team did note that similar patterns were evident in the responses from facilities within the same sub-sector, which indicates that results may be reasonable for most sub-sectors. Nevertheless, additional research is recommended to confirm the results of this project at the sub-sector level.

2.3.2 Data Collection from Recruited Facilites

Companies recruited into the study project were sent remote survey instruments to complete. A Technical Best Practices and a Management Best Practices survey were sent to each facility; in addition, a corporate Management Best Practices survey was sent to a corporate contact. The survey instruments were designed to collect information on the current energy consumption by fuel type and end-use at each facility, as well as the implementation of energy efficiency best practices and the reasons for not implementing further measures.

A pilot version of the survey instrument was tested on-site with one company to ensure that the survey instrument is user-friendly and the collected data is accurate and representative of the conditions at the plant. Additional pilot surveys were conducted remotely. The feedback from the pilot phase was used to improve the survey instruments in terms of both clarity and coverage.

Once data was collected, it was checked by the project team to ensure the information provided was complete and consistent. The project team followed up with the facilities or companies where necessary. A facility report card was produced for each facility, outlining the key output from the surveys.

2.3.3 Data Collection from Secondary Sources

Besides the primary data and the resources to develop the best practices profiles, the study also required secondary data and input from external sources as summarized in Figure 4.

Figure 4 - Elements Informed by Secondary Sources

Element	Source	Applicable Section with Detailed References
Base Year 2005: Total energy use by sub-sector and supplementary data for energy end use profiles.	• Statistics Canada • National Energy Board • NRCan Outlook – Reference Case 2006	Section 4
Reference Case: Projected energy use by sub-sectors from 2010 to 2030.	• National Energy Board • NRCan Outlook – Reference Case 2006	Section 4
Energy conversion factors	• National Energy Board • Statistics Canada • Union Gas	Sections 4, 5, 6 Appendix B
GHG emission factors	• Environment Canada	Section 6

2.3.4 Filling the Survey Information Gaps

When applicable, the gaps in information from the surveys were filled by contributions from UOG expert members of the project group. The consultations provided additional information on the following areas:

- The applicability of technical best practices to various subsectors
- Energy use profile of UOG specific processes
- Energy profiling of end uses

3.0 Upstream Oil & Gas Sub-sector Profile

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

3.1 Sub-sectors Definition

The project scope focuses on the production and processing of crude oil and natural gas in Canada. The majority of the production occurs in Alberta but other provinces like British Columbia, Saskatchewan, Newfoundland and Nova Scotia have significant production. Smaller scale production also occurs in the North West Territories, Yukon, Manitoba and Ontario. The scope of the project does not include oil and gas exploration activities, drill rig facilities or pipeline facilities. For clarity, note also that refining is excluded (this is a downstream activity). For the purpose of this study the UOG sector is divided according to the following six sub-sectors:

- **Natural Gas Producer:** The facilities included in this sub-sector produce either sweet or sour gas, and include gathering systems, compressor stations and storage facilities. The size of these facilities varies greatly from one site to another. The facilities use mainly fuel gas, natural gas or electricity. Solar photovoltaic panels are sometimes used to provide power for remote locations.

- **Natural Gas Processing Sweet:** The facilities included in this sub-sector process gas that is less than 0.01 % hydrogen sulphide (H2S). The inlet gas is dry or wet sweet gas and the plant may or may not recover C2, C3, and C4+. The sizes of these facilities vary greatly from one site to another. The energy used is mainly fuel gas, natural gas, and electricity. Some of these facilities also use their fuel gas to generate their own power.

- **Natural Gas Processing Sour:** Sour gas plants are usually large facilities. Within these facilities, the sour gas is sweetened, and then any remaining sour gas is flared, re-injected into a reservoir or recovered. The process involved in sulphur processing is energy intensive. The energy used is mainly fuel gas, natural gas, and electricity. Some of these facilities generate their own power with waste heat from the sulphur recovery process and fuel gas.

- **Crude Oil Light and Medium:** The facilities included in this sub-sector produce oil with an American Petroleum Institute (API) gravity higher than 25.72 or a density lower than 900 kg/m3. Some facilities use Enhance Oil Recovery (EOR) techniques, such as water flood and reinjection, to produce the oil. The sizes of these facilities vary greatly from one site to another. The energy used is mainly fuel gas, natural gas, and electricity.

- **Crude Oil Conventional Heavy:** The facilities included in this sub-sector produce oil with an API gravity lower than 25.72 or a density higher than 900 kg/m^3. Some facilities will use EOR techniques, such as System Assisted Gravity Drainage (SAGD), to produce heavy oil. The size of these facilities vary greatly from one site to another. The energy used is mainly fuel gas, natural gas, and electricity.

- **Crude Oil Bitumen:** The facilities included in this sub-sector produce oil which does not flow to a well in their naturally occurring state. In-situ production methods, such as Cyclic Steam Stimulation (CSS) or SAGD, are required to produce bitumen. Bitumen processing is an energy intensive process. The energy used is mainly fuel gas, natural gas, and electricity. Bitumen processing plants are usually large facilities and cogeneration of electricity and heat has a good penetration in the sub-sector.

3.2 Coverage Of Energy Supply

The energy efficiency potential analysis addresses the most common forms of energy used by the facilities in the UOG according to the following energy supply categories:
- Electricity
- Natural gas (pipeline quality)
- Fuel Gas (producer consumption)
- Refined Petroleum Products (RPP)[1]
- Other unrefined products

The energy content conversion factors used are summarized in Appendix B.

The survey results revealed that use of RPP and other refined product use in process equipment was negligible. Therefore RPP use in process equipment was not included in the potential analysis.

Industry feedback obtained during the survey pilot phase confirmed the importance of produced water during as a factor affecting energy consumption. Many oil reservoirs in Canada are water driven meaning that pressure in the reservoir is maintained by natural occurring water below the oil baring zone or by the injection of water into the reservoir for secondary and tertiary oil recovery methods. Facilities that are required to handle large amounts of produced water have higher energy intensities. Equipment such as free water knock-out and oil treater vessels which require fuel gas and electrostatic grids to separate the oil from the water are used. The produced water is then stored in skim tanks to remove more oil prior to being injected back into the reservoir or disposal wells using engine and motor driven pumps. Therefore additional amounts of fuel gas and electricity are required to produce a barrel of oil.

1 For example, heating oil, propane, LPG, etc.

The amount of annual water produced was therefore also included as a performance indicator in the technical analysis. However, due to the limited number of surveys reporting the quantity of produced water, the collected data was not used in any qualitative or quantitative analysis. For the facilities who reported their produced water, water intensity (m3/boe) was calculated and included in the facility report card – to maintain confidentiality, this information is not included further within this report.

3.3 GHG Emission Factors

Data from Environment Canada[2] was used to calculate the facility GHG emissions. The GHG emission factors are given in Figure 5 and Figure 6. A quantitative analysis of GHG savings associated with venting and flaring was not included in the scope of the study..

Figure 5: GHG Emission Factors For Natural Gas And Fuel Gas

	CO_2 Factor	GWP	CH_4 Factor	GWP	N_2O Factor	GWP
	g/m3	CO_2	g/m3	CH_4	g/m3	N_2O
Pipeline quality natural gas	1891	1	1.9	21	0.05	310
Fuel gas (Producer Consumption)	2398	1	6.5	21	0.06	310

Figure 6 - GHG emission factors for natural gas, fuel gas and electricity in CO2e/GJ

Energy Type	Tonne CO2e/GJ
Pipeline quality Natural Gas	0.0515
Fuel Gas	6.546E-05
Electricity*	0.245
* or 900 g/kWh	

As the model developed is not geographically-specific, a single electricity GHG emission factor was used. The emission factor is that for Alberta, where the majority of facilities are located. However, as the emissions intensity of electricity in Alberta is the highest in Canada (due to its reliance on coal-fired generation) the actual GHG impacts expected from the implementation of energy efficiency opportunities may be lower than suggested by this study.

2 Environment Canada (2006). 2006 National Inventory (Annex 12, Table A12-1)

3.4 End Uses

3.4.1 Energy End Uses

The energy efficiency potential analysis considers energy use at the end use level, as profiled in Figure 7.

Figure 7: End Uses

End Use Categories		
Generic	Heating	Direct Process Heating
	Cooling	Refrigeration Compressors
		Condensers/ Coolers
	Drivers	Engines
		Gas Turbines
		Motors
	Rotors	Gas Compressors
		Air Compressors
		Pumps
		Fans/ Blow ers
Process	Gathering Systems	
	Glycol Dehydrators	
	Desiccant Dehydrators	
	Fractionation	
	Sulphur Recovery	
	Tail Gas Incineration	
	Acid Gas Injection	
	Oilfield Pumping	

The end uses are divided into generic and process specific end uses. It should be noted that the process end uses are those processes that are subsector specific. The generic end uses are divided into the following categories:

- Process Heating: The end use includes all direct fired heaters and steam boilers.
- Process Cooling: Refrigeration compressors and coolers are included in the end use.
- Drivers: The end use includes all equipment that is used to put fluid movers in work and is sub-divided into engines, gas turbines and motors (for example, motors used in oilfield pumping).
- Rotors: Systems that move fluids and are driven by a motor or engine. This category includes compressed air systems, pumps and fans/blowers.

Examples of subsector specific end uses include: gathering systems, gas dehydration, sulphur recovery, tail gas incineration, oilfield pumpjacks, and fractionation.

Note that incineration could not be included within the modeling framework used to develop the energy efficiency potential scenarios. This would require a more detailed model including both mass and energy balances that would allow a quantitative analysis of two streams: the process stream and any fuel added to enable complete combustion. The potential savings from incineration were estimated outside the modeling framework and are included in Section 5.4. The savings are estimated based on technical feasibility only.

Due to the relatively small energy use by comfort heating and cooling, lighting, and transportation (indoor and outdoor), these end uses are excluded from the analysis[3].

3.4.2 End Uses and Activities Related to Waste Reduction

lWaste reduction initiatives are particularly important in the natural gas production and processing subsectors but also have significance in the rest of the UOG sector. The reduction of waste, whilst not generally considered within the framework of energy efficiency, does have impacts in terms of increased production and reduced GHG emissions. As such, waste reduction opportunities can result in improved energy intensities (e.g. energy per unit of production) and emissions intensities (e.g. emissions per unit of production). For these reasons, the Steering Committee specifically requested that waste reduction opportunities be included within the scope of the study. The relevant activities are defined under a Waste Reduction end use, and summarized in Figure 8.

Figure 8: List Of Waste Reduction End Uses And Activities

End Use or Activity	
Waste Reduction	Flaring
	Pipelines
	Tanks
	Valves
	Wells
	Compression – Methane Savings
	Natural Gas Dehydrators – Methane Savings
	Chemical Injection Pumps
	LDAR Program

3 In the project team's experience, typically less than 10% of energy used at a UOG facility is consumed by these end-uses.

4.0 Base Year and Reference Case Energy and GHG Emmissions Profile

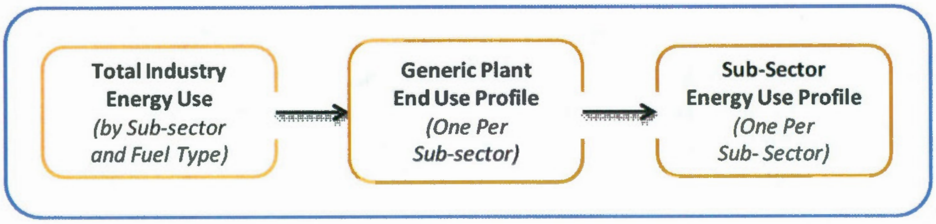
4.1 Base Year

The 2005 Base Year energy use profile provides an estimate of how the UOG sector energy consumption is currently distributed by fuel type, sub-sector, and end use. The relevant assumptions and information applied to develop the Base Year energy use profile and a summary of the results follows.

4.1.1 Base Year Methodology

The 2005 Base Year energy use profile by sub sector is developed with a top-down approach where the total sub-sector energy use is proportionally allocated to the end uses based on the calculated energy use distribution of a generic plant that was developed for each subsector. The total UOG sector energy use in the 2005 base year is based on energy use and production data from NRCan (2006) and the National Energy Board (NEB, 2009) (Appendix C).

Figure 9: Approach To Develop Sub-Sector Energy Use Profiles



As illustrated in Figure 9 the proportional allocation of the total energy use is based on a generic plant end use profile, which is sub-sector specific. Figure 10 illustrates how a Base Year sub-sector energy use profile is developed by disaggregating the total sub sector energy use, using a generic end use profile. Generic plant profiles and energy end use profiles of all six sub-sectors are presented in Appendix D.

Figure 10: Example Templates Illustrating Development Of Sub-Sector Energy Use Profile.

Total Sub-sector Energy Use in GJ

	Electricity	Natural Gas	Fuel Gas
End Use			

Generic Plant End Use Profile in %

End Use	Electricity	Natural Gas	Fuel Gas
Direct Fired Heaters / Steam Boilers			
Refrigeration Compressors			
Engines/ Gas			
Motors			
Air Compressors			
Pumps			
Fans/Blowers			
Gas Compressors			
Incinerators			
TOTAL			

Sub-sector Enenrgy Use Profile in GJ

End Use	Electricity	Natural Gas	Fuel Gas
Direct Fired Heaters / Steam Boilers			
Refrigeration Compressors			
Engines/ Gas			
Motors			
Air Compressors			
Pumps			
Fans/Blowers			
Gas Compressors			
Incinerators			
TOTAL			

The UOG sub-sector specific generic plant profiles were developed using the following steps:

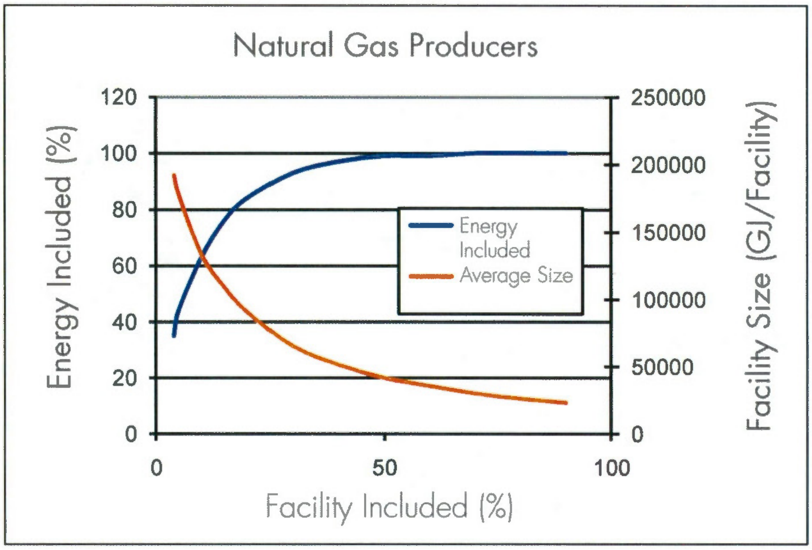
- Draft subsector energy end use profiles were constructed using weighted averages of the energy balances developed for each of the 30 participating plants weighted by type and quantity of energy consumed by the end use. Due to the limited number of surveys, there was not enough information to construct separate generic plant models for small, medium and large facilities, separately. Therefore, a single facility size per subsector was considered. This led to a mismatch between the resulting generic plant size and the size of the surveyed facilities. The mismatch was particularly pronounced for Natural Gas Producers, Light and Medium Oil, and Conventional Heavy Oil subsectors, where the calculated generic facility size was found to be an order of magnitude or more smaller than the surveyed facility sizes. Assumptions made to match the generic plant size to the sizes of the surveyed facilities for these three subsectors, as follows.

To determine the size of the generic plants the following steps were used:

- The number of Canadian plants in each subsector was compared to the energy use[1] by facilities and it was determined that in each subsector about 15-20% of the plants account for 80% of the energy use. As shown in the Figure 11, the small and micro facilities represent a very large number of facilities, but accounts for less than 20% of the energy use. To manage the analysis within the scope and budget of the study, the study focused on the medium and large facilities that account for 80% of the energy use.

1 Based on real energy consumption data for the UOG sector obtained by the project team, representing several years' worth of data for several companies

Figure 11: Cumulative Subsector % Energy Use A Function Of Facility Size And Number



- The generic plant energy use was determined by estimating the energy use for the large and medium sized facilities. The estimated number of medium and large facilities in each subsector is summarized in Figure 12.

Figure 12: Estimated Number Of Medium And Large Facilities by Sub-sector

Sub-sector	Number of Plants	Percentage Included	Plant Energy Use Lower Threshold (GJ)
NG Producers	3,780	15%	110,000
NG Processors - Sweet	536	100%	-
NG Processors - Sour	242	100%	-
Light and Medium Oil	3,924	25%	55,000
Conventional Heavy	742	14%	8,400
Bitumen	48	100%	-

- The energy end use profiles were reviewed by UOG experts on the team and compared to the team's extensive database of facility's energy use.
- Minor adjustments were made to the end use profiles to ensure the profiles were representative as generic sub-sector plants.

4.1.2 Base Year Energy Use

The 2005 Base Year Energy Use Profile for the UOG sector is presented in Figure 13. In 2005 Canada's six UOG sub-sectors used an estimated 800 PJ of energy (NEB, 2009; NRCan, 2006). As illustrated in Figure 13, natural gas, fuel gas and electricity respectively accounted for 39%, 53% and 6% of the total energy use. The energy use by sub-sector is illustrated in Figure 14 and the detailed values are summarized in Appendix D. The profile of energy use by fuel type, such as the proportional use of natural gas and fuel gas, is informed by the survey results.

Figure 13: 2005 Base Year Energy Use By Fuel Type (PJ)

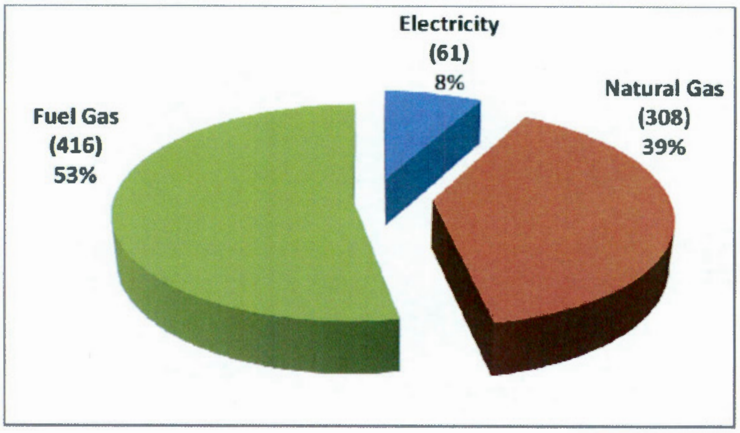
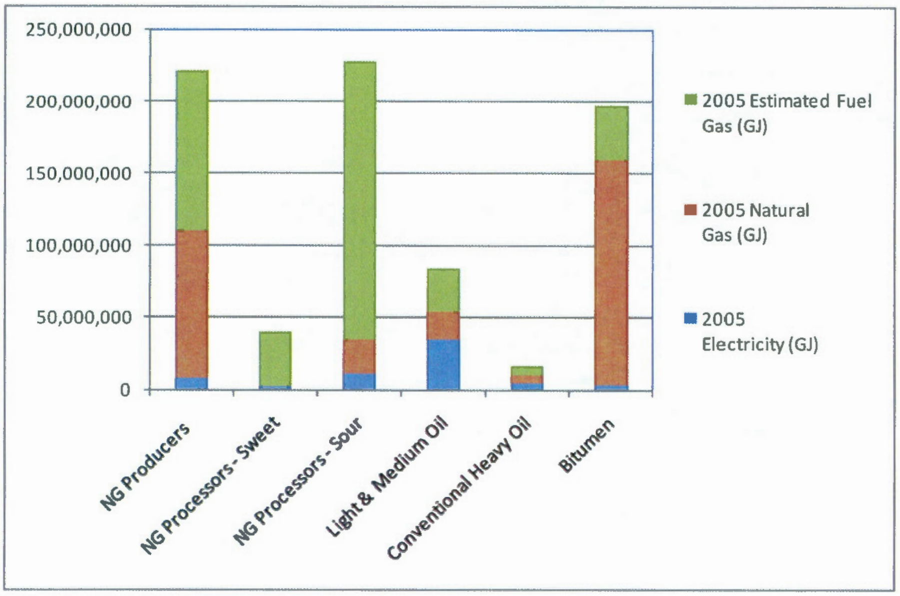


Figure 14: 2005 Base Year Energy Use By Sub-Sectors (Excluding RPP) (GJ)

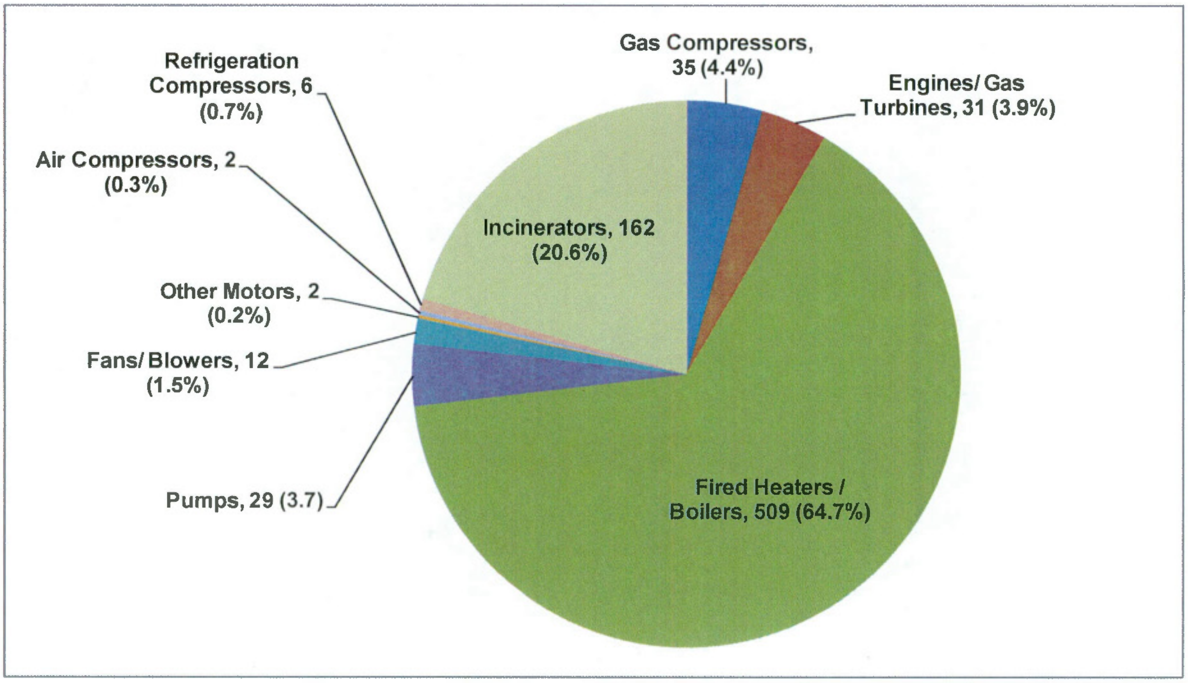


The three most energy intensive sub-sectors, Natural Gas Producers, Natural Gas Processors – Sour, and Bitumen account for close to 82% of UOG sector energy use. The energy use allocated to the sweet and sour processing are mainly informed with data obtained through the survey which included 5 sweet gas and 8 sour gas facilities. Due to the relatively small sample size one can expect a degree of inaccuracy in the allocation, which will need to be addressed in future studies.

4.1.3 Base Year Energy Use by End Use

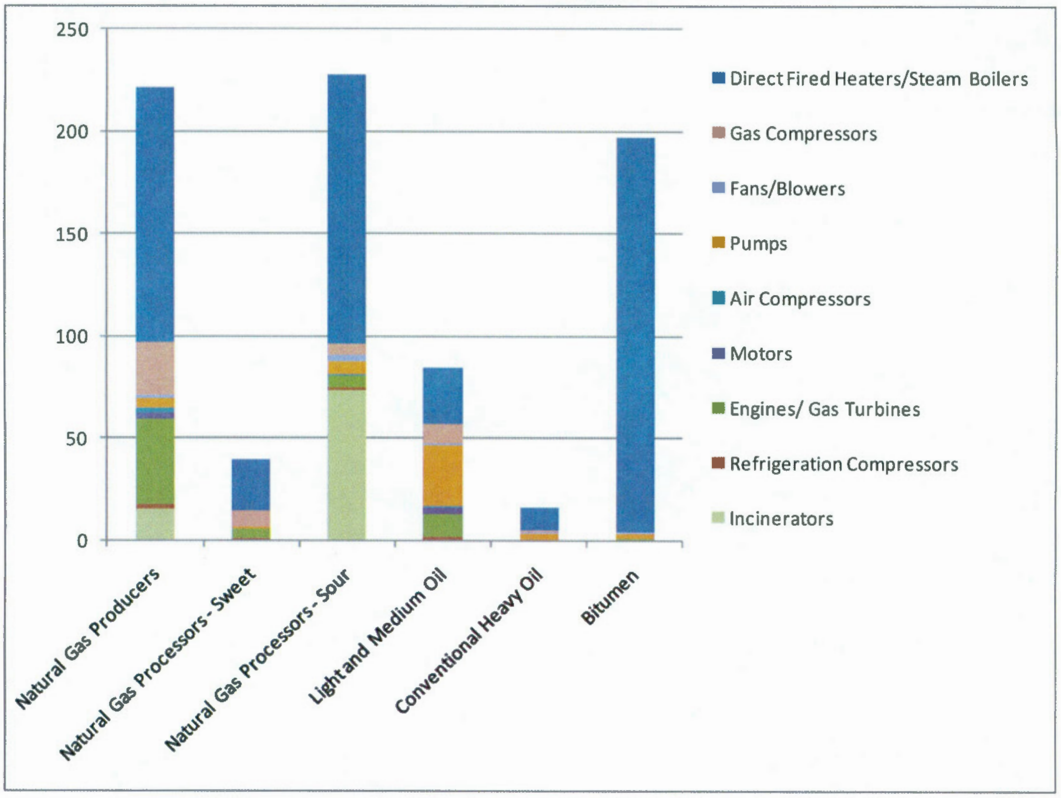
The 2005 Base Year energy use by end uses for the total industrial sector is illustrated in Figure 15. This information was obtained from the surveys. The participants were asked to list the type and amount of energy used by the facility's main end uses in 2005 and 2008, as it was anticipated that many of the facilities may not have reliable data for 2005 or may not have been in operation in 2005. The outcome of the surveys confirmed the lack of reliable 2005 data. Therefore, 2008 data was used to calculate the percentage of energy use by end use for the Base Year. Close to 65% of the energy is used by industry for process heating (direct fired heaters and steam boilers), while incinerators account for close to 21%.

Figure 15: 2005 Base Year Energy Use By End Use In PJ, Excluding RPP



The energy use by end use for each sub-sector is presented in Figure 16. The detailed tables for each sub sector are provided in Appendix D. The end use profile highlights the relevant dominance of the direct fired heating in Natural Gas Production, Natural Gas Processing – Sour and Bitumen subsectors, relative to the other end uses and sub-sectors.

Figure 16: 2005 Base Year Energy Use By End Use And Sub-Sector (PJ)



4.2 Reference Case

The Reference Case provides a projection of energy use to 2030, in the absence of any new energy management market interventions after 2005 (i.e., based only on what utilities and government have already planned for this period). The Reference Case is the baseline against which the scenarios of energy savings are calculated.
The assumptions and information applied to develop the Reference Case energy use profiles and a summary of the results follows.

4.2.1 Reference Case Methodology

The study does not include the development of energy use forecasts, and relies on existing forecasts to develop the projected energy use in the Reference Case.

The production forecast for crude oil and natural gas resources from the NEB[2] was used to

2 National Energy Board (2009). Reference Case 2009.

derive the energy use breakdown between subsectors for the Reference Case milestone years, calibrated to NRCan's[3] energy use forecast up to 2020. The NEB crude oil and natural gas production forecast was also used to extrapolate the energy consumption values from 2020 to 2030.

The market penetration rate of technical best practices was assumed to be 1% per year based on long term industrial data and audit results in the project team's possession.

4.2.2 Reference Case Energy Use

The Reference Case total energy use is estimated to increase by about 47% from 2005 to 2030 as illustrated in Figure 17, Figure 18 and Figure 19. In absolute terms the increase is close to 374 PJ. The largest increase in energy use is associated with Bitumen subsector which is expected to triple between 2005 and 2030 as more natural gas is required for increases in bitumen production and upgrading during this period. The second largest growth is predicted for the light and medium oil subsector which is expected to double its consumption of energy during the same period as more energy intensive enhance oil recovery technologies are implemented and more water is handled per unit of oil produced. The Conventional Heavy oil subsector is predicted to show a small growth. The natural gas production and processing subsectors, by contrast, are expected to show a decline in their energy use: many sour gas processing plants are seeing their feed stream becoming more sweet thus requiring less energy. In addition, gas reservoirs are being depleted resulting in less gas being handled – however, this reduction in absolute energy usage is being somewhat offset by increases energy intensity due to increased field and plant compression as reservoir pressures reduce.

The increase in total energy is driven primarily by the increase usage of natural gas in the bitumen and fuel gas in the light and medium oil subsectors.

Figure 17: Reference Case Energy Use By Energy Source (PJ)

Energy Source	2005	2010	2015	2020	2025	2030
Natural Gas	308	361	473	579	601	623
Electricity	62	72	84	94	96	98
Fuel Gas	417	378	402	427	433	439
Totals	786	812	958	1,100	1,130	1,160

3 Natural Resources Canada (2006). NRCan Outlook – The Reference Case 2006

Figure 18: Graphic Representation Of Reference Case Energy Use By Energy Source (PJ)

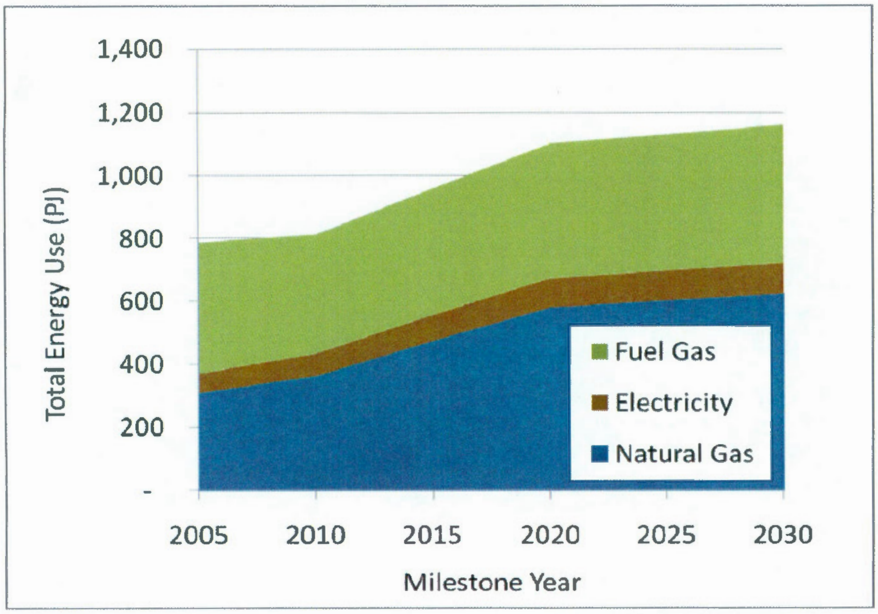


Figure 19: Reference Case Energy Use By Sub-Sector (PJ).

Sub-sector	2005	2010	2015	2020	2025	2030	Increase (2005 to 2030)
NG Producers	221	185	180	180	180	181	-18%
NG Processors - Sweet	40	31	30	29	28	28	-29%
NG Processors - Sour	228	180	171	164	163	162	-29%
Light & Med Oil	84	115	138	160	164	169	100%
Conventional Heavy Oil	16	18	19	18	18	17	9%
Bitumen	198	282	420	550	576	603	205%
Total	786	812	958	1,100	1,130	1,160	47%

5.0 Technical Potential for Energy Efficiency

5.1 Methodology

5.1.1 Identifying and Defining Energy Efficiency Opportunities

Industrial energy efficiency best practices were identified and informed using secondary sources, and Marbek and Stantec's extensive databases, which were developed with input from industrial experts and previous project data. The secondary sources include literature, equipment suppliers, and industry energy management experts[1]. A full list of references used is included at the end of this report.

Only TBPs that are technically feasible and commercially available are included in the analysis Leading edge technologies still at the pilot or concept stages were not included – however, participants were asked, as part of the MBP surveys, whether or not they were receptive to piloting cutting edge technologies. Of the thirteen companies that returned an answer, only one answered "yes"; four answered "partially"; eight answered "no".

A total of 78 energy efficiency TBPs were identified from the literature review. In order to manage the survey instruments within the budget of the project, and to ensure focus, this list was screened using three criteria:

- energy reduction potential (i.e. measures that could save a larger proportion of energy were favoured);
- ease of implementation (i.e. measures that could quickly and simply be implemented were favoured), and;
- applicability to subsector (i.e. measures that applied to multiple subsectors were favoured).

Only the top rated 46 TBPs were selected to be included in the assessment. The lists of included and excluded TBPs were presented to the Steering Committee, and subsequently the list of TBPs was refined, finalized and approved by the Steering Committee.

Technology profiles were developed for each TBP to provide required input parameters for the energy efficiency potential analysis modeling. These parameters include:

- The capital, and operating and maintenance costs.
- The life of the best practice, also referred to as the measure life.
- The energy savings of the best practice.

A complete set of technology profiles is included in Appendix H.

1 Including conversations with MEG Energy, Vanguard Engineering, OilPro Oilfield Production Equipment Ltd and Questor Technology Inc.

5.1.2 Benchmarking the Implementation of Opportunities

The extent to which best practices are currently implemented in industry (also referred to as the 'market penetration rate') was determined through an energy performance benchmarking approach. For each best practice the results from the benchmarking assessment provide information to define the Base Year market penetration rate and the opportunity that still remains for increased implementation.

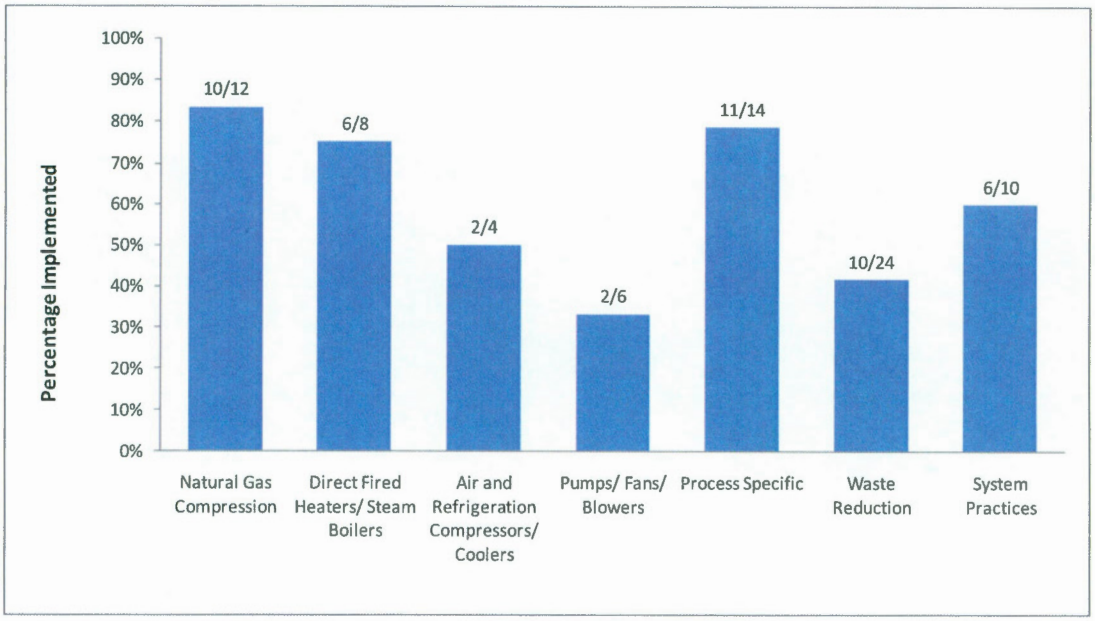
A scoring system was used to convert the information submitted by the plants on the TBP surveys into implementation rates. For example, the response to each TBP was given a score, using the following system when the best practice is either present or not:

- Applicable technical best practice implemented in facility (yes): score = 1
- Applicable technical best practice not employed (no): score = 0

In case where the best practices can be partially implemented a 3-level scoring system was used. A total score was calculated and each practices received an equal weight. For the TBPs, the scores are determined for each end-use of energy at the facility level as described in the previous section and the scores are further aggregated for the entire sub-sector.

30 Plants participated in the energy performance benchmarking through remote survey. A sample survey score chart is shown in Figure 20.

Figure 20: A Sample TBP Survey Score Chart



5.1.3 Modeling Technical Potential

Based on the market penetration rates of best practices in the Reference Case, the remaining amount of best practices that can still be implemented is determined. The Technical Potential energy savings are calculated as the savings from implementing all the technical best practices from the Reference Case market penetration rates to full market penetration rates. For replacement technologies the implementation occurs at the natural turn over rate of the equipment, while retrofit equipment is assumed to be fully implemented at the first milestone year, which is 2010[2]. Operation and maintenance measures are assumed to be implemented at their prescribed frequency.

5.2 Technical Best Practices

Technical best practices are production systems, equipment, methods and employed practices that result in advanced levels of energy user performance. The TBPs included in the study are listed in Figure 21, while the technology profiles with descriptions are included in Appendix F.

2 It is assumed for the purposes of modeling the Technical Potential, that there are neither economic nor practical barriers to implementing retrofit measures at the first available opportunity.

Figure 21: List of TBP for the UOG sector

End Use	Measure Name
Generic	
Pumps	Pump selection in lead/lag or primary/secondary set ups
Fans and blowers	Two speed motors or variable speed drives
	Fan housing and air flow improvements and hub bells installed
Engines	Improved performance monitoring, optimization and servicing practices
	Improvement of engine operation (e.g. lean burn in gas engine, fuel control)
Gas compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.
	Set valve positions to run compressor at optimum efficiency and reduce bypass (process suction pressure valve, bypass valve, backpressure control valve)
	Right sizing to minimize recycling of gas and match inlet gas volume
	Volume pocket adjustments - manual or automatic to match inlet gas stream
	Set cylinder clearance to a minimum to optimize compressor efficiency
	Inlet and interstage cooling
Air compressors	Annual air leak detection and repair program
	Intake air temperature reduction
Gas turbines	Improved performance monitoring, optimization and servicing practices
	Utilization of waste heat from exhaust (e.g. Waste heat recovery for use in other parts of the plant, heat transfer to heat transfer fluid, and transport around plant, augment heat by auxiliary firing where needed)

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

End Use	Measure Name
Fired Heaters / Boilers	Improved design practices and conversion from natural draft to forced air systems.
	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners
	Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers
	Line heater operating practices (seasonal)
	Boiler blowdown optimization
	Installation of economizer
	Use of energy efficient fired heaters (burners) with improved controls
	Oil treater temperature control to avoid over heating and over treating
	Annual steam trap surveys and repair
Refrigeration	Use sub-cooler (with proper O&M practices) to increase percent liquid entering chiller, thereby reducing refrigeration load
	Improve insulation to ensure at least 90% of insulation in very good condition
Condensors / coolers	Optimized automated condenser control (incl. temperature monitoring and fan pitch adjustment).
Process Specific	
Gathering Systems	Improved gathering systems - optimum pipe diameter, flow, pressure
	Perform pigging to remove wax build up from the pipe walls in oil gathering systems
	Hydrate formation mitigation is evaluated based on cost and emissions (e.g. Methanol can de injected into pipelines as an alternative to using line heaters to inhibit hydrate formation)
	Introduce site measurements to improve energy efficiency (e.g. SCADA system)
Glycol Dehydrators	Control system in place to monitor inlet gas volumes and glycol circulation rate

End Use	Measure Name
Desiccant Dehydrators	Timely replacement of desiccant dehydrators (replace glycol dehydrator with desiccant dehydrator)
Fractionation	Fractionation unit evaluated and monitored to ensure good performance (Minimize reflux via proper control system and/or tuning)
	Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins (e.g. high pressure spray, etc)
Sulphur Recovery	Optimize SRU performance (e.g. Optimum stack top temperature, integration with surrounding units)
Tail Gas Incineration	Determine optimum incinerator operating conditions and run Incinerator at these conditions to reduce incinerator temperature and oxygen levels to optimum levels.
	Use of high efficiency incinerators (e.g. Questor incinerators)
	Use of high efficiency vortex burners
Acid Gas Injection	Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.
Oilfield Pumping - pumpjacks, PCP, ESP	Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing
	Perform routine testing and correction of abnormalities e.g. drive belt and rod string conditions, fluid levels in casing, pump off controllers, pump rod packing, pump position (bottoming), condition of electrical equipment (capacitors, breakers, ...)
System	
Electrical systems	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance
	Power factor > 95%
Controls	**Up-to-date DCS or PLC controls to optimize equipment run times and rates**

Figure 22: Breakdown of Sub-sector Specific Processes by Generic End Uses and Fuel Type

Process	End Use	End Use Application	% Energy Use By Fuel/Electricity		
			% Fuel Gas or Natural Gas	% Electricity	Total
Gathering Systems	Pump	For oil and water gathering	20	80	100%
	Compressor	For gas gathering	95	5	100%
Dehydrators	Fired Heater	Glycol Reboiler	100		100%
	End Use 2 (Pump)	Used to circulate glycol	50	50	100%
Fractionation	Fired Heater		100		100%
	End Use 2 (Pump)	Used to circulate hot oil and product	10	90	100%
Sulphur Recovery	Fired Heater	Auxiliary boilers	100		100%
	Pump	sulphurtransfer	50	50	100%
	Blowers	Steam or motor driven	50	50	100%
Oilfield Pumping - Pumpjacks	Engine or Electric Motor		20	80	100%

5.3 Implementation Of Technical Best Practices

The implementation of technical best practices (TBP) in Canada's UOG sector by sub-sector is presented in Figure 23 to Figure 28, based on the results from the surveys[3]. Some best practices have an implementation level of 95% or higher and can therefore be regarded as a standard practices in the relevant subsectors. A list of these practices is summarized in Figure 29. These practices are not included in the energy efficiency potential analysis for these sub-sectors.

3 Note that 'N/A' in these figures indicates that the measure has no implementation in this sub-sector, not that it is not feasible.

Figure 23 - Implementation of TBP in Natural Gas Producers Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		13%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	29%
Cooling and Refrigeration	Refrigeration Compressors	17%
Drivers	Engines/ Gas Turbines	61%
	Motors	N/A
Rotors	Air Compressors	33%
	Pumps	72%
	Fans/Blowers	9%
	Gas Compressors	82%

Figure 24: Implementation of TBP in Natural Gas Processors (Sweet) Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		33%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	36%
Cooling and Refrigeration	Refrigeration Compressors	53%
Drivers	Engines/ Gas Turbines	40%
	Motors	N/A
Rotors	Air Compressors	40%
	Pumps	36%
	Fans/Blowers	2%
	Gas Compressors	56%

Figure 25: Implementation of TBP in Natural Gas Processors (Sour) Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		53%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	57%
Cooling and Refrigeration	Refrigeration Compressors	75%
Drivers	Engines/ Gas Turbines	47%
	Motors	N/A
Rotors	Air Compressors	69%
	Pumps	81%
	Fans/Blowers	50%
	Gas Compressors	69%

Figure 26: Implementation of TBP in Light and Medium Oil Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		44%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	41%
Cooling and Refrigeration	Refrigeration Compressors	N/A
Drivers	Engines/ Gas Turbines	51%
	Motors	100%
Rotors	Air Compressors	100%
	Pumps	70%
	Fans/Blowers	N/A
	Gas Compressors	60%

Figure 27: Implementation of TBP in Conventional Heavy Oil Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		34%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	25%
Cooling and Refrigeration	Refrigeration Compressors	N/A
Drivers	Engines/ Gas Turbines	45%
	Motors	63%
Rotors	Air Compressors	44%
	Pumps	19%
	Fans/Blowers	2%
	Gas Compressors	34%

Figure 28: Implementation of TBP in Bitumen Sub-sector

End Use Category	End Use	2005 Average Market Penetration Rate
System		67%
Direct Process Heating	Direct Fired Heaters/Steam Boilers	54%
Cooling and Refrigeration	Refrigeration Compressors	2%
Drivers	Engines/ Gas Turbines	2%
	Motors	N/A
Rotors	Air Compressors	26%
	Pumps	18%
	Fans/Blowers	50%
	Gas Compressors	26%

Figure 29 - List of TBP Considered Standard Practice by Sub-sector (excluded from the energy potential analysis)

Sub-Sector	Enduse	Measure
NG Producers	Rotors	Gathering Systems - Hydrate formation mitigation is evaluated based on cost and emissions
		Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.
NG Processors - Sweet	Rotors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.
		Set valve positions to run compressor at optimum efficiency and reduce bypass (process suction pressure valve, bypass valve, backpressure control valve)
		Volume pocket adjustments - manual or automatic to match inlet gas stream
		Set cylinder clearance to a minimum to optimize compressor efficiency
		Inlet and Interstage cooling
NG Processors-Sour	Drivers	Improved performance monitoring, optimization and servicing practices
	Rotors	Inlet and Interstage cooling
Light and Medium Oil	Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners
	Drivers	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing
		Oilfield Pumping - Perform routine testing and correction of abnormalities
		Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing
		Oilfield Pumping - Perform routine testing and correction of abnormalities
	Rotors	Annual air leak detection and repair program
Conventional Heavy Oil	Heating	Oil treater temperature control to avoid over heating and over treating

Sub-Sector	Enduse	Measure
Bitumen	System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance
		Power factor > 95%
		Up-to-date DCS or PLC controls to optimize equipment run times and rates
	Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners
		Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers
		Line heater operating practices (seasonal)
		Boiler blowdown optimisation
		Oil treater temperature control to avoid over heating and over treating

5.4 Sector And Sub-Sector Energy Efficiency Technical Potential And GHG Emission Reduction

If all the technically feasible best practices are implemented then total UOG energy use is estimated to increase by 195 PJ from 2007 to 2030, compared to an increase of 374 PJ in the Reference Case. The estimated energy use in 2030 is 16% less compared to the energy use in the Reference Case as illustrated in Figure 30, and summarized by sub-sector, fuel type and end use in Figure 31 to Figure 33. Note that this potential does not take into account the improvements that could be realized by more aggressive process-based design optimization and use of cutting edge technologies which were not considered as part of this project (as noted in Section 5.1.1. the UOG sector is not generally receptive to these technologies) and does not include the savings potential from incineration (which was not directly modeled as explained in Section 4.1.1).

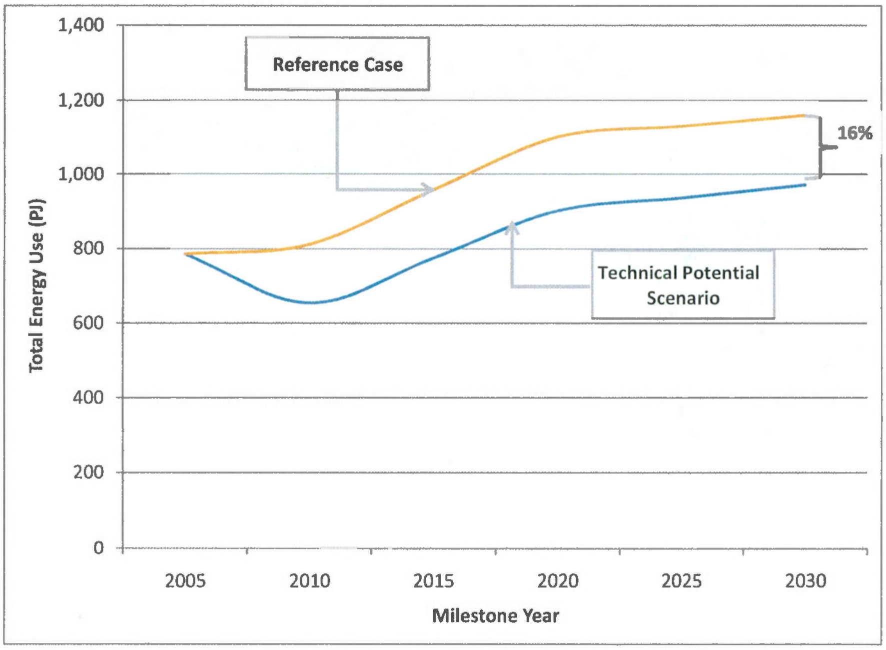
Additional energy savings can be achieved in the sour gas subsector by the implementation of best practices for incinerators. Determining optimum incinerator operating conditions and running incinerators at these conditions will reduce incinerator temperature and oxygen levels to optimum levels and could save on average 5% of the energy consumption by the incinerator. This measure does not have associated capital costs, and can be implemented as part of the facility maintenance schedule. The associated energy savings for the subsector amount to 8 PJ in the first milestone year.

An alternative solution for the reduction in energy use in incinerators is their replacement with high efficiency incinerators which typically consume 5% less energy. This amounts to about 8 PJ savings in the first milestone year assuming all existing incinerators will be replaced. However, the associated capital costs with this option have to be considered.

An alternative solution for the reduction in energy use in incinerators, dehydrator regenerators and flares is their complete replacement with high efficiency incinerators which can consume up to 80% less energy. With 5000 glycol dehydrators and 10,800 flares in Alberta the opportuniry is sizeable (estimated at up to 128 PJ of technical potential). Current case studies on high efficiency incinerator usage as replacement for dehydrators and flares show a payback of 4 to 6 months based on fuel savings plus potential additional revenues from carbon credits. However, the associated capital costs with this option would have to be considered on a case-by-case basis.

As discussed in Section 4.1.2, natural gas and fuel gas account for 92% of the total projected energy use in 2030. In the Technical Potential scenario these two fuels account for the largest energy savings by 2030. Natural gas is estimated to save 96 PJ in 2030 compared to the Reference Case scenario, which is 53% of the total 2030 industry savings. The significant savings potential estimated for the process heating end use are the main reasons for the large natural gas savings potential. The system end use, which includes measures that apply to the total plant, is estimated to contribute close to 12% of all the Technical Potential savings by 2030.

Figure 30: Reference Case And Technical Potential Scenario Energy Use For Total UOG.



Based on the modelling methodology described in Section 5.1.3, an initial drop in the energy consumption is observed between the base year and the first milestone year. As the energy consumption grows according to the forecast, the savings become an increasingly smaller fraction of the total energy consumed and the curve will pick up an upward trend.

Figure 31: Reference Case And Technical Potential Scenario Energy Use By Energy Source (PJ).

	Base Year Energy Use	2030 Reference Case Energy Use	2030 Technical Potential Energy Use	2030 Technical Potential Savings	
Energy Source	PJ	PJ	PJ	PJ	%
Natural Gas	308	623	528	95	15%
Electricity	62	98	90	8	8%
Fuel Gas	417	439	356	83	19%
Total	786	1160	973	186	16%

Per sub-sector the potential energy savings in 2030 range between 14% and 38% compared to Reference Case energy use. The Bitumen sub-sector accounts for the largest absolute amount energy savings at 83 PJ. The Conventional Heavy Oil sub-sector shows the largest percentage Technical Potential savings at 37%. The three oil sub-sectors have the potential to save the largest portion, i.e. 63%, of the total estimated Technical Potential savings.

Figure 32: 2030 Technical Potential Scenario Energy Savings By End Use (PJ).

End Use	2030 Technical Potential Savings	Savings as Percentage of Total
	PJ	%
System	23	12%
Heating	140	75%
Cooling	0	0.1%
Drivers	10	5.3%
Rotors	8	4.1%
Total	181	100%

Per sub-sector the potential energy savings in 2030 range between 10% and 37% compared to Reference Case energy use. The Bitumen sub-sector accounts for the largest absolute amount energy savings at 83 PJ compared to its own Reference Case energy use in 2030. The Conventional Heavy Oil sub-sector shows the largest percentage Technical Potential savings at 37% compared to its own Reference Case energy use in 2030. Together, the three oil sub-sectors have the potential to save the largest proportion, i.e. 63%, of the total estimated Technical Potential savings.

Figure 33: Reference Case And Technical Potential Scenario Energy Use By Sub-Sector (PJ).

	Base Year Energy Use	2030 Reference Case Energy Use	2030 Technical Potential Energy Use	2030 Technical Potential Savings	
Sub-sector	PJ	PJ	PJ	PJ	%
NG Producers	221	181	139	42	23%
NG Producers - Sweet	40	28	20	8	28%
NG Processors - Sour	228	162	138	23	14%
Light & Med Oil	84	169	145	23	14%
Conventional Heavy Oil	16	17	11	7	38%
Bitumen	198	603	519	84	14%
Total	786	1,160	973	186	16%

This section describes the development and results of the technical energy savings potential. The development of the technical energy savings potential includes the identification of energy efficiency and conservation best practices, and the market penetration rates of the best practices. This section discusses the technical best practices and the market penetration of the best practices in the Base Year.

6.0 Economic Potential for Energy Efficiency

6.1 Methodology

To determine the economic feasibility of the technical best practices the Total Resources Cost (TRC) test is used. The TRC calculates the net present value (NPV) of energy savings that result from an investment in an efficiency measure. The TRC for an individual TBP is equal to its full or incremental capital cost (according to whether it is a retrofit or a replacement measure, respectively) plus any change (positive or negative) in the combined annual energy and equipment operating and maintenance costs. This calculation includes, among others, the following inputs: the avoided natural gas, fuel gas and electricity costs, the life of the technology and the selected discount rate. The TRC formula and input parameters are presented in Appendix A. The TRC assessment of each measure is based on an average representative size of the end use or "Baseline Technology". 'Baseline technology' refers to the main equipment that a measure applies to, for example a boiler is the baseline technology for a boiler economizer. The sizes of the baseline technologies are provided in Appendix F.

Best practices or measures with a positive TRC value are considered to be economically feasible from a societal point of view and are included in the Economic Potential scenarios. A measure with a negative TRC value is not economically attractive (from a societal point of view) and is therefore not included in subsequent stages of the analysis. The technical best practices are applied at either natural stock turnover rates for replacement technologies, or at the first milestone years for immediate application of retrofit technologies.

Section 5 presents the market penetration rates of the best practices in 2005 – the Base Year. The difference between the full technically feasible implementation of the best practices in industry and the Base Year market penetration rates provide the Economic Potential scenario market penetration rates.

6.2 ECONOMIC SCREENING OF BEST PRACTICE OPPORTUNITIES

A summary of the TRC results is provided in Figure 34, using the Natural Gas Processors (Sour) sub sector as an example. The parameters used in the TRC test are presented in Appendix A1. The TRC results for all of the sub-sectors are provided in Appendix A2-A7. The full avoided costs of the fuels are included in the TRC calculation, i.e., both generation and transmission costs for electricity are considered. In other words, the TRC test not only looks at onsite energy cost to the facility in question, but also the cost (or the avoided cost due to reduced energy use) to society for installing and maintaining energy infrastructure (such as the electricity grid).

Figure 34: TRC Of Best Practices (Example Using Natural Gas Producers Sub-Sector)

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$445,483	Pass	0.0
System	Power factor > 95%	$218,489	Pass	0.0
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	$1,605,504	Pass	3.7
Heating	Improved design practices and conversion from natural draft to forced air systems.	$276,276	Pass	-4.5*
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	$165,681	Pass	0.8
Heating	Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	$61,291	Pass	5.3
Heating	Boiler blowdown optimisation	$41,018	Pass	5.7
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$95,624	Fail	14.3
Heating	Annual steam trap surveys and repair	$25,303	Pass	4.8

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Cooling	Use sub-cooler to increase percent liquid entering chiller	$21,254	Pass	27.2
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	$154,541	Pass	2.6
Cooling	Optimized automated condenser control	$228,136	Pass	0.8
Engines/ Gas turbines	Improvement of engine operation	$6,263,655	Pass	0.4
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$549,346	Pass	7.7
Air Compressors	Annual air leak detection and repair program	$7,037	Pass	1.0
Air Compressors	Intake air temperature reduction	$3,860	Pass	1.6
Pumps	Pump selection in lead/lag or primary/secondary	$76,753	Pass	0.1
Pumps	Sulphur Recovery - Optimize SRU performance	-$72,577	Fail	58.1
Fans/Blowers	Two speed motors or variable speed drives	$65,706	Pass	0.9
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$14,845	Pass	1.7
Fans/Blowers	Sulphur Recovery - Optimize SRU performance	-$48,099	Fail	18.0
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	$412,481	Pass	0.3
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	$427,908	Pass	0.1
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$602,133	Pass	-95.4*

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	$286,909	Pass	0.1
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	$119,294	Pass	0.7
Gas Compressors	Acid Gas Injection - Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.	$14,270	Pass	0.3

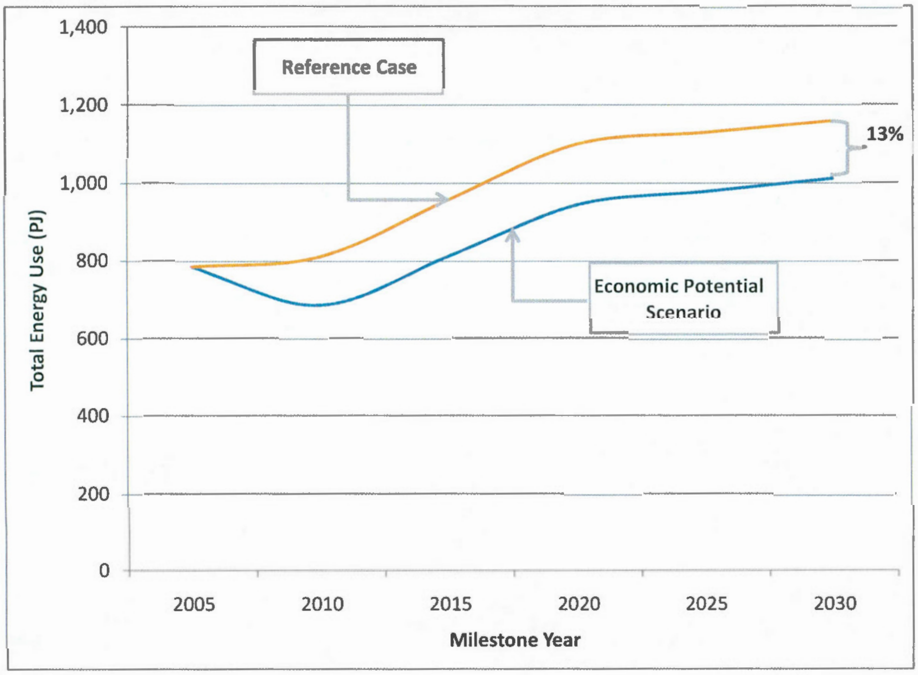
* A negative payback indicates that the cost of the replacement measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

6.3 Sector And Sub-Sector Energy Efficiency Economic Potential And GHG Emission Reduction

If all the economically feasible best practices are implemented then total UOG sector energy use is estimated to increase by 233 PJ from 2005 to 2030, compared to an increase of 374 PJ in the Reference Case. The estimated energy use in 2030 is 13% less compared to the energy use in the Reference Case. The estimated energy use and savings by subsector is illustrated in Figure 35 and summarized by sub-sector, fuel type and end use in Figure 36, Figure 37and Figure 38.

The energy savings based on the Economic Potential scenario follow a trend similar to the savings associated with the Technical Potential scenario, showing an initial drop in the energy consumption between the base year and the first milestone year. As the energy consumption grows according to the forecast, the savings become an increasingly smaller fraction of the total energy consumed and the curve will pick up an upward trend.

Figure 35: Reference Case And Economic Potential Scenario Energy Use For The UOG Sector



Per sub-sector the potential energy savings in 2030 range between 10% and 39% compared to Reference Case energy use. The observations for the Economic Potential scenario are very similar to the Technical Potential Scenario:

- The Bitumen sub-sector accounts for the largest absolute amount energy savings at 59 PJ compared to its own Reference Case energy use in 2030.
- The Conventional Heavy Oil sub-sector shows the largest percentage Economic Potential savings at 39% compared to its own Reference Case energy use in 2030.
- Together, the three oil sub-sectors have the potential to save the largest portion, i.e. 60%, of the total estimated Economic Potential savings.
- The largest GHG savings are associated with Bitumen subsector, as illustrated in Figure 39. As the energy saving measures are implemented according to the methodology described in Section 5.1.3, an increase in GHG reduction potential is observed. However, based on the forecast for the Bitumen subsector, the total energy consumption will increase more than 200% by 2030, and the energy and GHG savings will reach their effectiveness limit by 2020. By this point, growth in emissions due to increased production will negate any further savings from best practices implementation.

Figure 36: Reference Case And Economic Potential Scenario Energy Use By Sub-Sector (PJ).

	Base Year Energy Use	2030 Reference Case Energy Use	2030 Economic Potential Energy Use	2030 Economic Potential Energy Savings	
Sub-sector	PJ	PJ	PJ	PJ	%
NG Producers	221	181	144	37	20%
NG Processors - Sweet	40	28	21	7	25%
NG Processors - Sour	228	162	144	18	11%
Light & Med Oil	84	169	149	19	11%
Conventional Heavy Oil	16	17	11	7	39%
Bitumen	198	603	544	59	10%
Total	786	1,160	1,012	147	13%

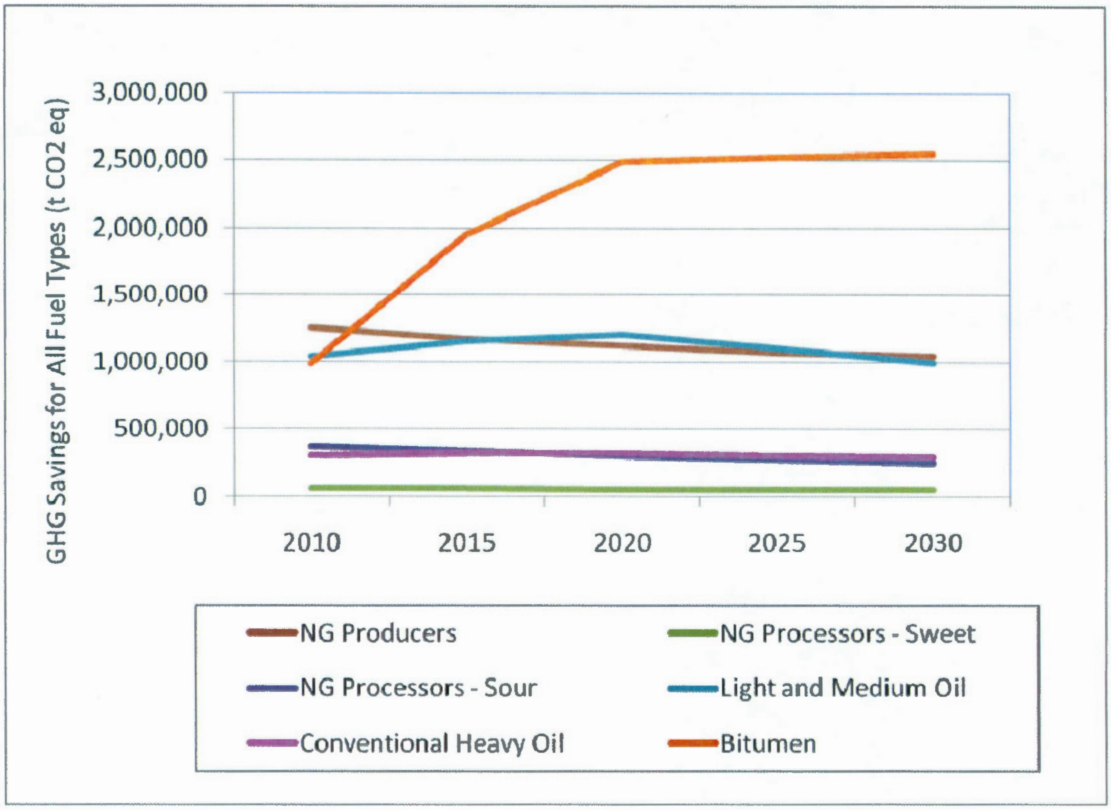
Figure 37: Reference Case And Economic Potential Scenario Energy Use By Fuel Type (PJ).

	Base Year Energy Use	2030 Reference Case Energy Use	2030 Economic Potential Energy Use	2030 Economic Potential Energy Savings	
Energy Source	PJ	PJ	PJ	PJ	%
Natural Gas	308	623	551	72	12%
Electricity	62	98	92	6	6%
Fuel Gas	417	439	369	69	16%
Totals	786	1160	1012	147	13%

Figure 38: Reference Case And Economic Potential Scenario Energy Use By End Use (PJ).

End Use	2030 Economic Potential Savings	Savings as Percentage of Total
	PJ	%
System	21	15%
Direct Fired Heaters/Steam Boilers	104	74%
Refrigeration Compressors	0	0%
Engines/ Gas Turbines	10	7.2%
Motors	0	0%
Air Compressors	0	0%
Pumps	1.7	1%
Fans/Blowers	1	1%
Gas Compressors	3.1	2.2%
Total	142	100%

Figure 39: GHG Saving Associated with the Economic Potential Scenario by Sub-sector



6.4 Economic Potential Cost Curves

6.4.1 Methodology

Cost curves are used to provide a graphical representation of the aggregate potential of a wide array of energy efficiency opportunities. A cost curve (or supply curve) typically consists of two axes: one that captures the cost per unit of energy savings or mitigating an impact (e.g., $/GJ saved or $/tonne of carbon avoided) and the other that shows the amount of savings (GJ) or mitigation (tonne of carbon) that could be achieved at each level of cost. In this study, cost curves in terms of costs per unit of energy savings are provided.

The cost curves are typically built up across individual measures that are applied to specific practices by sub-sector. Savings are sorted on a least-cost basis and total savings or impacts mitigated are calculated incrementally with respect to measures that precede them (in this way, the most cost-effective TBPs are applied first). The energy savings of the second and subsequent measures are represented only by the "additional" energy savings given the implementation of the first measure. It is therefore normal for cost curves to reflect diminishing returns, i.e., as the cheapest measures are applied first, the energy savings potential is greatest. As costs increase for further measures, the incremental energy savings that are possible rapidly become smaller, and so the effectiveness of each subsequent measure is reduced significantly at the end of the curve.

A typical energy efficiency measure requires capital, installation and operation and maintenance costs. These costs do not occur at the same time. Capital and installation costs occur at the beginning of the project (often assumed as a lump-sum). Operation and maintenance are usually annual costs that occur over the lifetime of the measure. Therefore, the stream of costs needs to be "aggregated" at a single point in time (by means of discounting) and the total (discounted) costs must then be annualized. A real discount rate of 8% is used following Treasury Board's Guidelines for Economic Analysis (Treasury Board of Canada Secretariat, 2007). The present value of the costs of the energy efficiency measure (PVC) using the Equation 1:

Equation 1: Present Value Costs

$$PV_C = \sum_{t=0}^{T} \frac{C_t}{(1+i)^t}$$

Where:

- T is the lifetime of the installed equipment (years)
- Ct are the costs at year t;
- i is the discount rate.

The annualized costs (A) is determined using Equation 2:

Equation 2: Annualized Costs

$$A = PV_C \frac{i}{1-(1+i)^{-T}}$$

By dividing the annualized costs by the average energy savings, the unit cost of energy efficiency ($/GJ) is determined. These values are used in the vertical axis of the energy efficiency cost curves.

The Economic Potential cost curves follow the same conditions as the rest of the scenario analysis: that is, they represent the economic potential of energy savings opportunities if all the technically feasible measures, which are considered to be economically feasible from a societal point of view, are implemented. Additionally, in producing these cost curves, we assume that retrofits and replacements can be done all at once; without needing to wait for existing equipment to fully depreciate.

The cost curves for the six sub-sectors are provided in Figure 40 to Figure 45. The associated order by which the measures are implemented to derive the cost curves is summarized in Appendix G. The figures present some examples of measures with the highest potential energy savings. The costs curves shown below can help facility owners to identify which energy efficiency measures to undertake (and which ones to undertake first). Clearly, the implementation of energy efficiency measures that lay at the left side of the curve would represent higher economic benefits. Furthermore, as the curves show that most of the recommended measures can be undertaken at a cost below $1/GJ, the benefits of energy/fuel savings can significantly outweigh the costs of implementing the measures.

Figure 46 shows the aggregate potential for energy efficiency of the entire Upstream Oil and Gas sector. This curve is derived based on the economic potential scenario for 2030 and the sector-specific cost curves.

6.4.2 Cost Curves

The cost curves for the six sub-sectors are provided in Figure 40 to Figure 45. The associated order by which the measures are implemented to derive the cost curves is summarized in Appendix G. The figures present some examples of measures with their corresponding potential energy savings. The cost curves shown below can help facility owners to identify which energy efficiency measures to undertake (and which ones to undertake first). Clearly, the implementation of energy efficiency measures that lay at the left side of the curve would represent higher economic benefits. Furthermore, as the curves show that most of the recommended measures can be undertaken at a cost below $1/GJ, the benefits of energy/fuel savings can significantly outweigh the costs of implementing the measures.

Figure 40: Cost Curve for Natural Gas Producers

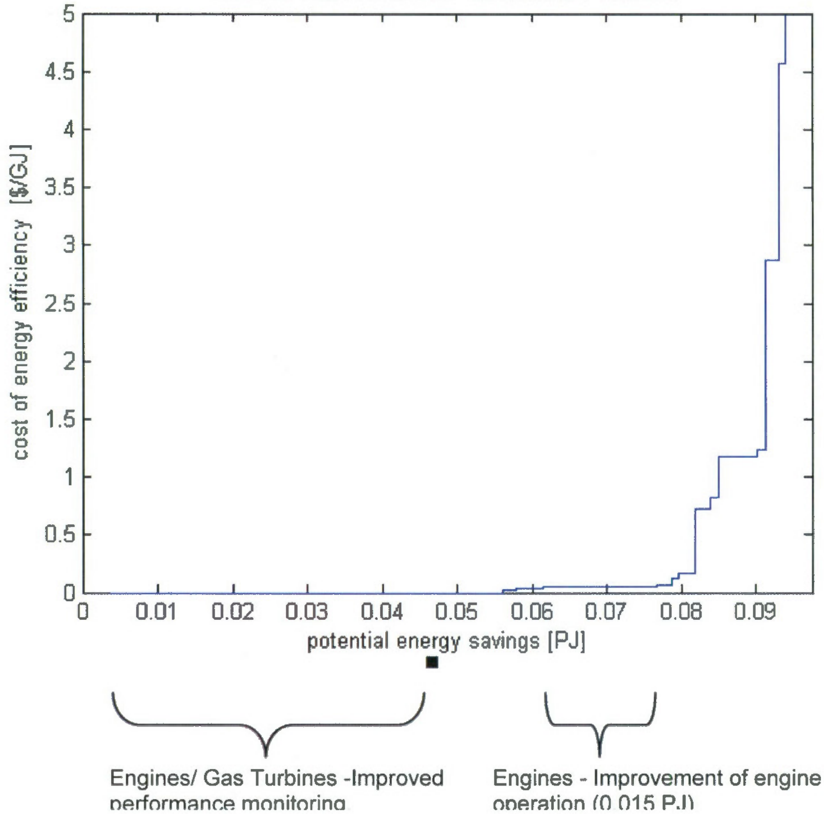


Figure 41: Cost Curve for Natural Gas Processors (Sweet)

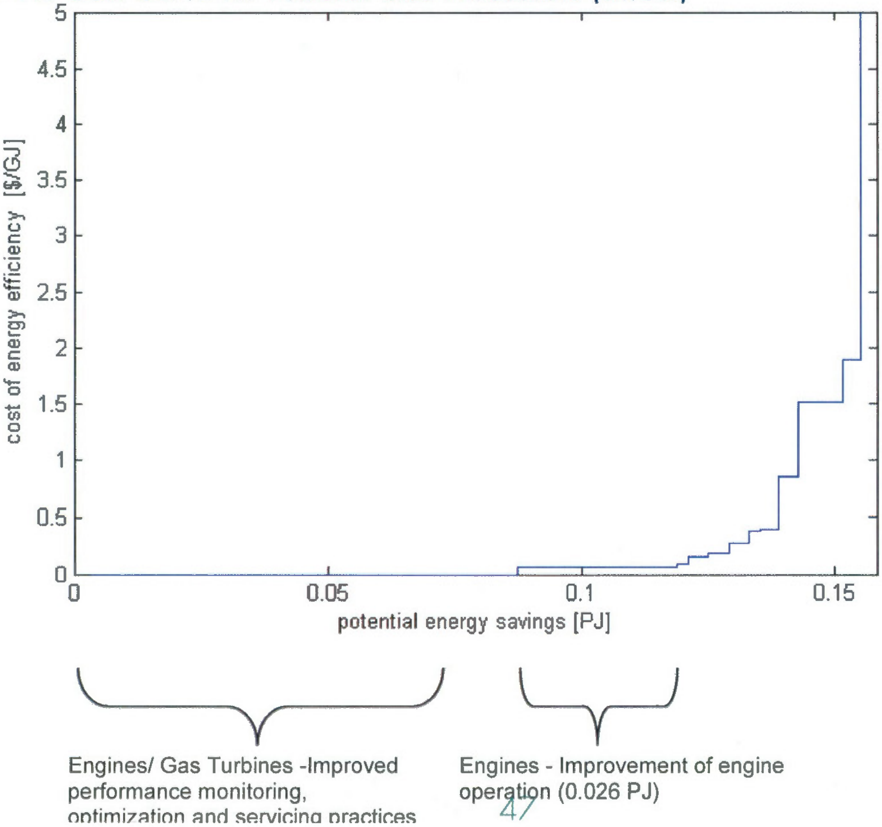
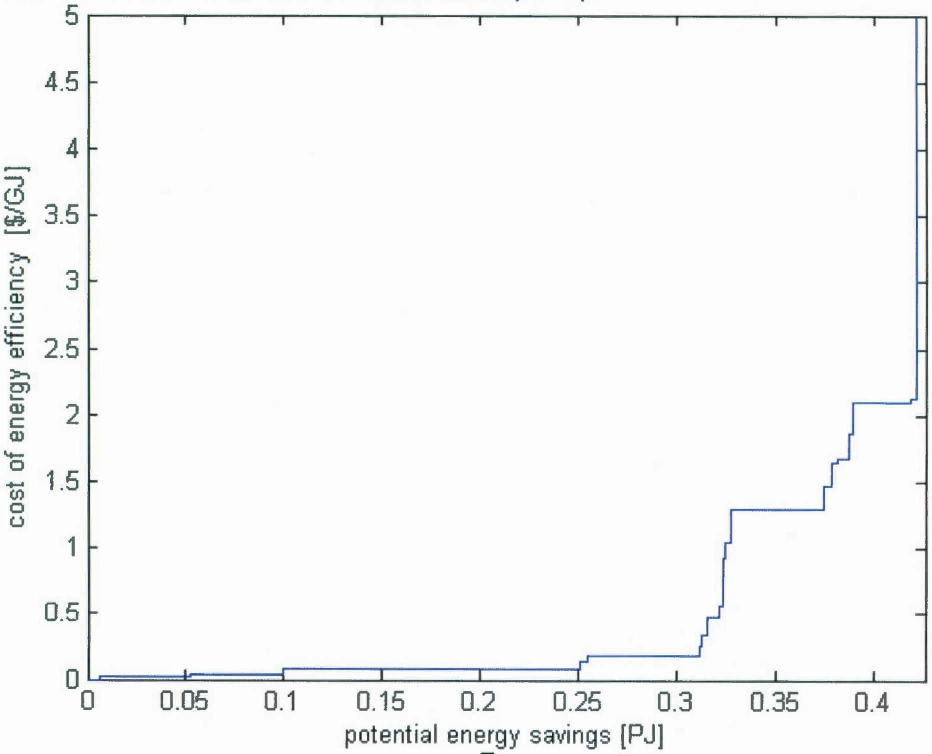


Figure 42: Cost Curve for Natural Gas Processors (Sour)

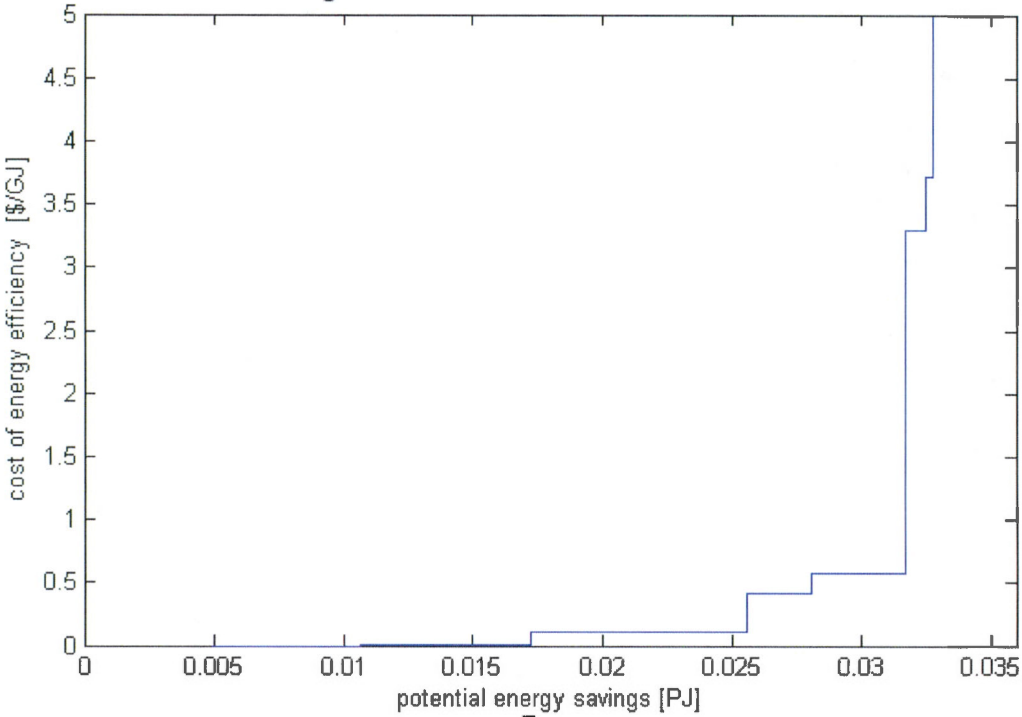


System - Check power quality - level and type of harmonics, entrance voltage

Engines - Improvement of engine operation

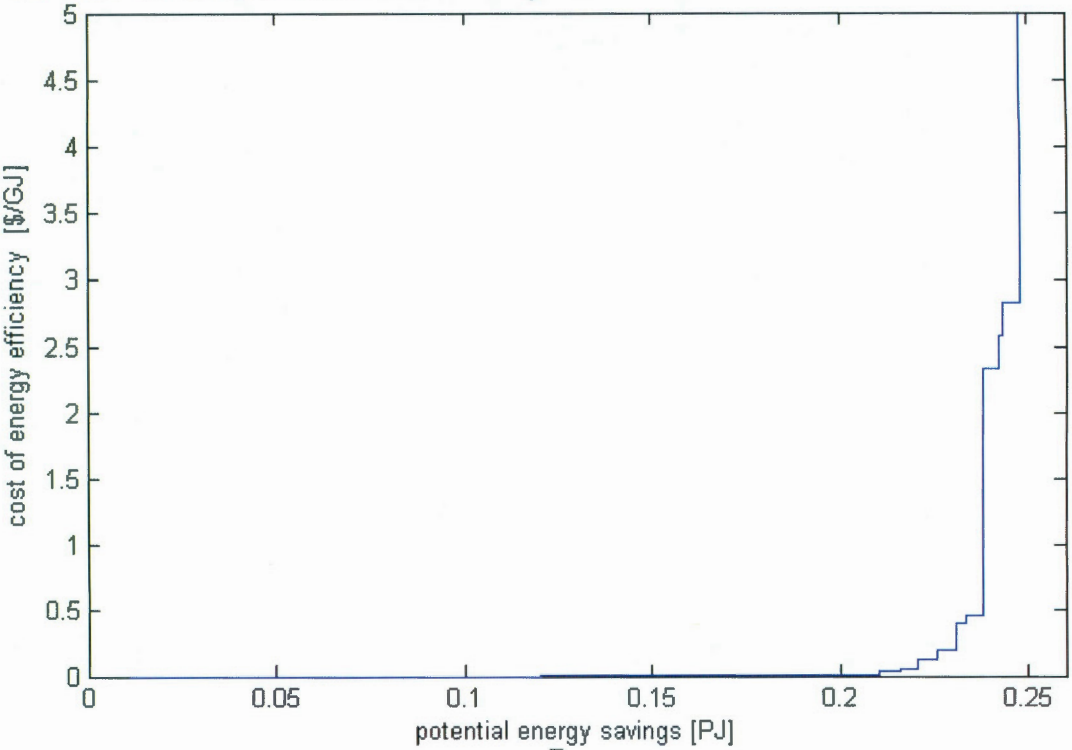
Engines/ Gas Turbines - Improved performance monitoring, optimization

Figure 43: Cost Curve for Light and Medium Oil



Gas Compressors - Gathering Gas Compressors - Set Gas Turbines - Utilization of

Figure 44: Cost Curve for Conventional Heavy Oil



- Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices (0.069 PJ)

  Engines - Oilfield Pumping - Perform routine testing and correction of abnormalities (0.010 PJ)

- Engines - Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing (0.043 PJ)

  Engines - Improvement of engine operation (0.026)

Figure 45: Cost Curve for Bitumen

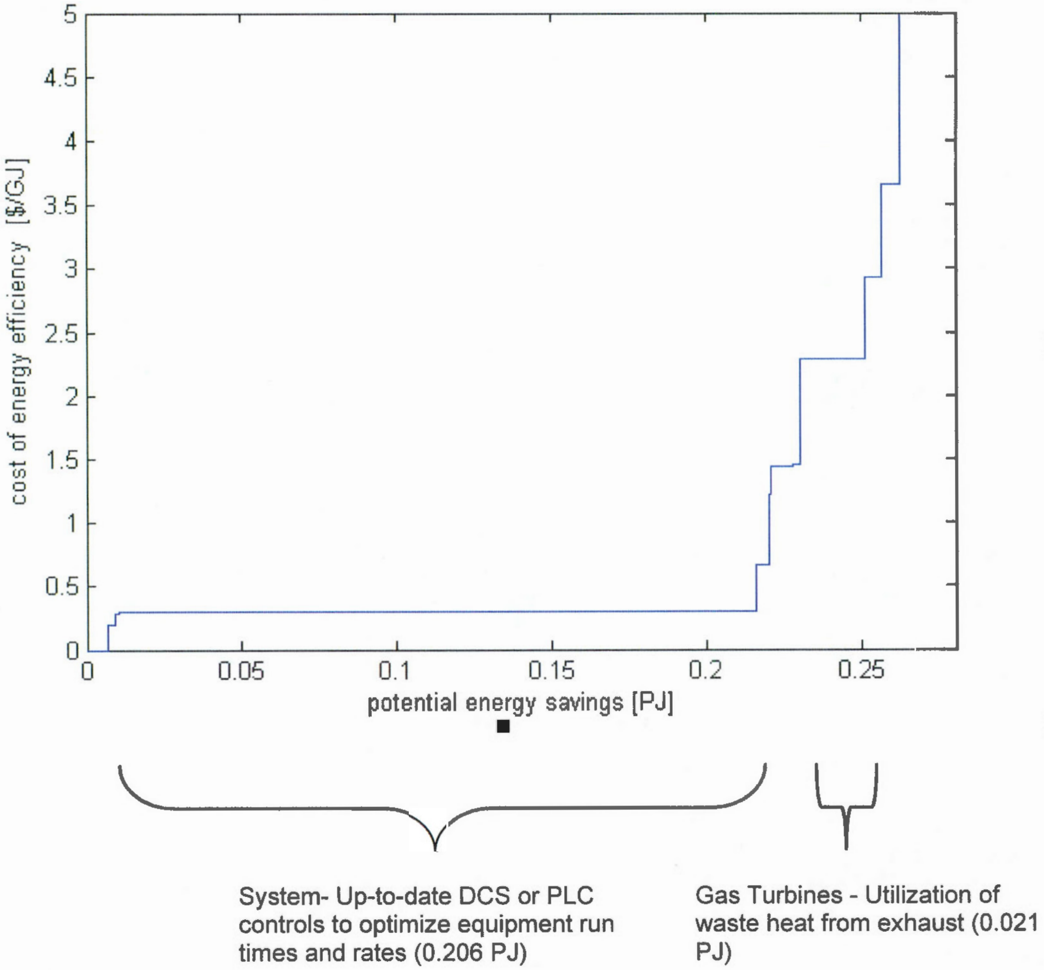
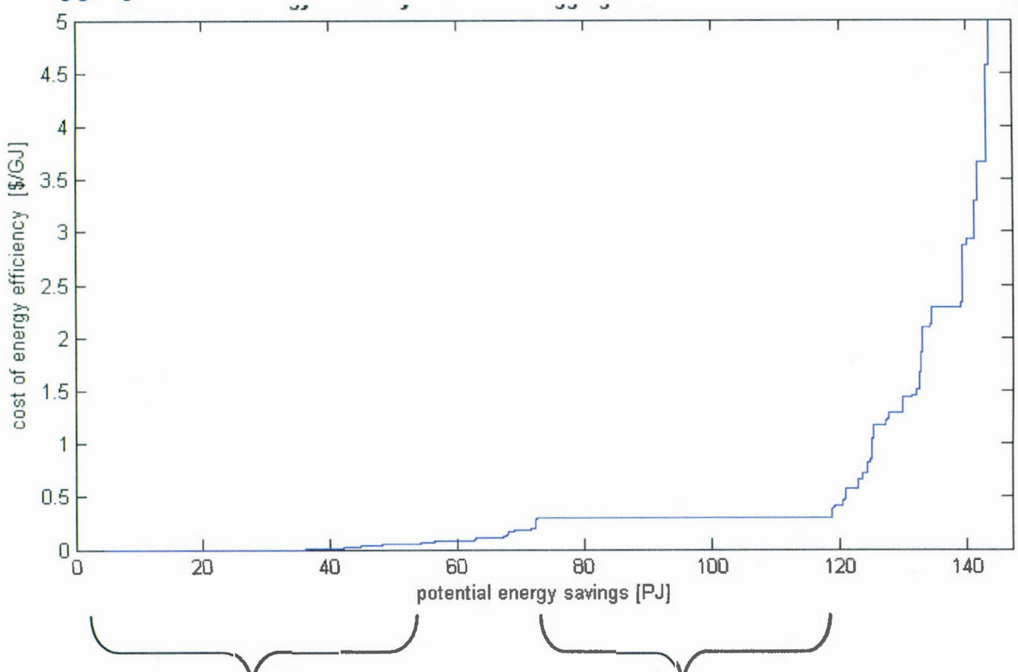


Figure 46: Aggregate Cost Curve for the UOG sector



Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume -Light and Medium Oil (1.75 PJ)

Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices -NG Producers (15.35 PJ)

Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices -NG Processes Sweet (3.07 PJ)

Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices - Heavy Oil (1.95 PJ)

Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency -Light and Medium Oil (2.20 PJ)

System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance –NG Processes Sour (1.99 PJ)

System - Power factor > 95% -NG Processes Sour (1.99 PJ)

Engines - Improvement of engine operation -NG Producers (5.76 PJ)

System - Up-to-date DCS or PLC controls to optimize equipment run times and rates -Bitumen (46.11 PJ)

7.0 Implementation and Management Best Practices

7.1 Methodology

Similar to the assessment of the TBP, a scoring system was used to convert the information submitted by the plants and the corporation on the MBP survey into implementation rates. The response to each MBP was given a score, using the following system when the best practice is either present or not:

Management best practice fully implemented in facility/corporation (yes): score = 2
Management best practice partially implemented in facility/corporation (partially): score = 1
Management best practice not employed (no): score = 0

The MBPs scores are determined at the category level and at the sub-sector level. Twenty-nine plants participated in the energy performance benchmarking assessments.

7.2 Management Best Practice Results

The implementation of the MBP is given in Figure 46 and Figure 47. Due to insufficient participation rate and confidentiality, the results for the Conventional Heavy Oil and Bitumen sectors are aggregated.

Figure 47 - Implementation of MBP by Sub-sector (%)

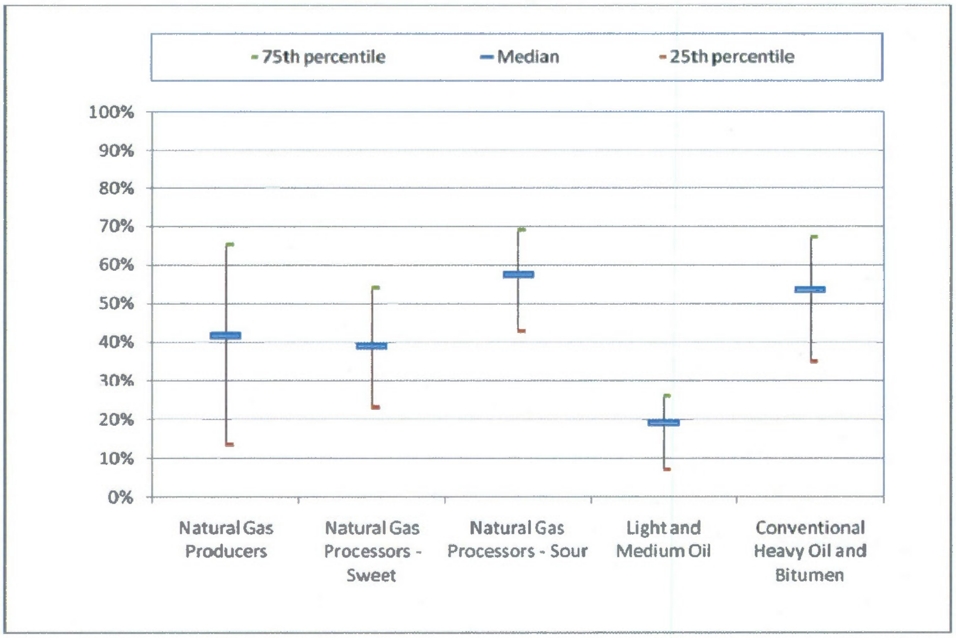
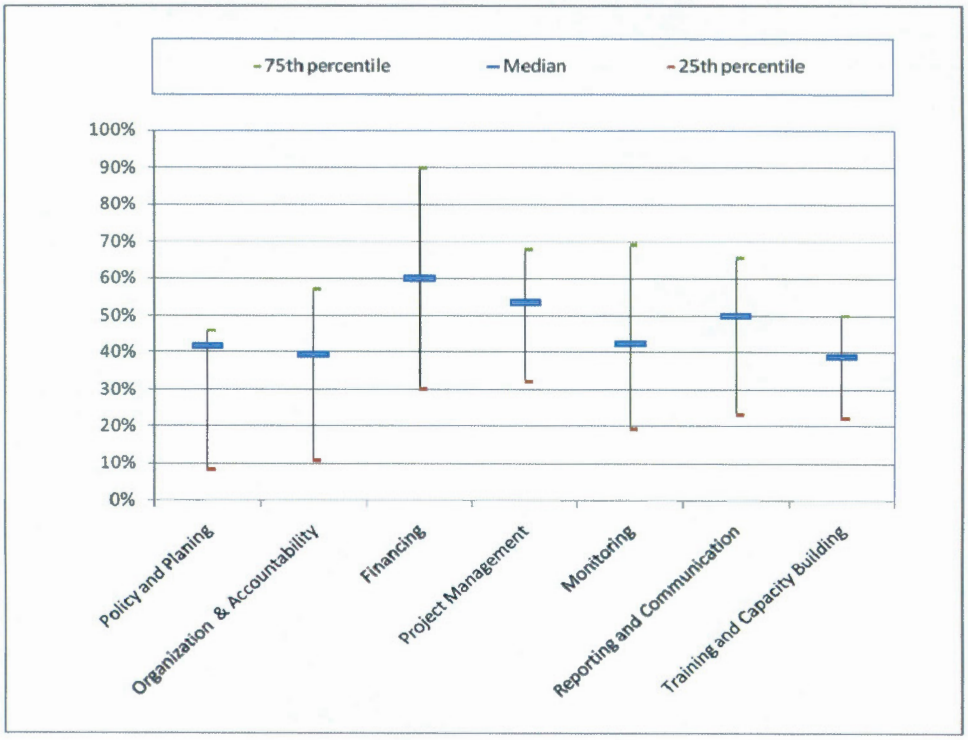


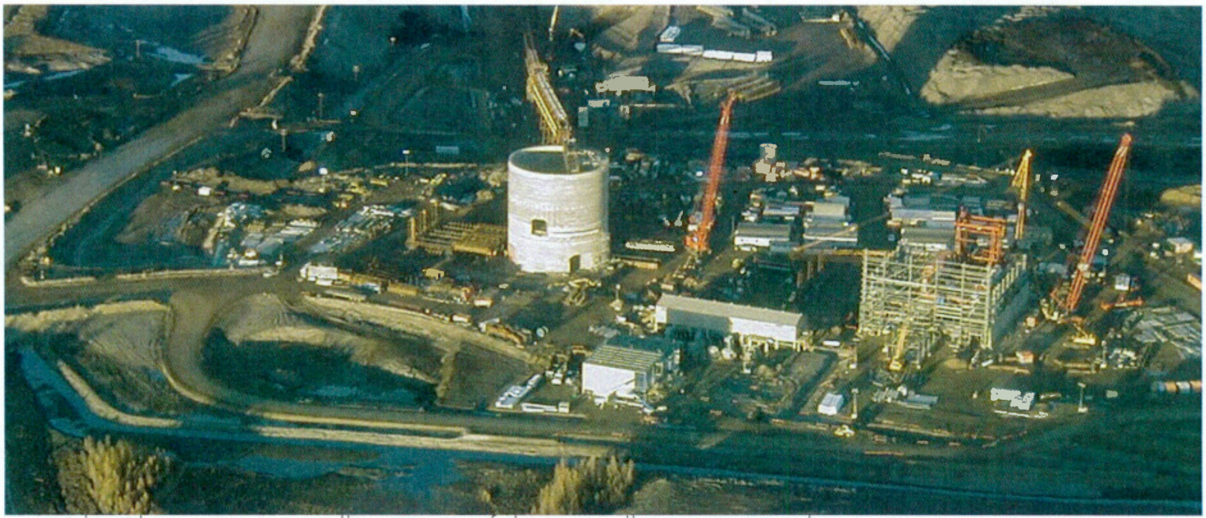
Figure 48 - Implementation of MBP by Best Practices Category (%)



7.3 Trends And Correlations

The sample size and the types of the facilities selected for the survey of the UOG sector provided a representative mix of facility size and types of operation. A total of 29 best energy management surveys were received and analyzed. Some of the trends that can be concluded with a good level of confidence are listed below:

- A large variation in MBP scores among the facilities within each subsector is observed. The extent of variation of the average scores between subsectors is lower but still significant. The Natural Gas Processors – Sour and Light and Medium Oil with averages scores of 54% and 20% scored the highest and lowest respectively.
- The implementation rate of MBPs roughly correlates with the energy consumption of the sub-sectors; that is, the sub-sectors with the highest absolute energy consumption (Natural Gas Producers, Natural Gas Processing (Sour) and Bitumen, as shown in Figure 14) also have the highest rates of MBP implementation.
- In terms of MBP implementation by category, financing of energy management projects has the highest score. Policy and planning, organization and accountability, and training and capacity building have low levels of best practices implementation. This result is consistent with previous projects carried out by the project team in other industrial sectors, and is typical of cultures that address energy efficiency through one-off, ad-hoc projects



rather than systematically as part of the overall corporate culture.

- Only about 6% of the facilities have adopted some or all aspects of the ANSI: MSE 2005 energy management system, suggesting that energy is rarely addressed within a formalized setting.
- In general, no strong correlation was found between the size of the facility and the implementation of energy monitoring systems. However, as shown in Figure 49, the largest facilities usually had the highest monitoring score; this is unsurprising given the cost of monitoring infrastructure and the need for many larger facilities to monitor closely all their operational parameters for compliance reporting under local environmental licensing etc. However, the opposite could not be confirmed, i.e. there were a number of large, medium and small facilities with low monitoring scores.
- The above trend can be generalized to all of the MBPs. In other words, as shown in Figure 50, the largest facilities usually had the high MBP scores, but the opposite was not found to be true.
- The highest scoring facility among the UOG facilities obtained a MBP score of 81%. This indicates that there are "leaders" of energy management in the UOG sector, who understand the importance of managing energy and are actively doing something about it. Such "leading lights" could provide the inspiration for their peers by proving that energy can and should be managed.
- Previous project experience suggests that there is normally a relationship between high implementation of MBPs and TBPs. Within this study, however, there was insufficient data to properly correlate the two implementation rates.

Figure 49 - Relationship Between Facility Number of Employees and Implementation of Energy Monitoring Systems

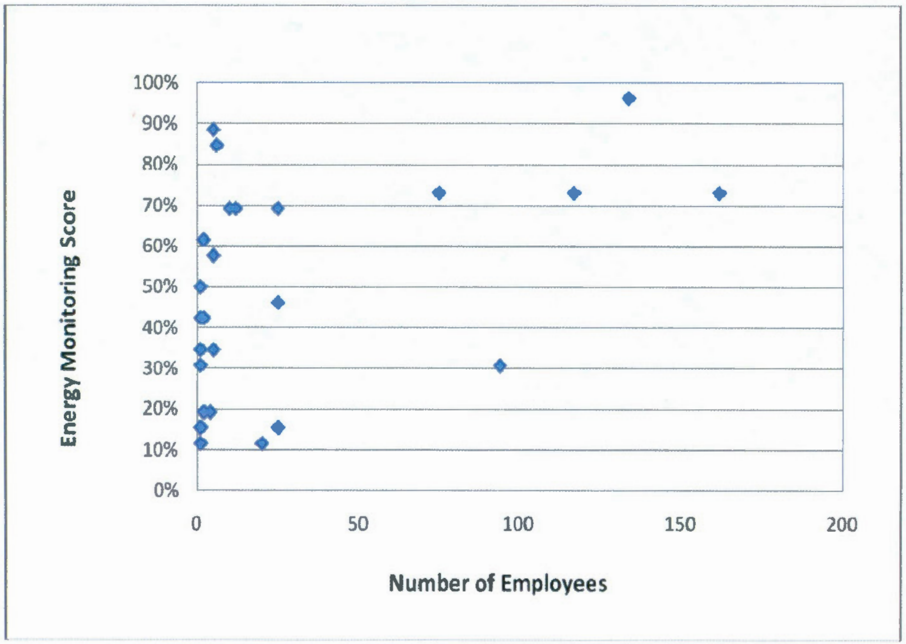
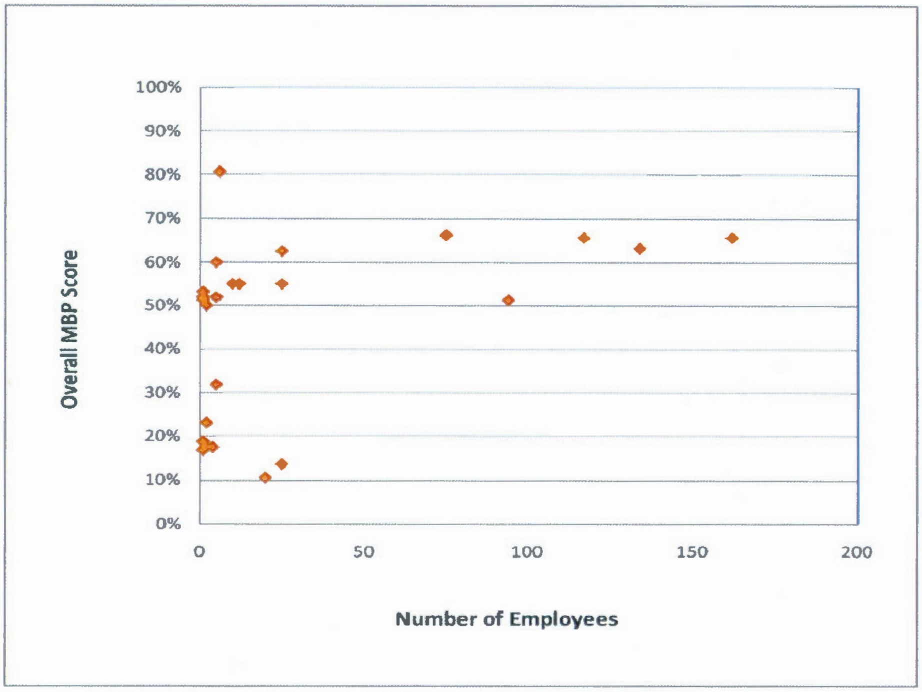


Figure 50 - Relationship between facility number of employees and MBP score



8.0 Waste Reduction

8.1 Methodology

As with TBPs, only WRBPs that were technically feasible and commercially available were included in the analysis. A total of 20 WRBPs were selected from the literature review and presented to the Steering Committee. It should be noted that the analysis of the WRBPs is performed qualitatively and included the calculation of market penetration of WRBPs from the analysis of the survey data.

8.2 Waste Reduction Opportunities

Waste reduction opportunities are listed in Figure 51. The 20 WRBPs applicable to the UOG sector are divided to the following categories:

- Flaring
- Pipelines
- Tanks
- Valves
- Compression (methane savings)
- Natural gas dehydrators (methane savings)
- Chemical injection pumps
- LDAR program

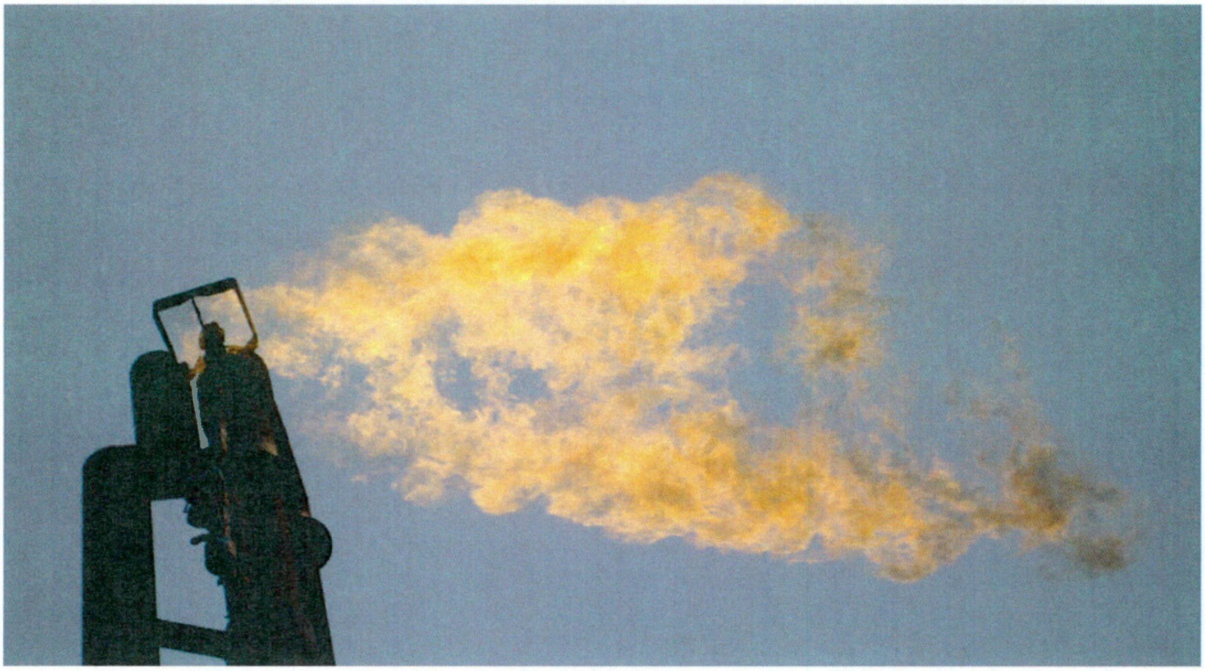


Figure 51: List Of Waste Reduction Best Practices

Equipment or Process	Measure
Flaring	Flaring reduction/optimization techniques: document and report gas going to flare, correct or replace underperforming flaring equipment, extinguish pseudo-dormant flares, reduce pilot gas consumption, reduce purge gas consumption, reduce make-up gas consumption
Pipelines	Pipeline pump-down techniques are used to lower gas line pressure before maintenance; inert gases and pigs are used to perform pipeline purges
	Pipe flow analysis is performed to reduce bottleneck and turbulent flow and corrosion
	Perform pigging to remove wax build up from the pipe walls in oil gathering systems
	Hydrate formation mitigation is evaluated based on cost and emissions - e.g. Methanol can de injected into pipelines as an alternative to using line heaters to inhibit hydrate formation.
	Recover Gas from Pipeline Pigging Operations
	Close all thief hatches and man hole covers
Tanks	Install Vapor Recovery Units on Crude Oil Storage Tanks
	Close all thief hatches and man hole covers
	Maintain seals on thief hatches and man hole covers

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Equipment or Process	Measure
Valves	Inspect and Repair Compressor Station Blowdown Valves
	Reduce gathering system gas pressure build up due to plant shutdowns through depressuring and recirculating gas back to inlet and shutting in field supply and compression
	Test and Repair Pressure Safety Valves Annually
Compression-methane savings	Engine ignition system is upgraded to reduce restarts, improve air-fuel mix and reduce associated air emissions
	Reducing Methane Emissions from Compressor Rod Packing Systems
	Reducing Emissions When Taking Compressors Off-Line/ Adjust blowdown and ESD practices
Natural Gas Dehydrators - Methane savings	Optimize glycol circulation rates
Chemical Injection Pumps	Replace pneumatic pumps with electric pumps
LDAR program	Leak detection and repair

8.3 Waste Reduction Potential

According to NRCan/NEB forecasts (NRCan, 2006; NEB, 2009) shown in Figure 52, natural gas flaring is responsible for wasting 57 PJ energy in the Base Year, and this is expected to increase to 76 PJ by 2030.

Figure 52: Reference Case for Natural Gas Wasted by Flaring in Canada's Uog Sector (GJ)

Waste	2005	2010	2015	2020	2025	2030
Total Natural Gas Flaring	57,069,204	63,065,071	68,666,234	74,288,287	75,323,414	76,358,540

Figure 53 - Implementation of Waste Reduction Best Practices

	Natural Gas Producers	Natural Gas Processors - Sweet	Natural Gas Processors - Sour	Light and Medium Oil	Conventional Heavy Oil and Bitumen
Flaring	75%	60%	81%	Insufficient data	Insufficient data
Pipelines	80%	81%	87%	79%	Insufficient data
Tanks	-	-	-	80%	Insufficient data
Valves	69%	73%	71%	71%	56%
Compression-Methane Savings	71%	60%	79%	-	-
Natural Gas Dehydration - Methane Savings	100%	25%	-	Insufficient data	Insufficient data
Chemical Injection Pumps	75%	40%	57%	80%	100%
LDAR	90%	90%	94%	100%	100%

The results obtained from the survey generally indicated a high level of WRBP implementation. The scores for different WRBP categories are given in Figure 53. The highest WRBP was found to be associated with the LDAR program. The implementation level for this program among the surveyed facilities ranged between 90% and 100%. This is likely due to the Energy and Resource Conservation Board's (ERCB's) efforts to regulate fugitive emissions under Directive D60 (ERCB, 2006), which will require implementation of a Fugitive Emissions Management Plan by 31st December 2009 in Alberta. As such, this measure has become a standard practice and does not contribute to long term potential in waste reduction. WRBPs associated with pipelines ranked second highest.

Due to a combination of regulatory and industry efforts to address waste reduction it is unsurprising that the implementation of WRBPs is considerably higher than that of energy use reduction measures (TBPs and MBPs).

9.0 Barriers to Implementation of Energy Efficiency Projects

Although TBPs may make business sense, they will not always be implemented. For example high efficiency incinerators are a TBP that has been both a) proven and b) available for many years, and could greatly reduce fuel or natural gas usage in the UOG sector (as earlier noted, incineration represents 21% of the total energy usage in the sector). While internationally this TBP has been well accepted, it has been installed at a very few facilities in Canada. This kind of experience implies that there are a number of general barriers to the implementation of any energy efficiency project in the UOG sector. From interactions and discussions with companies over many years of working in the field of energy management, during the recruitment phase of this project, and through surveys performed by the Petroleum Technology Alliance Canada (PTAC) and noted in a PTAC-TEREE Report (PTAC-TEREE, 2009), the barriers to implementation cover a broad spectrum of issues, as outlined below. Many of these barriers have to be addressed before there will be an increase in the implementation of energy efficiency within the UOG industry.

9.1 Attitude and Focus of the UOG Sector

In general, the UOG industry may be characterized as having a short term focus. This has been dictated by the financial markets which value their investments on cash flow and the size of their resource reserves. As a result, the focus of a typical UOG company is on exploration and development to increase reserves and the production of oil and gas. The environment and conservation of energy has therefore not been a priority and it is generally looked upon as a cost rather not a revenue generator. Indeed, the implementation of energy efficiency projects means potential interruptions in production and lost revenue and can therefore clash with the core focus of the company.

The implementation of new TBPs has therefore to be scheduled around planned facility turnarounds and shutdowns as otherwise the loss of production would greatly offset the savings benefits. Scheduled turnarounds or shutdowns usually happen every two to four years, reducing the window of opportunity for implementing TBPs. Furthermore, the primary focus of these stoppage-periods is equipment upgrades and preventative maintenance needed to sustain or increase production - due to that focus new energy efficiency technologies are not always considered.

9.2 Cost of Fuel Gas

Historically UOG companies have placed little or no value on the fuel gas used at facilities or flared, and this has been considered to be a free resource. This is exacerbated by a provincial royalty structure that discourages the reduction of oil and gas that is consumed at facilities: no royalties are applied to fuel gas that is used in the production or processing of gas or oil or flared. Conversely, when that fuel gas usage is reduced and the conserved gas is sent to the sales stream, royalties are applied, thus providing a disincentive to conserve. With little value placed on fuel gas, it is often poorly measured and reported, whether used as combustion fuel or flared. This creates a feedback loop in which companies do not realize how much of this resource is being wasted, and so the issue of fuel gas consumption subsequently receives little management attention.

However, it is worth noting that there has been recent attention paid to EE technologies that focus on reducing fuel gas and natural gas usage through efficient and effective energy usage and waste control, as in the Fuel Gas Management Best Practice series (CAPP et al, 2008).

9.3 Energy Conservation Policies

In the past number of years there has been inconsistency and uncertainty around energy conservation policies and regulations at all levels of government. There is no tax incentive or credits to encourage the implementation of energy conservation projects and technologies. Capital expenditures for energy efficiency projects are taxed with no means to offset the amount of tax as with, by contrast, the exploration and development tax incentives; this again reinforces the culture of exploration and production within the UOG sector.

9.4 Financial and Risk Perception

Many energy efficiency projects are small scale and cannot compete with large scale drilling and production projects for the attention of management. In addition, the returns of investment (ROI) on energy efficiency project are often determined to be low when compared to drilling and production project forecasts. Many companies do not factor in the risk level of success when evaluating and comparing all projects. For example, exploration drilling projects have a much lower level of success than the implementation of an energy efficiency/conservation project. Financial incentives for implementing energy efficiency projects are small and do not attract the interest of management. For example, the Industry Energy Audit Incentive program had a limited of $5000 which was too small to attract management attention.

There is a general perception that new energy efficiency technologies are unproven and thus risky. Companies are willing to invest in proven technologies that have a quick payback and do not interfere with production, but do not want to be on the "bleeding" edge, as borne out by the survey results of this project (see Section 5.3). The perception of energy efficiency technologies as being "oversold and underdelivering" has been created by the misapplication of certain technologies in the past (for example, the application and installation of variable speed drives on the wrong motors resulting in no identifiable energy savings or problem side effects due to harmonic generation from the devices that caused plant shut downs).

9.5 Lack of Information and Resources

Finally, barriers are also in place due to the existing conditions and resources within companies in relation to energy efficiency, as confirmed by this study both during the recruitment phase and in the analysis of MBP implementation. There is a lack of energy efficiency awareness/ education and skills within some large and many intermediate and junior UOG companies. This lack of education means that companies and personnel are not aware of available funding or of conservation technologies. Even where there is knowledge, there is often a lack of staff resources to evaluate opportunities and implement new technologies and procedures. Many UOG facilities do not have sufficient measurement instrumentation at their facilities to determine energy usage, evaluate opportunities or be able to demonstrate the results of the implementation of energy efficiency projects and technologies.

9.6 Hetereogenity of Asset Base

As previously noted, the UOG sector is extremely varied. The assets owned by an individual company may span several sub-sectors and facilities with different processes, feed stock compositions, available infrastructure, etc. As such, it can be difficult to program energy efficiency upgrades across an asset base and small scale energy efficiency technologies that can be applied to many facilities in the UOG sector are not considered or are assigned a low priority.

As suggested by the results of this study, and in line with the project team's own experience, energy efficiency technologies are most likely to be implemented at large facilities where:

- Consumption of fuel gas, natural gas and electricity is sizable
- Measurement and monitoring is in place to identify energy usage levels and patterns
- The monetary magnitude of the savings benefit can attract management attention, and
- There are engineering and operating staff available and on site daily to promote, monitor and sustain the savings benefits.

This scenario excludes the thousands of small to medium size UOG facilities that have no full time operating staff on site.

10.0 Summary and Conclusions

The study involved primary data gathered from 30 facilities, representing 15 companies across a range of types (majors, trusts and intermediates/juniors). A total of 48 TBPs and 20 WRBPs were assessed, in addition to a facility and corporate-level assessment of MBPs. Although the results of the study should be treated with caution at a sub-sector level, it can be stated with some confidence that they are reasonably representative of the UOG sector as a whole. Some of the key findings of the study are:

- The technical potential for energy savings in the UOG sector is 16% by 2030. This represents a saving of 186 PJ of energy compared to the Reference Case. It is estimated that a further 128 PJ could be saved from adoption of high-efficiency incinerators to replace flares, dehydrator regenerators and existing incinerators throughout Canada but further modeling should be carried out to confirm this figure.

- The economic potential – assuming that only those TBPs that are economically acceptable to society are implemented – is 13% by 2030, or a saving of 147 PJ of energy compared to the Reference Case. Additional incineration savings could also be realized. These were not modeled as part of this study but due to their considerable potential, should be address within a future study.

- The largest absolute energy savings potential is in the Bitumen sub-sector, due to its high rate of anticipated growth to 2030. The largest percentage savings is in the Conventional Heavy Oil sub-sector.

- These savings represent only that which could be achieved by the TBPs assessed in this study. Further savings could be realized through improved design practices in the construction of new plants and through the earlier adoption of cutting edge technologies, which are traditionally resisted by the UOG sector until they are firmly proven in the field. Demonstration projects for new technologies are therefore likely to be an important method for encouraging greater efficiency.

- Direct fired heaters and steam boilers together, with 65% of the total energy use have the highest energy consumption, followed by incinerators with 21% energy use. The implementation of TBPs for direct fired heaters/steam boilers was generally low, and as such, process heating offers by far the highest level of both technical and economic energy efficiency potential. Efforts to reduce energy consumption and improve efficiency in the UOG sector should therefore focus on this area.

- Similar TBPs were found to have different level of implementation from one sub-sector to another, which may suggest an opportunity for transferring success stories across sub-sectors, but may also be indicative of barriers to implementation that are sub-sector-specific. However, more research would be required to investigate this issue due to the low number of facilities included at the sub-sector level.

- For each sub-sector, there were a number of TBPs that were 100% implemented. These measures are likely to have become mainstream practices and should not be included in future studies. However, one should be cautious in this interpretation because of an insufficient statistical reliability due to the low level of industry participation in this study. Nevertheless, this does indicate that the UOG industry is receptive to adopting proven energy efficiency measures.

- The Natural Gas Producers (Sour) sub-sector scored the highest in MBP with 54% implementation while Light and Medium Oil scored the lowest with 20% implementation. There is clearly much room for improving energy efficiency management within the UOG sector, particularly in the areas of policy and planning, training and capacity building. In themselves, these activities may not directly save much energy. However, they will provide a solid platform for companies to launch systematic, targeted and effective implementation of TBPs.

- Some companies have a high level of MBP implementation (up to 81% in the sample studied). The potential therefore exists to work with these companies to provide demonstrable leadership to their peers regarding the benefits of energy management and the practical lessons on how to implement it at a company or facility. This could also help overcome UOG sector reluctance to 'pilot' or 'cutting edge' best practices.

- Waste reduction best practices have a higher level of market penetration than the energy efficiency best practices, probably due to the regulatory environment around flaring, venting and fugitive emissions in Alberta.

- Water produced did not show a conclusive trend as half of the companies did not report on water production. However, this is known to be an important parameter affecting energy consumption and future studies should take this into account.

- There are significant barriers to the implementation of energy efficiency in the UOG sector, including a short-term focus, lack of information/resources to tackle energy efficiency, a culture of risk avoidance, suspicion of government and specific financial disincentives to conserve energy. These barriers must be addressed if energy efficiency is to be improved.

11.0 Acknowledgements

The project team would like to gratefully acknowledge the following, without whom this project could not have been completed:

- The various individual's at the participating companies and facilities who completed or assisted with the TBP and MBP surveys
- The project Steering Committee: Karen Mousseau, Louis-Philippe Désilets, Vaughn Munro and Angelo Mangatal of NRCan's Office of Energy Efficiency; Paul Slobodnik, ConocoPhillips; Alberta Alva-Argaez and Theo de Bruijn of CanmetENERGY
- Richard Leslie, Brad Herald, Kendall Dilling and Teresa Jackson of CAPP
- Gary Leach of SEPAC
- Canadian Heavy Oil Association
- The following individuals who supplied information on the provincial facility inventory for the UOG sector in Canada:
    - Dave Hawkins, Canada-Newfoundland Offshore Petroleum Board;
    - Jean-Yves Laliberte, Direction du developpement des hydrocarbures, Gouvernement du Québec
    - Keith Endresen and Wayne Osborne, Minerals and Petroleum Development Branch, New Brunswick Department of Natural Resources
    - Keith Lowden and Paul Legare, Science, Technology, Energy and Mines, Government of Manitoba
    - Mike Seinen and James Gladysz, BC Oil and Gas Commission
    - Pat Heuck, Saskatchewan Ministry of Energy and Resources, Government of Saskatchewan
    - Richard Corbet, Government of the Yukon
    - Rudy Rubansky, Petroleum Resources Centre, Government of Ontario
    - Stuart Pinks, Tim Church and Gerald Sheenan, Canada-Nova Scotia Offshore Petroleum Board
    - Zaka Ullah, Mineral, Oil and Gas Division, Government of North West Territories

12.0 References

Alberta Energy (2009) [WWW], Alberta Energy Website, Available at: http://www.energy.gov.ab.ca/, [Accessed: 6th April 2009]

ARPEL (2000), Energy Efficiency for Pumps, Compressors, Fans, Blowers and Turbines. ARPEL, Uruguay

ARPEL (2000), Energy Management of Steam Systems. ARPEL, Uruguay

ARPEL (2000), Evaluation of Energy Related Projects. ARPEL, Uruguay

ARPEL (2000), Optimization of Combustion in Boilers and Furnaces. ARPEL, Uruguay

ARPEL (2002), Energy Use Monitoring and Tracking. ARPEL, Uruguay

ARPEL (2003), On-Site Generation of Electricity. ARPEL, Uruguay

ARPEL (2005), Gas Flaring, Venting, Leaks and Losses at Exploration and Production Facilities. ARPEL, Uruguay

ARPEL (2005), Management of Energy and Energy-Related Air Emissions. ARPEL, Uruguay
BP (2009) [WWW], Canada -Energy Efficient Gas Production in Western Canada, Available at: http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/C/Canada_Energy_efficient_gas_production.pdf, [Accessed: 6th April 2009]

Baldor Electric Motors (2009) [WWW], Baldor Website, Available at: http://www.baldor.com/, [Accessed: 22nd December 2009] and 501Baldor CD-ROM Catalog Version10.0

Canadian Association of Petroleum Producers (CAPP) (2007), A Recommended Approach to Completing the National Pollutant Release Inventory (NPRI) for the Upstream Oil and Gas Industry. CAPP, Calgary

Canadian Association of Petroleum Producers (CAPP) (2007), Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities. CAPP, Calgary

Canadian Association of Petroleum Producers (CAPP) et al (2008), Fuel Gas Best Management Practices Series, Modules 0 – 17, CAPP, Calgary

Canadian Association of Petroleum Producers (CAPP) (2009), 2008 CAPP Stewardship Report. CAPP, Calgary

Canadian Association of Petroleum Producers (CAPP) (2009a) [WWW], CAPP Website, Available at: http://www.capp.ca/Pages/default.aspx, [Accessed: 6th April 2009]
Canadian Association of Petroleum Producers (CAPP) (2009b) [WWW], Greenhouse Gas Emissions, Available at: http://www.capp.ca/environmentCommunity/airClimateChange/Pages/GreenhouseGasEmissions.aspx, [Accessed: 6th April 2009]

Canadian Centre for Energy Information (2009) [WWW], Canadian Centre for Energy Information Website, Available at: http://www.centreforenergy.com/linksGenerator.asp?absKey=links_ungandtemplate=1,12, [Accessed: 6th April 2009]

Canadian Environmental Technology Advancement Centre (CETAC) (2009) [WWW], CETAC-West, Available at: http://www.cetacwest.com/index.html, [Accessed: 6th April 2009]

Canadian Standards Association (CSA) (2009) [WWW], Canadian GHG Challenge Registry, Available at: http://www.ghgregistries.ca/challenge/cha_sector_e.cfm?sect=43, [Accessed: 6th April 2009]

CETAC-West (2005), Energy Conservation Solutions In The Upstream Oil And Gas Industry: An Eco-Efficiency Pilot 2002-2005. CETAC-West, Calgary

CETAC-West (2008), Fuel Gas Best Management Practices: Fuel Gas Measurement and Reporting. CETAC-West, Calgary

Croteau, P (2007) [WWW], Petro-Canada Oil and Gas: Fire-Tube Immersion Heater Optimization Program and Field Heater Audit Program, Available at: http://www.northernstar.ab.ca/ftp/images/pres/Phil%20Croteau%20Presentation.pdf, [Accessed: 6th April 2009]

Delta Transformers (2009) [WWW], Product Family, Available at: http://www.delta.xfo.com/en/content/produits/Produits_famille.aspx, [Accessed: 6th April 2009]

Energy and Resources Conservation Board (ERCB) (2006), Directive D060: Upstream Petroleum Industry Flaring, Incinerating and Venting, ERCB, Calgary.

Energy Star (2009) [WWW], Energy Star for Industry, Available at: http://www.energystar.gov/index.cfm?c=industry.bus_industry, [Accessed: 6th April 2009]

Environment Canada (2006), Canada's 2006 Greenhouse Gas Inventory. Environment Canada, Ottawa

Gas Processing Association Canada (GPAC) (2009) [WWW], Gas Processing Association Canada Website, Available at: http://www.gpacanada.com/, [Accessed: 6th April 2009]

Husky Energy Inc. (Unknown), Husky Lloydminster Upgrader. Husky Energy Inc., Calgary

In Situ Oil Sands Alliance (IOSA) (2009) [WWW], IOSA Website, Available at: http://www.iosa.ca/, [Accessed: 6th April 2009]

Lloydminster Oilfield Technical Society (2009) [WWW], Upgrader Hydrogen Plant, Available at: http://www.lloydminsterheavyoil.com/upgradhydrogen.htm, [Accessed: 6th April 2009]
Methane to Markets (2009), Production/Processing Best Practices: Natural Gas Dehydrator and Pneumatic Controller Optimization for Methane Emission Reductions. Methane to Markets, 2009

mhd Systems (2009) [WWW], Innovative Scale Control and Fuel Saving Technologies, Available at: http://www.mhdsystems.com/, [Accessed: 6th April 2009]

NATCO Group (2009) [WWW], Firetube Turbulator, Available at: http://www.natcogroup.com/PDFContent/Consulting-Research/TechnicalPapers/NATCO-Turbulator.pdf, [Accessed: 6th April 2009]

NATCO Group (2009) [WWW], High Efficiency Phase Separator, Available at: http://www.natcogroup.com/Content.asp?t=ProductPageandProductID=30, [Accessed: 6th April 2009]

National Energy Board (2009), 2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020 - An Energy Market Assessment. NEB, Calgary

Natural Resources Canada (NRCan) (2006), Canada's Energy Outlook: The Reference Case 2006. NRCan, Ottawa

Natural Resources Canada: CanmetENERGY (2009) [WWW], Oil Sands: Upgrading Oil Sands and Heavy Oil: Upgrading and Refining Process Development, Available at: http://canmetenergy.nrcan.gc.ca/eng/oil_sands/upgrading/process_development.html, [Accessed: 6th April 2009]

Natural Resources Canada: Office of Energy Efficiency (2009) [WWW], Canadian Industry Program for Energy Conservation (CIPEC), Available at: http://www.oee.nrcan.gc.ca/industrial/cipec.cfm, [Accessed: 6th April 2009]

NRCan: Office of Energy Efficiency (2006), Case Study: Syncrude Canada Ltd. Optimizing Waste Heat Recovery at an Oil Sands Operation. NRCan, Ottawa

Petrobank Energy (2009) [WWW], Bitumen Extraction/Recovery Technology, Available at: http://www.petrobank.com/hea-whitesandsproject.html, [Accessed: 6th April 2009]

Petroleum Technology Alliance Canada (PTAC) and Deep Blue Associates (2005), Barriers to the Deployment of Environmental Technologies in the Upstream Oil and Gas Industry. PTAC, Calgary

Petroleum Technology Alliance Canada (PTAC) and New Paradigm Engineering Ltd (2006), Business Case for Energy Efficiency in the Upstream Oil and Gas Industry. PTAC, Calgary

Petroleum Technology Alliance Canada (PTAC) (2005), Technology for Emission Reduction and Eco-Efficiency (TEREE) Phase II. PTAC, Calgary

Petroleum Technology Alliance Canada (PTAC) (2009a) [WWW], Energy Efficiency Resources, Available at: http://www.ptac.org/iei1.html, [Accessed: 6th April 2009]

Petroleum Technology Alliance Canada (PTAC) (2009b) [WWW], Energy Efficiency, Available at: http://www.ptac.org/techeeat.html, [Accessed: 6th April 2009]

Petroleum Technology Alliance Canada (PTAC) (2009c) [WWW], Facilitating Innovation, Technology Transfer and Collaborative R and D in the Upstream Oil and Gas Industry, Available at: http://www.ptac.org/eea/dl/eeat0601p.pdf, [Accessed: 6th April 2009]

Petroleum Technology Alliance Canada (PTAC-TEREE) (2009) [WWW], Emission Reduction/ Eco-Efficiency, Available at: http://www.ptac.org/eet/eetteree.html, [Accessed: 6th April 2009]

Petroleum Technology Transfer Council (PTTC) (2004), Case Studies of Power Consumption Reduction in California Oilfields. PTTC, Los Angeles

Questor Technology Inc. (2009) [WWW], Economic and Effective Waste Gas Incineration, Available at: http://www.questortech.com/, [Accessed: 6th April 2009]

Robinson, D (2007) "Methane Savings from Dehydrators and Compressors", CETAC-West Conference 2007, Jan 15th – 17th, 2007.

Small Explorers and Producers Association of Canada (SEPAC) (2009) [WWW], SEPAC Website, Available at: http://www.sepac.ca/, [Accessed: 6th April 2009]

Somar Integra (2009) [WWW], Intelligent Motor Control, Available at: http://www.somar.co.uk/energy_saving_technology/energy_saving.php?Pageid=2, [Accessed: 6th April 2009]

Treasury Board of Canada Secretariat (2007), Canadian Cost-Benefit Analysis Guide – Regulatory Proposals, Treasury Board of Canada Secretariat, Ottawa

US Department of Energy (2009) [WWW], Industrial Technologies Program: A New Generation of Smart, Integrated Burner/ Fired-Heater Systems, Available at: http://www1.eere.energy.gov/industry/combustion/pdfs/processheatersystem.pdf, [Accessed: 6th April 2009]

US Department of Energy (2009) [WWW], Industrial Technologies Program: Advanced

Reciprocating Engine Systems (ARES), Available at: http://www1.eere.energy.gov/industry/distributedenergy/pdfs/recip_engines_brochure.pdf, [Accessed: 6th April 2009]

US Department of Energy (2009) [WWW], Industrial Technologies Program: Case Study - The Challenge: Improving the Performance of Oil Well Pumping Units, Available at: http://www1.eere.energy.gov/industry/bestpractices/case_study_oil_well.html, [Accessed: 6th April 2009]

US Department of Energy (2009) [WWW], Industrial Technologies Program: Improving Pumping System Performance: A Sourcebook for Industry, Available at: http://www1.eere.energy.gov/industry/bestpractices/pdfs/pump.pdf, [Accessed: 6th April 2009]

US Department of Energy (2009) [WWW], Industrial Technologies Program: Pumping Tip Sheets, Available at: http://www1.eere.energy.gov/industry/bestpractices/tip_sheets_pumps.html, [Accessed: 6th April 2009]

US Department of Energy (2009f) [WWW], Industrial Technologies Program, Available at: http://www1.eere.energy.gov/industry/about/, [Accessed: 6th April 2009]

US Department of Energy (2009g) [WWW], Petroleum Best Practices Plant-Wide Assessment Case Study: Paramount Petroleum: Plant-Wide Energy Efficiency Assessment Identified Three Opportunities, Available at: http://www1.eere.energy.gov/industry/bestpractices/pdfs/petrol_cs_paramount_petroleum.pdf, [Accessed: 6th April 2009]

US Department of Energy (2009h) [WWW], Plant Profiles: Industrial Energy Management In Action, Available at: http://www1.eere.energy.gov/industry/bestpractices/pdfs/plantprofiles.pdf, [Accessed: 6th April 2009]

US Environmental Protection Agency (EPA) (2004), Recover Gas from Pipeline Pigging Operations. US EPA, Washington

US Environmental Protection Agency (EPA) (2004), Replace Glycol Dehydration Units with Methanol Injection. US EPA, Washington

US Environmental Protection Agency (EPA) (2004), Use Inert Gases and Pigs to Perform Pipeline Purges. US EPA, Washington

US Environmental Protection Agency (EPA) (2005), Efficient Pigging of Gathering Lines. US EPA, Washington

US Environmental Protection Agency (EPA) (2006), Optimize Glycol Circulation And Install Flash Tank Separators In Glycol Dehydrators. US EPA, Washington

US Environmental Protection Agency (EPA) (2006), Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance. US EPA, Washington

US Environmental Protection Agency (EPA) (2009a) [WWW], Methane to Markets Partnership, Available at: http://www.epa.gov/methanetomarkets/, [Accessed: 6th April 2009]

US Environmental Protection Agency (EPA) (2009b) [WWW], Natural Gas Star Program, Available at: http://www.epa.gov/gasstar/, [Accessed: 6th April 2009]

WOW Energies (2009) [WWW], WOW Energies Website, Available at: http://www.wowenergies.com/, [Accessed: 6th April 2009]

Ziff Energy Group (2009) [WWW], Elevating Operations Performance: Assisting Clients to Achieve Measurable Improvements, Available at: http://www.ziffenergy.com/download/brochure/elevatingopsperf.pdf, [Accessed: 6th April 2009]

Appendix A

TRC Test Results for Economic Potential Scenario

Figure A1: Total Resource Cost Test and Relevant Parameters

The economic benefit cost test used in the study is the Total Resource Cost test (TRC) which calculates the net present value (NPV) of the benefit and cost streams associated with energy efficiency measure investments according to the following equation:
TRC = NPV(Annual Avoided Fuel, Electricity and Water Costs) – Capital Costs – NPV(Annual O&M Costs)

If the TRC is positive, then the net benefits of the measure outweigh the costs, and the measure should be implemented. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate.

The TRC test benefits cash flow stream is based on a valuation of what are referred to as the "avoided costs", i.e., the benefit to society of not having to supply the next, marginal unit of energy supply, such as a kW electricity or m3 of natural gas. For electricity, for example, supply costs include energy costs, and generation, transmission and distribution capacity.

The avoided costs to be used in the assessment are provided below.
A real discount rate of 8% will be used in economic calculations. This rate is recommended by the Treasury Board of Canada Secretariat.

Supply	Source of Information and Assumptions	Base Year Prices (2007)
Natural Gas	National Energy Board Energy Futures 2009 Report reference case natural gas price	$5.68
Electricity	Avoided cost provided by Ontario Power Authority	$15.98
Other	$4/GJ assumed for Base Year (Stantec/Marbek project team). For reference case growth rates similar to natural gas was assumed.	$4.00

Figure A-2: Net Present Values of Avoided Supply Cost

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Electricity	$15.07	$13.55	$27.76	$41.11	$52.85	$64.20	$75.09	$84.99	$94.04	$102.28	$109.85	$116.77
Natural Gas	$11.66	$13.49	$22.35	$31.07	$40.51	$49.26	$57.39	$64.91	$71.85	$78.28	$84.22	$89.71
Fuel Gas	$14.79	$18.73	$29.44	$41.21	$54.06	$66.20	$77.67	$88.29	$98.12	$107.22	$115.65	$123.44
Other	$3.14	$3.81	$7.08	$10.06	$12.95	$15.64	$18.14	$20.45	$22.59	$24.57	$26.40	$28.09
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electricity	$123.06	$128.85	$134.59	$139.88	$144.77	$149.28	$153.44	$157.28	$160.83	$164.10	$167.11	$169.90
Natural Gas	$94.80	$99.51	$104.19	$108.52	$112.53	$116.24	$119.67	$122.86	$125.80	$128.53	$131.06	$133.40
Fuel Gas	$130.66	$137.36	$144.01	$150.17	$155.88	$161.17	$166.07	$170.61	$174.81	$178.71	$182.32	$185.66
Other	$29.67	$31.12	$32.57	$33.91	$35.15	$36.29	$37.36	$38.34	$39.26	$40.10	$40.89	$41.61

Figure A-3: TRC Test Results for Economic Potential Scenario for Natural Gas Producers

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$10,929	Pass	0.4
System	Power factor > 95%	$4,815	Pass	0.5
Heating	Line heater operating practices (seasonal)	$326,476	Pass	0.1
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$61,334	Fail	10.9
Heating	Oil treater temperature control to avoid over heating and over treating	$158,958	Pass	0.1
Heating	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	$32,143	Pass	0.1
Cooling	Optimized automated condenser control	$205,505	Pass	1.2
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	$2,110,275	Pass	0.1
Engines/ Gas turbines	Improvement of engine operation	$5,743,152	Pass	0.3
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$471,271	Pass	6.8
Air Compressors	Annual air leak detection and repair program	$5,621	Pass	1.1
Air Compressors	Intake air temperature reduction	$3,329	Pass	1.7

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Pumps	Pump selection in lead/ lag or primary/secondary	$70,287	Pass	0.1
Pumps	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	-$505	Fail	2.5
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-$25,686	Fail	6.4
Pumps	Gathering Systems - Introduce site measurements to improve energy efficiency	-$14,538	Fail	48.4
Pumps	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	-$337	Fail	2.5
Fans/Blowers	Two speed motors or variable speed drives	$59,666	Pass	0.9
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$13,174	Pass	1.7
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	$392,175	Pass	0.1
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$585,632	Pass	Negative (-)*

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	$263,087	Pass	0.1
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	$109,147	Pass	1.0
Gas Compressors	Inlet and Interstage cooling	$341,028	Pass	11.7
Gas Compressors	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	$5,596	Pass	1.9
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	$409,131	Pass	Negative (-)*
Gas Compressors	Gathering Systems - Introduce site measurements to improve energy efficiency	$83,089	Pass	36.6

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Figure A-4: TRC Test Results for Economic Potential Scenario for Natural Gas Processors - Sweet

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$32,272	Pass	0.1
System	Power factor > 95%	$15,378	Pass	0.1
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	-$430,316	Fail	37.6
Heating	Improved design practices and conversion from natural draft to forced air systems.	$318,156	Pass	Negative (-)*
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	$207,561	Pass	0.7
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$61,334	Fail	12.6
Heating	Annual steam trap surveys and repair	$38,905	Pass	4.2
Heating	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	$32,143	Pass	0.1
Heating	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	$28,794	Pass	Negative (-)*

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Heating	Fractionation - Fractionation unit evaluated and monitored to ensure good performance	-$761	Fail	2.8
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	-$761	Fail	2.8
Cooling	Use sub-cooler to increase percent liquid entering chiller	$12,202	Pass	13.8
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	$138,866	Pass	1.3
Cooling	Optimized automated condenser control	$205,505	Pass	0.4
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	$2,110,275	Pass	0.1
Engines/ Gas turbines	Improvement of engine operation	$5,743,152	Pass	0.4
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$471,271	Pass	8.8
Air Compressors	Annual air leak detection and repair program	$5,621	Pass	1.1
Air Compressors	Intake air temperature reduction	$3,329	Pass	1.7
Pumps	Pump selection in lead/ lag or primary/secondary	$62,205	Pass	0.1
Pumps	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	-$505	Fail	2.4

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Pumps	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	$2,685	Pass	426.1
Pumps	Fractionation - Fractionation unit evaluated and monitored to ensure good performance	-$8,923	Fail	47.3
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	-$8,923	Fail	47.3
Fans/Blowers	Two speed motors or variable speed drives	$44,567	Pass	1.1
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$8,996	Pass	2.2
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$585,632	Pass	Negative (-)*

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Figure A-5: TRC Test Results for Economic Potential Scenario for Natural Gas Processors - Sour

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$445,483	Pass	0.0
System	Power factor > 95%	$218,489	Pass	0.0
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	$1,605,504	Pass	3.7
Heating	Improved design practices and conversion from natural draft to forced air systems.	$276,276	Pass	Negative (-)*
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	$165,681	Pass	0.8
Heating	Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	$61,291	Pass	5.3
Heating	Boiler blowdown optimisation	$41,018	Pass	5.7
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$95,624	Fail	14.3
Heating	Annual steam trap surveys and repair	$25,303	Pass	4.8
Cooling	Use sub-cooler to increase percent liquid entering chiller	$21,254	Pass	27.2

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	$154,541	Pass	2.6
Cooling	Optimized automated condenser control	$228,136	Pass	0.8
Engines/ Gas turbines	Improvement of engine operation	$ 6,263,655	Pass	0.4
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$ 549,346	Pass	7.7
Air Compressors	Annual air leak detection and repair program	$ 7,037	Pass	1.0
Air Compressors	Intake air temperature reduction	$ 3,860	Pass	1.6
Pumps	Pump selection in lead/ lag or primary/secondary	$ 76,753	Pass	0.1
Pumps	Sulphur Recovery - Optimize SRU performance	-$72,577	Fail	58.1
Fans/Blowers	Two speed motors or variable speed drives	$65,706	Pass	0.9
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$14,845	Pass	1.7
Fans/Blowers	Sulphur Recovery - Optimize SRU performance	-$48,099	Fail	18.0
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	$412,481	Pass	0.3
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	$427,908	Pass	0.1

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$602,133	Pass	Negative (-)*
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	$286,909	Pass	0.1
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	$119,294	Pass	0.7
Gas Compressors	Acid Gas Injection - Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.	$14,270	Pass	0.3

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Figure A-6: TRC Test Results for Economic Potential Scenario for Light and Medium Oil

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$2,892	Pass	1.1
System	Power factor > 95%	$1,081	Pass	1.6
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	-$574,640	Fail	549.2
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$61,334	Fail	10.0
Heating	Oil treater temperature control to avoid over heating and over treating	$158,958	Pass	0.1
Heating	Annual steam trap surveys and repair	$38,905	Pass	3.3
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$471,271	Pass	8.5
Pumps	Pump selection in lead/ lag or primary/secondary	$70,287	Pass	0.1
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-$25,686	Fail	5.6
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	$376,748	Pass	0.2
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	$392,175	Pass	0.1

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$585,632	Pass	Negative (-)*
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	$109,147	Pass	0.5
Gas Compressors	Inlet and Interstage cooling	$341,028	Pass	6.2
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	$409,131	Pass	Negative (-)*

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Figure A-7: TRC Test Results for Economic Potential Scenario for Conventional Heavy Oil

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	$511	Pass	2.6
System	Power factor > 95%	-$197	Fail	3.9
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	-$586,686	Fail	1,338.0
Heating	Improved design practices and conversion from natural draft to forced air systems.	$401,914	Pass	Negative (-)*
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	$291,320	Pass	0.5
Heating	Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	$115,136	Pass	3.0
Heating	Line heater operating practices (seasonal)	$422,200	Pass	0.0
Heating	Boiler blowdown optimisation	$73,936	Pass	3.3
Heating	Use of energy efficient fired heaters (burners) with improved controls	$7,245	Pass	8.1
Heating	Annual steam trap surveys and repair	$66,109	Pass	2.7

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	$1,668	Pass	1.8
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	$2,110,275	Pass	0.1
Engines/ Gas turbines	Improvement of engine operation	$5,743,152	Pass	0.4
Engines/ Gas Turbines	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	$854,106	Pass	0.0
Engines/ Gas Turbines	Oilfield Pumping - Perform routine testing and correction of abnormalities	$170,865	Pass	0.0
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$471,271	Pass	8.8
Air Compressors	Annual air leak detection and repair program	$5,621	Pass	1.1
Air Compressors	Intake air temperature reduction	$3,329	Pass	1.7
Pumps	Pump selection in lead/ lag or primary/secondary	$70,287	Pass	0.1
Pumps	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	-$505	Fail	2.1
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-$25,686	Fail	5.3

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Pumps	Gathering Systems - Introduce site measurements to improve energy efficiency	-$14,538	Fail	40.0
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	-$8,880	Fail	42.1
Fans/Blowers	Two speed motors or variable speed drives	$59,666	Pass	0.9
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$13,174	Pass	1.7
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	$376,748	Pass	0.1
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	$392,175	Pass	0.0
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$585,632	Pass	Negative (-)*
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	$109,147	Pass	0.3
Gas Compressors	Inlet and Interstage cooling	$341,028	Pass	3.6
Gas Compressors	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	$5,596	Pass	0.6

Enduse	Enduse	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	$ 409,131	Pass	Negative (-)*

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Figure A-8: TRC Test Results for Economic Potential Scenario for Bitumen

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	$10,711,746	Pass	0.7
Heating	Improved design practices and conversion from natural draft to forced air systems.	$318,156	Pass	Negative (-)*
Heating	Installation of economizer	-$105,425	Fail	9.4
Heating	Use of energy efficient fired heaters (burners) with improved controls	-$61,334	Fail	9.4
Heating	Annual steam trap surveys and repair	$38,905	Pass	3.1
Heating	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	$28,794	Pass	Negative (-)*
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	-$761	Fail	2.1
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	$2,110,275	Pass	0.1
Engines/ Gas Turbines	Utilization of waste heat from exhaust	$471,271	Pass	6.2
Air Compressors	Annual air leak detection and repair program	$5,621	Pass	1.1
Air Compressors	Intake air temperature reduction	$3,329	Pass	1.7
Pumps	Pump selection in lead/ lag or primary/secondary	$70,287	Pass	0.1

Enduse	Measure	TRC	TRC (Pass / Fail)	Simple Payback Period (Yrs)
Pumps	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	$2,756	Pass	378.8
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	-$8,880	Fail	42.1
Fans/Blowers	Two speed motors or variable speed drives	$48,342	Pass	1.1
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	$10,040	Pass	2.1
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	$287,416	Pass	0.2
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	$544,381	Pass	Negative (-)*
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	$203,532	Pass	0.0
Gas Compressors	Inlet and Interstage cooling	$236,675	Pass	4.4

*A negative payback indicates that the cost of the measure is less than the base technology. For example under right sizing for motors, the new motor will be smaller compared to installing the same size motor. The incremental cost is negative and the payback period is also negative.

Appendix B

Conversion Factors

Figure B-1: Energy Content Conversion Factors

Energy Source	Unit Conversion Applies To	Conversion Factor to GJ	Units	Reference
Electricity	kWh	0.0036	GJ/kW	National Energy Board (a)
Fuel Oil No. 2	m3	39	GJ/m3	National Energy Board (a)
Fuel Oil No. 6	m3	41	GJ/m3	National Energy Board (a)
Diesel (transport)	m3	39	GJ/m3	National Energy Board (a)
Gasoline (transport)	m3	35	GJ/m3	National Energy Board (a)
Propane	m3	26	GJ/m3	National Energy Board (a)
Natural gas	m3	0.0378	GJ/m3	Average of gas content values provided by Enbridge and Union Gas

(a) National Energy Board (Energy Conversion Tables at www.neb-one.gc.ca)
(b) Statistics Canada (Energy Statistics Handbook – Fourth Quarter 2008)

Appendix C

References for Base Year and Reference Case Energy Use

Figure C-1: Oil and Gas Industries Energy Consumption by Fuel

Oil and Gas Industries Energy Consumption by Fuel (Gigajoules)						
	2005	2010	2015	2020	2025	2030
Natural Gas Producers						
Production						
Natural Gas	214,040,183	179,305,457	173,823,555	174,080,380	174,453,781	174,827,182
Electricity	0	0	0	0	0	0
Processing						
Natural Gas	244,356,541	193,242,218	183,150,806	175,894,711	174,892,570	173,890,429
Electricity	12,656,794	9,905,052	8,361,143	7,419,063	7,308,470	7,197,877
LPGs	45,557,694	36,027,968	34,146,531	32,793,709	32,606,871	32,420,032
Flaring (Natural Gas)	13,006,926	9,783,111	9,271,679	8,904,976	8,854,311	8,803,645
Crude Oil Producers						
Light and Medium						
Natural Gas	50,074,637	68,097,115	82,304,696	95,140,324	97,684,235	100,228,145
Electricity	34,183,465	40,472,039	42,831,404	47,332,916	48,221,401	49,109,886
Flaring (Natural Gas)	32,319,633	37,927,407	40,619,820	43,207,466	43,719,538	44,231,610
Conventional Heavy						
Natural Gas – Corrected	11,194,465	12,943,711	13,391,883	12,623,019	12,415,574	12,208,129
Electricity – Corrected	4,599,753	5,023,191	5,010,487	4,694,499	4,618,236	4,541,972
Flaring (Natural Gas) - Corrected	5,340,594	6,490,107	6,714,825	6,329,309	6,225,294	6,121,279
Bitumen						
Natural Gas – Corrected	194,459,074	267,242,712	363,578,620	477,736,727	498,168,878	518,601,028
Electricity – Corrected	3,123,024	4,291,934	5,839,094	7,672,480	8,000,622	8,328,763
Flaring (Natural Gas) - Corrected	6,402,051	8,864,446	12,059,910	15,846,536	16,524,271	17,202,006
Synthetic (excluding mining)						
Still Gas – Corrected	113,070,983	166,244,563	247,456,500	325,148,686	341,116,646	357,084,606
Petroleum Coke - Corrected	67,227,677	106,799,877	158,551,530	210,729,346	221,560,041	232,390,735

Appendix D

Generic Plants Energy Use Profiles

Figure D-1: Generic Plant Profile for Natural Gas Producers

		NG Producers		
Area	Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	45%	70%
Cooling and Refrigeration	Refrigeration Compressors	0%	0%	2%
Drivers	Engines/ Gas Turbines	0%	29%	11%
	Motors	0%	0%	3%
Rotors	Air Compressors	28%	0%	0%
	Pumps	51%	0%	1%
	Fans/Blowers	21%	0%	0%
	Gas Compressors	0%	11%	13%
Tail Gas Incineration	Incinerators	0%	15%	0%
Total		100%	100%	100%

Figure D-2: Generic Plant Profile for Natural Gas Processors - Sweet

		NG Processors - Sweet		
Area	Level 4 - Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	0%	67%
Cooling and Refrigeration	Refrigeration Compressors	49%	0%	1%
Drivers	Engines/ Gas Turbines	0%	0%	12%
	Motors	0%	0%	0%
Rotors	Air Compressors	5%	0%	0%
	Pumps	21%	0%	0%
	Fans/Blowers	24%	0%	0%
	Gas Compressors	1%	0%	20%
Tail Gas Incineration	Incinerators	0%	0%	0%
Total		100%	0%	100%

Figure D-3: Generic Plant Profile for Natural Gas Processors - Sour

		NG Processors - Sour		
Area	Level 4 - Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	31%	64%
Cooling and Refrigeration	Refrigeration Compressors	2%	1%	1%
Drivers	Engines/ Gas Turbines	0%	2%	3%
	Motors	0%	0%	0%
Rotors	Air Compressors	5%	0%	0%
	Pumps	56%	0%	0%
	Fans/Blowers	27%	0%	0%
	Gas Compressors	10%	0%	2%
Tail Gas Incineration	Incinerators	0%	66%	30%
Total		100%	100%	100%

Figure D-4: Generic Plant Profile for Light and Medium Oil

		Light and Medium Oil		
Area	Level 4 - Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	84%	35%
Cooling and Refrigeration	Refrigeration Compressors	6%	0%	0%
Drivers	Engines/ Gas Turbines	0%	5%	33%
	Motors	0%	0%	11%
Rotors	Air Compressors	4%	0%	0%
	Pumps	78%	4%	6%
	Fans/Blowers	3%	2%	0%
	Gas Compressors	11%	6%	15%
Tail Gas Incineration	Incinerators	0%	0%	0%
Total		100%	100%	100%

Figure D-5: Generic Plant Profile for Conventional Heavy Oil

		Conventional Heavy Oil		
Area	Level 4 - Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	100%	98%
Cooling and Refrigeration	Refrigeration Compressors	0%	0%	0%
Drivers	Engines/ Gas Turbines	0%	0%	2%
	Motors	0%	0%	0%
Rotors	Air Compressors	1%	0%	0%
	Pumps	79%	0%	0%
	Fans/Blowers	12%	0%	0%
	Gas Compressors	8%	0%	0%
Tail Gas Incineration	Incinerators	0%	0%	0%
Total		100%	100%	100%

Figure D-6: Generic Plant Profile for Bitumen

		Bitumen		
Area	Level 4 - Equipment / Process	Electricity	Natural Gas	Fuel Gas
Direct Process Heating	Direct Fired Heaters/ Steam Boilers	0%	99%	100%
Cooling and Refrigeration	Refrigeration Compressors	0%	0%	0%
Drivers	Engines/ Gas Turbines	0%	1%	0%
	Motors	0%	0%	0%
Rotors	Air Compressors	4%	0%	0%
	Pumps	70%	0%	0%
	Fans/Blowers	24%	0%	0%
	Gas Compressors	3%	0%	0%
Tail Gas Incineration	Incinerators	0%	0%	0%
Total		100%	100%	100%

Appendix E

Reference Case Market Penetration Rates

Figure E-1: Market penetration rates for Natural Gas Producers[1]

			Reference Case Market Penetration Rates					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	17%	17%	18%	19%	20%	21%
System	Power factor > 95%	90%	8%	9%	9%	9%	10%	10%
Heating	Line heater operating practices (seasonal)	90%	17%	17%	18%	19%	20%	21%
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	17%	17%	18%	19%	20%	21%
Heating	Oil treater temperature control to avoid over heating and over treating	90%	33%	34%	36%	38%	40%	42%
Heating	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	90%	50%	52%	54%	57%	60%	63%

1 This list includes measures that passed the TRC test for technical potential. For a full list of measures per subsector refer to Exhibits 5.2 and 5.10

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Cooling	Optimized automated condenser control	90%	17%	17%	18%	19%	20%	21%
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	90%	83%	86%	90%	95%	99%	100%
Engines/ Gas turbines	Improvement of engine operation	90%	83%	86%	90%	95%	99%	100%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	17%	17%	18%	19%	20%	21%
Air Compressors	Annual air leak detection and repair program	90%	33%	34%	36%	38%	40%	42%
Air Compressors	Intake air temperature reduction	90%	33%	34%	36%	38%	40%	42%
Pumps	Pump selection in lead/lag or primary/ secondary	90%	33%	34%	36%	38%	40%	42%
Pumps	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	90%	83%	86%	90%	95%	99%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	83%	86%	90%	95%	99%	100%
Pumps	Gathering Systems - Hydrate formation mitigation is evaluated based on cost and emissions	90%	100%	100%	100%	100%	100%	100%
Pumps	Gathering Systems - Introduce site measurements to improve energy efficiency	90%	83%	86%	90%	95%	99%	100%
Pumps	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	90%	50%	52%	54%	57%	60%	63%
Fans/Blowers	Two speed motors or variable speed drives	90%	2%	3%	4%	5%	6%	7%
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	90%	17%	17%	18%	19%	20%	21%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	90%	83%	86%	90%	95%	99%	100%
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	67%	69%	72%	76%	79%	83%
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	90%	67%	69%	72%	76%	79%	83%
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	90%	67%	69%	72%	76%	79%	83%
Gas Compressors	Inlet and Interstage cooling	90%	83%	86%	90%	95%	99%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	90%	83%	86%	90%	95%	99%	100%
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	83%	86%	90%	95%	99%	100%
Gas Compressors	Gathering Systems - Hydrate formation mitigation is evaluated based on cost and emissions	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Gathering Systems - Introduce site measurements to improve energy efficiency	90%	83%	86%	90%	95%	99%	100%

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Figure E-2: Market penetration rates for Natural Gas Processors – Sweet

			Reference Case Market Penetration Rates					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	40%	41%	43%	45%	48%	50%
System	Power factor > 95%	90%	20%	21%	22%	23%	24%	25%
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	90%	40%	41%	43%	45%	48%	50%
Heating	Improved design practices and conversion from natural draft to forced air systems.	90%	2%	3%	4%	5%	6%	7%
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	90%	80%	82%	87%	91%	95%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	60%	62%	65%	68%	72%	75%
Heating	Annual steam trap surveys and repair	90%	40%	41%	43%	45%	48%	50%
Heating	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	90%	2%	3%	4%	5%	6%	7%
Heating	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	90%	40%	41%	43%	45%	48%	50%
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	40%	41%	43%	45%	48%	50%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Fractionation - Fractionation unit evaluated and monitored to ensure good performance	90%	40%	41%	43%	45%	48%	50%
Cooling	Use sub-cooler to increase percent liquid entering chiller	90%	40%	41%	43%	45%	48%	50%
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	90%	60%	62%	65%	68%	72%	75%
Cooling	Optimized automated condenser control	90%	60%	62%	65%	68%	72%	75%
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	90%	60%	62%	65%	68%	72%	75%
Engines/ Gas turbines	Improvement of engine operation	90%	40%	41%	43%	45%	48%	50%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	20%	21%	22%	23%	24%	25%
Air Compressors	Annual air leak detection and repair program	90%	40%	41%	43%	45%	48%	50%
Air Compressors	Intake air temperature reduction	90%	40%	41%	43%	45%	48%	50%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Pumps	Pump selection in lead/lag or primary/ secondary	90%	60%	62%	65%	68%	72%	75%
Pumps	Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	90%	2%	3%	4%	5%	6%	7%
Pumps	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	90%	60%	62%	65%	68%	72%	75%
Pumps	Fractionation - Fractionation unit evaluated and monitored to ensure good performance	90%	40%	41%	43%	45%	48%	50%
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	20%	21%	22%	23%	24%	25%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Fans/Blowers	Two speed motors or variable speed drives	90%	2%	3%	4%	5%	6%	7%
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	90%	2%	3%	4%	5%	6%	7%
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	60%	62%	65%	68%	72%	75%
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	90%	100%	100%	100%	100%	100%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Inlet and Interstage cooling	90%	100%	100%	100%	100%	100%	100%

Figure E-3: Market Penetration Rates for Natural Gas Processors – Sour

			Reference Case Market Penetration Rate					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	94%	97%	100%	100%	100%	100%
System	Power factor > 95%	90%	63%	64%	68%	71%	75%	78%
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	90%	2%	3%	4%	5%	6%	7%
Heating	Improved design practices and conversion from natural draft to forced air systems.	90%	63%	64%	68%	71%	75%	78%
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	90%	63%	64%	68%	71%	75%	78%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Increase/ improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	90%	25%	26%	27%	28%	30%	31%
Heating	Boiler blowdown optimisation	90%	50%	52%	54%	57%	60%	63%
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	13%	13%	14%	14%	15%	16%
Heating	Annual steam trap surveys and repair	90%	75%	77%	81%	85%	89%	94%
Cooling	Use sub-cooler to increase percent liquid entering chiller	90%	88%	90%	95%	99%	100%	100%
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	90%	75%	77%	81%	85%	89%	94%
Cooling	Optimized automated condenser control	90%	63%	64%	68%	71%	75%	78%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	90%	100%	100%	100%	105%	100%	100%
Engines/ Gas turbines	Improvement of engine operation	90%	38%	39%	41%	43%	45%	47%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	2%	3%	4%	5%	6%	7%
Air Compressors	Annual air leak detection and repair program	90%	75%	77%	81%	85%	89%	94%
Air Compressors	Intake air temperature reduction	90%	63%	64%	68%	71%	75%	78%
Pumps	Pump selection in lead/lag or primary/ secondary	90%	75%	77%	81%	85%	89%	94%
Pumps	Sulphur Recovery - Optimize SRU performance	90%	88%	90%	95%	99%	100%	100%
Fans/Blowers	Two speed motors or variable speed drives	90%	25%	26%	27%	28%	30%	31%
Fans/Blowers	Fan housing and air flow improvements and hub bells installed	90%	38%	39%	41%	43%	45%	47%
Fans/Blowers	Sulphur Recovery - Optimize SRU performance	90%	88%	90%	95%	99%	100%	100%

Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	88%	90%	95%	99%	100%	100%
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	90%	88%	90%	95%	99%	100%	100%
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	50%	52%	54%	57%	60%	63%
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	90%	63%	64%	68%	71%	75%	78%
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	90%	75%	77%	81%	85%	89%	94%
Gas Compressors	Inlet and Interstage cooling	90%	100%	100%	100%	100%	100%	100%
Gas Compressors	Acid Gas Injection - Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.	90%	19%	19%	20%	21%	22%	23%

Figure E-4: Market penetration rates for Light and Medium Oil

			Reference Case Market Penetration Rates					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	70%	72%	76%	79%	83%	88%
System	Power factor > 95%	90%	60%	62%	65%	68%	72%	75%
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	90%	2%	3%	4%	5%	6%	7%
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	40%	41%	43%	45%	48%	50%
Heating	Oil treater temperature control to avoid over heating and over treating	90%	80%	82%	87%	91%	95%	100%
Heating	Annual steam trap surveys and repair	90%	2%	3%	4%	5%	6%	7%
Engines/ Gas turbines	Improvement of engine operation	90%	0%	0%	0%	0%	0%	0%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Engines/ Gas Turbines	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	90%	100%	100%	100%	100%	100%	100%
Engines/ Gas Turbines	Oilfield Pumping - Perform routine testing and correction of abnormalities	90%	100%	100%	100%	100%	100%	100%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	2%	3%	4%	5%	6%	7%
Motors	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	90%	100%	100%	100%	100%	100%	100%
Motors	Oilfield Pumping - Perform routine testing and correction of abnormalities	90%	100%	100%	100%	100%	100%	100%
Air Compressors	Annual air leak detection and repair program	90%	100%	100%	100%	100%	100%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Pumps	Pump selection in lead/lag or primary/ secondary	90%	60%	62%	65%	68%	72%	75%
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	50%	52%	54%	57%	60%	63%
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	60%	62%	65%	68%	72%	75%
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	90%	60%	62%	65%	68%	72%	75%
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	80%	82%	87%	91%	95%	100%
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	90%	60%	62%	65%	68%	72%	75%
Gas Compressors	Inlet and Interstage cooling	90%	60%	62%	65%	68%	72%	75%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	40%	41%	43%	45%	48%	50%

Figure E-5: Market Penetration Rates for Conventional Heavy Oil

			Reference Case Market Penetration Rates					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	25%	26%	27%	28%	30%	31%
System	Power factor > 95%	90%	75%	77%	81%	85%	89%	94%
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	90%	2%	3%	4%	5%	6%	7%
Heating	Improved design practices and conversion from natural draft to forced air systems.	90%	0%	0%	0%	0%	0%	0%
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	90%	25%	26%	27%	28%	30%	31%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Increase/ improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	90%	2%	3%	4%	5%	6%	7%
Heating	Line heater operating practices (seasonal)	90%	2%	3%	4%	5%	6%	7%
Heating	Boiler blowdown optimisation	90%	2%	3%	4%	5%	6%	7%
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	75%	77%	81%	85%	89%	94%
Heating	Oil treater temperature control to avoid over heating and over treating	90%	100%	100%	100%	100%	100%	100%
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	2%	3%	4%	5%	6%	7%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Annual steam trap surveys and repair	90%	13%	13%	14%	14%	15%	16%
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	90%	50%	52%	54%	57%	60%	63%
Engines/ Gas turbines	Improvement of engine operation	90%	50%	52%	54%	57%	60%	63%
Engines/ Gas Turbines	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	90%	50%	52%	54%	57%	60%	63%
Engines/ Gas Turbines	Oilfield Pumping - Perform routine testing and correction of abnormalities	90%	75%	77%	81%	85%	89%	94%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	2%	3%	4%	5%	6%	7%
Motors	Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	90%	50%	52%	54%	57%	60%	63%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Motors	Oilfield Pumping - Perform routine testing and correction of abnormalities	90%	75%	77%	81%	85%	89%	94%
Air Compressors	Annual air leak detection and repair program	90%	50%	52%	54%	57%	60%	63%
Air Compressors	Intake air temperature reduction	90%	38%	39%	41%	43%	45%	47%
Pumps	Pump selection in lead/lag or primary/ secondary	90%	50%	52%	54%	57%	60%	63%
Pumps	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	90%	25%	26%	27%	28%	30%	31%
Pumps	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	25%	26%	27%	28%	30%	31%
Pumps	Gathering Systems - Introduce site measurements to improve energy efficiency	90%	0%	0%	0%	0%	0%	0%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	13%	13%	14%	14%	15%	16%
Fans/ Blowers	Two speed motors or variable speed drives	90%	2%	3%	4%	5%	6%	7%
Fans/ Blowers	Fan housing and air flow improvements and hub bells installed	90%	2%	3%	4%	5%	6%	7%
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	25%	26%	27%	28%	30%	31%
Gas Compressors	Set valve positions to run compressor at optimum efficiency and reduce bypass	90%	75%	77%	81%	85%	89%	94%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	25%	26%	27%	28%	30%	31%
Gas Compressors	Set cylinder clearance to a minimum to optimize compressor efficiency	90%	25%	26%	27%	28%	30%	31%
Gas Compressors	Inlet and Interstage cooling	90%	25%	26%	27%	28%	30%	31%
Gas Compressors	Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	90%	25%	26%	27%	28%	30%	31%
Gas Compressors	Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	90%	38%	39%	41%	43%	45%	47%

Figure E-6: Market Penetration Rates for Bitumen

			Reference Case Market Penetration Rates					
Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
System	Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	90%	100%	100%	100%	100%	100%	100%
System	Power factor > 95%	90%	100%	100%	100%	100%	100%	100%
System	Up-to-date DCS or PLC controls to optimize equipment run times and rates	90%	2%	3%	4%	5%	6%	7%
Heating	Improved design practices and conversion from natural draft to forced air systems.	90%	50%	52%	54%	57%	60%	63%
Heating	Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	90%	100%	100%	100%	100%	100%	100%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Increase/ improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	90%	100%	100%	100%	100%	100%	100%
Heating	Line heater operating practices (seasonal)	90%	100%	100%	100%	100%	100%	100%
Heating	Boiler blowdown optimisation	90%	100%	100%	100%	100%	100%	100%
Heating	Installation of economizer	90%	50%	52%	54%	57%	60%	63%
Heating	Use of energy efficient fired heaters (burners) with improved controls	90%	50%	52%	54%	57%	60%	63%
Heating	Oil treater temperature control to avoid over heating and over treating	90%	100%	100%	100%	100%	100%	100%
Heating	Annual steam trap surveys and repair	90%	0%	0%	0%	0%	0%	0%
Heating	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	90%	0%	0%	0%	0%	0%	0%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Heating	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	0%	0%	0%	0%	0%	0%
Cooling	Improve insulation to ensure at least 90% of insulation in very good condition	90%	2%	3%	4%	5%	6%	7%
Engines/ Gas Turbines	Improved performance monitoring, optimization and servicing practices	90%	2%	3%	4%	5%	6%	7%
Engines/ Gas Turbines	Utilization of waste heat from exhaust	90%	2%	3%	4%	5%	6%	7%
Air Compressors	Annual air leak detection and repair program	90%	50%	52%	54%	57%	60%	63%
Air Compressors	Intake air temperature reduction	90%	2%	3%	4%	5%	6%	7%
Pumps	Pump selection in lead/lag or primary/ secondary	90%	50%	52%	54%	57%	60%	63%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Pumps	Desiccant Dehydrators - Timely replacement of desiccant dehydrators	90%	2%	3%	4%	5%	6%	7%
Pumps	Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	90%	2%	3%	4%	5%	6%	7%
Fans/ Blowers	Two speed motors or variable speed drives	90%	50%	52%	54%	57%	60%	63%
Fans/ Blowers	Fan housing and air flow improvements and hub bells installed	90%	50%	52%	54%	57%	60%	63%
Gas Compressors	Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	90%	2%	3%	4%	5%	6%	7%

Enduse	Measure	Enduse Applicability	2005	2010	2015	2020	2025	2030
Gas Compressors	Right sizing to minimize recycling of gas and match inlet gas volume	90%	50%	52%	54%	57%	60%	63%
Gas Compressors	Volume pocket adjustments - manual or automatic to match inlet gas stream	90%	0%	0%	0%	0%	0%	0%
Gas Compressors	Inlet and Interstage cooling	90%	50%	52%	54%	57%	60%	63%

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

Appendix F

End Use (Baseline) Technologies

Figure F-1 End Use (Baseline) Technology Profiles for Electricity End Uses

			Efficiency	Life	Capital Cost	Installation Cost	O&M Cost
Level 3	Area	(kW)	(%)	(Years)	($)	($)	($)
Direct Process Heating	Direct Fired Heaters/Steam Boilers	586	65%	15	$25,000	$35,000	$10,000
Cooling and Refrigeration	Refrigeration Compressors	221	30%	15	$250,000	$80,000	$15,000
Drivers	Engines/ Gas Turbines	1,839	30%	15	$400,000	$140,000	$22,500
	Motors	147	93%	20	$15,000	$7,500	$1,000
Rotors	Air Compressors	37	95%	15	$50,000	$10,000	$2,500
	Pumps	74	70%	50	$ -	$ -	$5,000
	Fans/Blowers	22	65%	15	$65,000	$20,000	$2,500
	Gas Compressors	368	95%	20	$400,000	$350,000	$2,500

Figure F-2 End Use (Baseline) Technology Profiles for Natural Gas End Uses

			Efficiency	Life	Capital Cost	Installation Cost	O&M Cost
Level 3	Equipment / Process	(kW)	(%)	(Years)	($)	($)	($)
Direct Process Heating	Direct Fired Heaters/Steam Boilers	586	65%	15	$25,000	$35,000	$10,000
Cooling and Refrigeration	Refrigeration Compressors	221	30%	15	$250,000	$80,000	$15,000
Drivers	Engines/ Gas Turbines	1,839	30%	15	$400,000	$140,000	$22,500
	Motors	147	93%	20	$15,000	$7,500	$1,000
Rotors	Air Compressors	37	95%	15	$50,000	$10,000	$2,500
	Pumps	74	70%	50	$ -	$ -	$5,000
	Fans/Blowers	22	65%	15	$65,000	$20,000	$2,500
	Gas Compressors	368	95%	20	$400,000	$350,000	$2,500

Columns highlighted in yellow indicate that technology is not replace, only retrofitted.

Figure F-3 End Use (Baseline) Technology Profiles for Fuel Gas End Uses

		Rating	Efficiency	Life	Capital Cost	Installation Cost	O&M Cost
Area	Equipment / Process	(kW)	(%)	(Years)	($)	($)	($)
Direct Process Heating	Direct Fired Heaters/Steam Boilers	586	65%	15	$25,000	$35,000	$10,000
Cooling and Refrigeration	Refrigeration Compressors	221	30%	15	$250,000	$80,000	$15,000
Drivers	Engines/ Gas Turbines	1,839	30%	15	$400,000	$140,000	$22,500
	Motors	147	93%	20	$15,000	$7,500	$1,000
Rotors	Air Compressors	37	95%	15	$50,000	$10,000	$2,500
	Pumps	74	70%	30	$ -	$ -	$5,000
	Fans/Blowers	22	65%	15	$65,000	$20,000	$2,500
	Gas Compressors	368	95%	20	$400,000	$350,000	$2,500

Columns highlighted in yellow indicate that technology is not replace, only retrofitted.

Appendix G

Sequence of Measures for Cost Curves

Figure G-1: Cost Effectiveness Ranking - Natural Gas Producers

Measure Name	Unit Cost ($/GJ)
Gas Compressors - Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-69.356
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	-13.322
Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices	0.000
Air Compressors - Annual air leak detection and repair program	0.000
Air Compressors - Intake air temperature reduction	0.000
Pumps - Pump selection in lead/lag or primary/secondary	0.000
Gas Compressors - Set valve positions to run compressor at optimum efficiency and reduce bypass	0.000
Gas Compressors - Volume pocket adjustments - manual or automatic to match inlet gas stream	0.000
Gas Compressors - Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	0.000
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.023
Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency	0.044
Engines - Improvement of engine operation	0.046
Fans/ Blowers - Fan housing and air flow improvements and hub bells installed	0.063
Cooling - Optimized automated condenser control	0.130
Fans/ Blowers - Two speed motors or variable speed drives	0.161
Heating - Line heater operating practices (seasonal)	0.723
System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	0.820
Gas Turbines - Utilization of waste heat from exhaust	1.174
System - Power factor > 95%	1.230
Gas Compressors - Inlet and Interstage cooling	2.880
Heating - Use of energy efficient fired heaters (burners) with improved controls	4.566
Heating - Oil treater temperature control to avoid overheating and over treating	10.524
Heating - Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	24.319
Gas Compressors - Gathering Systems - Introduce site measurements to improve energy efficiency	56.445

Figure G-2: Cost Effectiveness Ranking - Natural Gas Processors (Sweet)

Measure Name	Unit Cost ($/GJ)
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	-55.557
Heating - Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	0.000
Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices	0.000
Air Compressors - Annual air leak detection and repair program	0.000
Air Compressors - Intake air temperature reduction	0.000
Pumps - Pump selection in lead/lag or primary/secondary	0.000
Gas Compressors - Set valve positions to run compressor at optimum efficiency and reduce bypass	0.000
Gas Compressors - Volume pocket adjustments - manual or automatic to match inlet gas stream	0.000
Engines - Improvement of engine operation	0.060
Cooling - Use sub-cooler to increase percent liquid entering chiller	0.062
Cooling - Improve insulation to ensure at least 90% of insulation in very good condition	0.069
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.097
Fans - Fan housing and air flow improvements and hub bells installed	0.148
Cooling - Optimized automated condenser control	0.158
Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency	0.182
System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	0.269
Fans - Two speed motors or variable speed drives	0.390
System - Power factor > 95%	0.404
Heating - Improved design practices and conversion from natural draft to forced air systems.	0.852
Gas Turbines - Utilization of waste heat from exhaust	1.518
Heating - Annual steam trap surveys and repair	1.893
Heating - Use of energy efficient fired heaters (burners) with improved controls	10.769
Gas Compressors - Inlet and Interstage cooling	11.997
Heating - Glycol Dehydrators - Control system in place to monitor inlet gas volumes and glycol circulation rate	57.360

Figure G-3: Cost Effectiveness Ranking - Natural Gas Processors (Sour)

Measure Name	Unit Cost ($/GJ)
Heating - Improved design practices and conversion from natural draft to forced air systems.	0.000
System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	0.021
System - Power factor > 95%	0.032
Engines - Improvement of engine operation	0.087
Gas Compressors - Volume pocket adjustments - manual or automatic to match inlet gas stream	0.140
Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices	0.176
Pumps - Pump selection in lead/lag or primary/secondary	0.257
Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency	0.350
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.479
Gas Compressors - Acid Gas Injection - Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.	0.559
Fans - Two speed motors or variable speed drives	0.934
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	1.041
System - Up-to-date DCS or PLC controls to optimize equipment run times and rates	1.295
Cooling - Optimized automated condenser control	1.470
Cooling - Improve insulation to ensure at least 90% of insulation in very good condition	1.643
Heating - Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	1.679
Heating - Boiler blowdown optimisation	1.857
Gas Turbines - Utilization of waste heat from exhaust	2.098
Gas Compressors - Inlet and Interstage cooling	2.098
Heating - Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	2.124
Fans - Fan housing and air flow improvements and hub bells installed	2.283
Air Compressors - Intake air temperature reduction	3.822
Air Compressors - Annual air leak detection and repair program	5.588
Cooling - Use sub-cooler to increase percent liquid entering chiller	6.712
Gas Compressors - Set valve positions to run compressor at optimum efficiency and reduce bypass	6.985
Heating - Annual steam trap surveys and repair	9.890

Figure G-4: Cost Effectiveness Ranking – Light and Medium Oil

Measure Name	Unit Cost ($/GJ)
Gas Compressors - Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-7.722
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	-2.172
Pump selection in lead/lag or primary/secondary	0.000
Pumps - Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	0.000
Gas Compressors - Set valve positions to run compressor at optimum efficiency and reduce bypass	0.000
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.003
Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency	0.008
Gas Turbines - Utilization of waste heat from exhaust	0.107
Gas Compressors - Inlet and Interstage cooling	0.421
Heating - Annual steam trap surveys and repair	0.578
Heating - Use of energy efficient fired heaters (burners) with improved controls	3.290
System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	3.726
System - Power factor > 95%	5.589
Heating - Oil treater temperature control to avoid over heating and over treating	7.584

Figure G-5: Cost Effectiveness Ranking – Conventional Heavy Oil

Measure Name	Unit Cost ($/GJ)
Gas Compressors - Gathering Systems - Improved gathering systems - optimum pipe diameter, flow, pressure	-0.458
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	-0.214
Heating - Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners	0.000
Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices	0.000
Engines - Oilfield Pumping - Perform routine testing and correction of abnormalities	0.000
Air Compressors - Annual air leak detection and repair program	0.000
Air Compressors - Intake air temperature reduction	0.000
Pumps - Pump selection in lead/lag or primary/secondary	0.000
Gas Compressors - Set valve positions to run compressor at optimum efficiency and reduce bypass	0.000
Gas Compressors - Gathering Systems - Perform pigging to remove wax build up from the pipe walls in oil gathering systems	0.000
Engines - Oilfield Pumping - Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing	0.000
Engines - Improvement of engine operation	0.000
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.000
Gas Compressors - Set cylinder clearance to a minimum to optimize compressor efficiency	0.001
Gas Turbines - Utilization of waste heat from exhaust	0.003
Gas Compressors - Inlet and Interstage cooling	0.034
Fans - Fan housing and air flow improvements and hub bells installed	0.047
Fans - Two speed motors or variable speed drives	0.127
Heating - Improved design practices and conversion from natural draft to forced air systems.	0.204
Heating - Boiler blowdown optimisation	0.408
Heating - Annual steam trap surveys and repair	0.454
Heating - Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers	2.333
Heating - Use of energy efficient fired heaters (burners) with improved controls	2.580
Heating - Line heater operating practices (seasonal)	2.825
System - Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance	6.708
Heating - Fractionation - Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins	9.074

Figure G-6: Cost Effectiveness Ranking – Bitumen

Measure Name	Unit Cost ($/GJ)
Heating - Improved design practices and conversion from natural draft to forced air systems.	0
Gas Compressors - Volume pocket adjustments - manual or automatic to match inlet gas stream	0.196
Pumps - Pump selection in lead/lag or primary/secondary	0.280
System- Up-to-date DCS or PLC controls to optimize equipment run times and rates	0.296
Gas Compressors - Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.	0.671
Fans/ Blowers - Two speed motors or variable speed drives	1.220
Engines/ Gas Turbines - Improved performance monitoring, optimization and servicing practices	1.439
Gas Compressors - Right sizing to minimize recycling of gas and match inlet gas volume	1.457
Gas Turbines - Utilization of waste heat from exhaust	2.284
Gas Compressors - Inlet and Interstage cooling	2.937
Fans/ Blowers - Fan housing and air flow improvements and hub bells installed	2.983
Heating - Annual steam trap surveys and repair	3.669
Air Compressors - Intake air temperature reduction	4.162
Air Compressors - Annual air leak detection and repair program	6.084
Heating - Desiccant Dehydrators - Timely replacement of desiccant dehydrators	8.478
Pumps - Desiccant Dehydrators - Timely replacement of desiccant dehydrators	37.726

Appendix H

Detailed List of Technical Best Practices

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.

End Use Level 1
Generic

End Use Level 2
Pumps

Technical Best Practices
Pumps selection in leading or primary/secondary set-ups

Size and Unit (e.g. HP, kW, BTU) of Base Technology
100 HP

Energy Source
Electricity 90%, Natural Gas or Fuel Gas 10%

Measure Savings (%)
10

Measure Life (years)
20

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
250

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of benefit, personnel skill and availability, existing operating practices of equal run times of rotating equipment.

Short Description
Maintenance personnel measure energy usage (electrical readings on motor drive, gas flow readings on engines) on both the primary and secondary and in some cases tertiary process equipment trains, record process conditions (pressure and flow readings) for each train, determine most efficiency train(lowest energy consumption per unit of product flow). Prioritize train (equipment) operations from highest to lowest efficiency.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Fans and Blowers

Technical Best Practices
Two speed motors or variable speed drives

Size and Unit (e.g. HP, kW, BTU) of Base Technology
30 HP

Energy Source
Electricity 90%, Natural Gas or Fuel Gas 10%

Measure Savings (%)
33

Measure Life (years)
15

Full Capital Cost ($)
3500

Full Installation Cost ($)
500

OandM Cost (Incremental to Base Technology) ($)
500

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of benefit, motor control center (MCC) space limitation

Short Description
Operations requiring variable air delivery, such as gas and process cooling, can benefit from premium control with ASD allowing air delivery to match process requirements. ASD save electricity and improve product quality by providing plant operators greater and finer control.

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Fans and Blowers

Technical Best Practices
Fan housing and air flow improvements + hub bells installed

Size and Unit (e.g. HP, kW, BTU) of Base Technology
30 HP

Energy Source
Electricity 90%, Natural Gas or Fuel Gas 10%

Measure Savings (%)
8

Measure Life (years)
20

Full Capital Cost ($)
1300

Full Installation Cost ($)
400

OandM Cost (Incremental to Base Technology) ($)
0

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of the benefit, personnel skill, not including process benefits in evaluations

Short Description
Inlet bells smooth airflow into fan housing and tip seals reduce clearance between fan tip and housing resulting in reduced air turbulence and increased fan blade effectiveness.

Reference
http://www.hudsonproducts.com/products/parts/index.html and multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Engines

Technical Best Practices
Improved performance monitoring, optimization and servicing practices

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
15

Measure Life (years)
15

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
10000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Limited personnel, inexperienced operating staff, limited benefits for small engines

Short Description
There would only be an increase in OandM costs, but no capital costs for this measure. The OandM is just an estimate.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and www.betamachinery.com

End Use Level 1
Generic

End Use Level 2
Engines

Technical Best Practices
Improvement of engine operation (e.g. lean burn in gas engine, fuel control)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1000 - 3000 HP

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
40

Measure Life (years)

Full Capital Cost ($)
112500

Full Installation Cost ($)
Included

OandM Cost (Incremental to Base Technology) ($)
0 (increased operating cost is offset by reduced maintenance cost)

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Age of the unit, Cost of retrofit or replacement, Downtime and lost production constraints.

Short Description
Upgrading engine controls to monitor and improve fuel to air ratios and ignition for more effective and efficient operation. Upgrading to lean burn low NOx engines to reduce fuel usage and emissions.

Reference
Natural Gas EPA, PRO Fact Sheet No. 111

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Optimization of the compression ratio; pressure / volume curve and internal valve operation to minimize valve losses.

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15% Natural Gas or Fuel Gas 85%

Measure Savings (%)
15

Measure Life (years)
20

Full Capital Cost ($)
500

Full Installation Cost ($)
200

OandM Cost (Incremental to Base Technology) ($)
2500

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of benefit, lack of personnel to perform assessment, existing compressor may not have available ports for monitoring

Short Description
Annually, perform computer assisted pressure/volume graphs of suction and compression cycles on compressor (third party) to evaluate suction and discharge valve operation and losses as part of preventative maintenance program and equipment evaluation prior to plant turnarounds. Need to install transducers in port on compressor and drive staff.

Reference
www.betamachinery.com

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Set valve positions to run compressor at optimum efficiency and reduce bypass (process suction pressure valve, bypass valve, backpressure control valve)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15% Natural Gas or Fuel Gas 85%

Measure Savings (%)
15

Measure Life (years)
20

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
1000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of the impact, inexperienced operating staff

Short Description
To match inlet gas stream variations, adjust valve setting (process suction pressure valve, bypass valve, backpressure control valve) around compressor to reduce bypass and loading on compressor drive.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and www.spartancontrols.com and REM Technology Inc.

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Right sizing to minimize recycling of gas and match inlet gas volume

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15% Natural Gas or Fuel Gas 85%

Measure Savings (%)
10

Measure Life (years)
10

Full Capital Cost ($)
0

Full Installation Cost ($)
25000

OandM Cost (Incremental to Base Technology) ($)
0

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Capital constraint, Downtime and lost production constraints

Short Description
"The initial sizing of a machine should be based on the anticipated process conditions, usually the largest demand estimated in the life of the application. If conditions change, such as decreasing reservoir pressure or flow, then the equipment is often oversized for the new conditions. A bypass valve should be closed during normal operation to avoid burning fuel to produce gas that is recycled to suction. A good design practice to avoid oversizing is to install more pieces of smaller equipment to facilitate the load management."

Reference
Fuel Gas Best Management Practices, Module 8 p. 6-7

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Volume pocket adjustments - manual or automatic to match inlet gas stream

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15% Natural Gas or Fuel Gas 85%

Measure Savings (%)
10

Measure Life (years)
20

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
500

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Availability of volume pockets, Variability of inlet gas stream, Inexperienced operating staff

Short Description
To match inlet gas stream variations, adjust volume pockets manually or where applicable automatically on compressor cylinders to fully utilize equipment and drive to its capacity rating and rod loading and avoid multiple partially loaded compressors.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and www.aciservicesinc.com

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Set cylinder clearance to a minimum to optimize compressor efficiency

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15%   Natural Gas or Fuel Gas 85%

Measure Savings (%)
10

Measure Life (years)
5

Full Capital Cost ($)
0

Full Installation Cost ($)
5000

OandM Cost (Incremental to Base Technology) ($)
0

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Loss of production (downtime), Downtime related to the assessment and adjustments

Short Description
"Cylinder clearance should be set at a minimum to have the compressor run at optimum efficiency. A compressor performance analysis using the manufacturer's performance software is required to determine the optimum clearance settings. It should be note that the minimum value for required processing conditions rather than simply the minimum clearance. Please consult with an expert before making cylinder clearance adjustments."

Reference
Fuel Gas Best Management Practices, Module 8 p. 8

End Use Level 1
Generic

End Use Level 2
Gas Compressors

Technical Best Practices
Inlet and Interstage cooling

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 HP

Energy Source
Electricity 15% Natural Gas 85%

Measure Savings (%)
20

Measure Life (years)
15

Full Capital Cost ($)
60000

Full Installation Cost ($)
60000

OandM Cost (Incremental to Base Technology) ($)
1000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Cost of equipment

Short Description
This can be a retrofit depending on temperature of inlet or interstage gas.

Reference
Optimum Energy Management Inc.`s `Reducing Operating Costs Through Energy Management`Workshop manual and GPSA Engineering Data Book at www.gasprocessors.org

End Use Level 1
Generic

End Use Level 2
Air Compressors

Technical Best Practices
Annual air leak detection and repair program

Size and Unit (e.g. HP, kW, BTU) of Base Technology
50 HP

Energy Source
Electricity 100%

Measure Savings (%)
20

Measure Life (years)
3

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
4000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Limited resources, Limited benefits on small compressors

Short Description
Using intrinsically safe ultrasonic detecting device, survey air distribution system for air leaks. Tighten, seal or replace connections and fittings. Implement OandM practice to turn off air devices when in use.

Reference
EPA Wiserules, OMAF food processing document and NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Air Compressors

Technical Best Practices
Intake air temperature reduction

Size and Unit (e.g. HP, kW, BTU) of Base Technology
50 HP

Energy Source
Electricity 100%

Measure Savings (%)
7.5

Measure Life (years)
3

Full Capital Cost ($)
2000

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)
250

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, small benefit.

Short Description
Using outdoor air (change to fit UOG processes), 1% savings/3 deg. C. Seasonal control is requested on the air intake temperature (manual adjustment).

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Gas turbines

Technical Best Practices
Improved performance monitoring, optimization and servicing practices

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
15

Measure Life (years)
15

Full Capital Cost ($)

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)
$10,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness for regular checks, inexperienced operating staff.

Short Description
There would only be an increase in OandM costs, but no capital costs for this measure. The OandM is just an estimate.

Reference
EPA Wiserules

End Use Level 1
Generic

End Use Level 2
Gas turbines

Technical Best Practices
Utilization of waste heat from exhaust (e.g. Waste heat recovery for use in other parts of the plant, heat transfer to heat transfer fluid, and transport around plant, augment heat by auxiliary firing where needed)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
3000 HP

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
6

Measure Life (years)
15

Full Capital Cost ($)
$180,000

Full Installation Cost ($)
$180,000

OandM Cost (Incremental to Base Technology) ($)
$5,500

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Cost for retrofit, Location of the turbine

Short Description
Recovered flue gas heat can be a good source of energy to preheat process streams. Waste heat can be captured from a clean waste stream that normally goes into the atmosphere or down the drain. Implementation of many potential opportunities is restricted due to factors such as the distance between the turbine and the process streams/boiler, the available heat and volume in the flue stack gas, the consistency of the heat generation and lowered flue gas temperature causing condensation in the flue stack. Implementation of the measure is not widely practiced, especially in small- and medium-sized facilities. Consequently, a significant potential remains.

Reference
Marbek/Stantec in-house data

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Improved design practices and conversion from natural draft to forced air systems.

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
17.5

Measure Life (years)

Full Capital Cost ($)

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of engineering firms' technical awareness.

Short Description
The majority of fired heaters used in the upstream oil and gas are natural draft 2-pass fire tube design having a constant diameter which terminates into a vertical stack. The associated efficiency range is 72 to 82% for maintained condition. Forced air system will increase the average efficiency of fired heaters.

Reference
Fuel Gas Best Management Practices, Module 6 p. 1

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Improved performance monitoring, optimization and servicing practices on more than 80% of the direct fired heaters, including seasonal adjustments of burners

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
17.5

Measure Life (years)
15

Full Capital Cost ($)

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)
$10,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness for regular checks

Short Description
The most significant elements of long-term operating efficiency are the application of best available technology, implementation of operating and maintenance systems and management commitment.

Reference
Fuel Gas Best Management Practices, Module 6 p. 2

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Increase/improve heat exchange to minimize steam use - install turbulators for turbulent flow through exchangers

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
7.5

Measure Life (years)

Full Capital Cost ($)

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of technical awareness towards the benefits of turbulent flow and clean transfer surfaces

Short Description
Turbulent flow through heat exchangers increases the efficiency and reduces fouling.

Reference
NATCO Group (2009) [WWW], Firetube Turbulator, Available at: http://www.natcogroup.com/PDFContent/Consulting-Research/TechnicalPapers/NATCO-Turbulator.pdf, [Accessed: 6th April 2009] and multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Line heater operating practices (seasonal)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1.5 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
20

Measure Life (years)
15

Full Capital Cost ($)
$0

Full Installation Cost ($)
$0

OandM Cost (Incremental to Base Technology) ($)
$1,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of the benefits, Lack of personnel and Inexperienced operating staff

Short Description
Line Heaters are used in the operation of many pipeline systems to prevent hydrate formation and reduce liquid viscosity. These units should be periodically checked (seasonally) and adjusted to ensure the process fluid is not being heated above the temperature levels required to prevent hydrates.

Reference
Fuel Gas Best Management Practices, Module 1 p. 11

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Boiler blowdown optimisation

Size and Unit (e.g. HP, kW, BTU) of Base Technology
20 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
4

Measure Life (years)
20

Full Capital Cost ($)
$10,000

Full Installation Cost ($)
$5,000

OandM Cost (Incremental to Base Technology) ($)
$1,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness for regular checks, Lack of skilled personnel to do the evaluation for small boilers

Short Description
Boiler water must be blown down periodically to prevent scale from forming on boiler tubes. This process can be wasteful if too much is lost to blowdown. Automatic blowdown controls measure and respond to boiler water conductivity and acidity to ensure that only the right amount of blowdown water is used. Although automatic blowdown control is becoming a standard practice for new boilers, a large percentage of existing boilers do not have automated control.

Reference

Marbek/Stantec in-house data and www.engineeringtoolbox.coméboiler-blowdown-d_908.html

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Installation of economizer

Size and Unit (e.g. HP, kW, BTU) of Base Technology
N/A

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
12.5

Measure Life (years)

Full Capital Cost ($)
$100,000

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Capital and installation costs, Space requirements, Loss of production due to downtime

Short Description
An economizer is a heat exchanger that is designed to use heat from hot boiler flue gases to preheat water. Economizers are often used on large utility steam boilers to preheat the feedwater using recovered stack heat. The same principle can be applied to smaller heating boilers where there is a nearby demand for hot water. These installations have become more economical as energy prices have risen and smaller, lighter and more durable economizers have been developed. A condensing economizer improves the effectiveness of reclaiming flue gas heat by cooling the flue gas below the dewpoint. The condensing economizer thus recovers both the sensible heat from the flue gas and the latent heat from the moisture that condenses. The condensate is highly corrosive and requires measures to ensure that it does not enter the boiler. New boilers generally include economizers, while a large percentage of existing boilers has the potential to be retrofitted with an economizer.

Reference
Stantec and www.energysolutionscenter.org/boilerburner/Eff_Improve

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Use of energy efficient fired heaters (burners) with improved controls

Size and Unit (e.g. HP, kW, BTU) of Base Technology
5 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
12.5

Measure Life (years)
20

Full Capital Cost ($)
$90,000

Full Installation Cost ($)
$15,000

OandM Cost (Incremental to Base Technology) ($)
$0

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Incremental cost, Loss of production due to downtime

Short Description
An efficient burner provides the proper air-to-fuel mixture throughout the full range of firing rates, without constant adjustment. Many burners with complex linkage designs do not hold their air-to-fuel settings over time. Often, they are adjusted to provide high excess air levels to compensate for inconsistencies in the burner performance. An alternative to complex linkage designs, modern burners are increasingly using servomotors with parallel positioning to independently control the quantities of fuel and air delivered to the burner head. Controls without linkage allow for easy tune-ups and minor adjustments, while eliminating hysteresis, or lack of retraceability, and provide accurate point-to-point control. These controls provide consistent performance and repeatability as the burner adjusts to different firing rates.

Reference
http://www.nrel.gov/docs/fy04osti/33470.pdf.

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Oil treater temperature control to avoid over heating and over treating

Size and Unit (e.g. HP, kW, BTU) of Base Technology
0.5 - 2 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
10

Measure Life (years)
15

Full Capital Cost ($)

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)
$1,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Inexperienced operating staff

Short Description
Avoid over firing of treater in order to reduce water content and exceed pipeline oil specifications by monitoring discharge oil and setting treater firetube gas firing temperature at lowest to meet specification. Fuel gas consumption and light hydrocarbon flashing will be reduced and oil API rating will be maintained thus increasing the value of the oil and reducing the viscosity.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting

End Use Level 1
Generic

End Use Level 2
Fired Heaters / Boilers

Technical Best Practices
Annual steam trap surveys and repair

Size and Unit (e.g. HP, kW, BTU) of Base Technology
Not specified

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
15

Measure Life (years)
3

Full Capital Cost ($)
$40,000

Full Installation Cost ($)
$6,000

OandM Cost (Incremental to Base Technology) ($)
$4,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of economic and fuel saving benefits

Short Description
Steam traps are important to the performance of both end-use equipment and the distribution system. Traps provide for condensate removal with little or no steam loss. If the traps do not function properly, excess steam will flow through the end-use device or the condensate will back up into it. Excess steam loss will lead to costly operation while condensate backup will promote poor performance and may lead to water hammer. Traps can also remove non-condensable gases that reduce heat exchanger effectiveness. Regular steam trap surveys are an important measure to identify faulty steam traps and steam leaks. Repairing the steam leaks and faulty steam traps will minimize steam losses and improve system efficiency.
Steam trap surveys and repair is generally one of the first energy-efficiency measures implemented by plants and the measure is implemented by a large segment of the Industrial sector.

Reference
Stantec and Spirax Sarco at www.spiraxsarco.com

End Use Level 1
Generic

End Use Level 2
Refrigeration

Technical Best Practices
Use sub-cooler (with proper OandM practices) to increase percent liquid entering chiller, thereby reducing refrigeration load

Size and Unit (e.g. HP, kW, BTU) of Base Technology
300 HP

Energy Source
Electricity 75% Natural Gas or Fuel Gas 25%

Measure Savings (%)
2

Measure Life (years)
20

Full Capital Cost ($)
50000

Full Installation Cost ($)
20000

OandM Cost (Incremental to Base Technology) ($)
2000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness of the benefits, Retrofit cost and associated downtime

Short Description
Sector has significant market penetration in this technology. Concept involves adding a second heat exchanger in series with the refrigeration condenser. Subcooling reduces the volume of flash gas generated across the TSX valve and ultimately, the load on the compressor. Gas volume reduction can be as high as 25%. This measure needs a larger size unit to be justifiable. Coolant used is NGL from inlet separator. No business case for water as coolant.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and Startec at www.startec.ca

End Use Level 1
Generic

End Use Level 2
Refrigeration

Technical Best Practices
Improve insulation to ensure at least 90% of insulation in very good condition

Size and Unit (e.g. HP, kW, BTU) of Base Technology
300 HP

Energy Source
Electricity 75% Natural Gas or Fuel Gas 25%

Measure Savings (%)
5

Measure Life (years)
10

Full Capital Cost ($)
$14,000

Full Installation Cost ($)

OandM Cost (Incremental to Base Technology) ($)

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Inexperienced operating staff

Short Description
Insulation on the refrigerant piping and other parts of the system reduces the absorption of heat by the refrigerant from any environment other than the refrigerated area.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and Startec at www.startec.ca

End Use Level 1
Generic

End Use Level 2
Condensors / coolers

Technical Best Practices
Optimized automated condenser control (incl. temperature monitoring and fan pitch adjustment).

Size and Unit (e.g. HP, kW, BTU) of Base Technology
100 HP

Energy Source
Electricity 100%

Measure Savings (%)
5

Measure Life (years)
20

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
5000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of regular maintenance

Short Description
Measure is relevant mainly in hot summer months when cooling limitations affect ability to cut deeper into the gas stream. As result, more C3+ slips into the sales gas and the sales gas compressor load is increased.

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec

End Use Level 1
Process Specific

End Use Level 2
Gathering Systems

Technical Best Practices
Improved gathering systems - optimum pipe diameter, flow, pressure

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1000 HP

Energy Source
Electricity 10%   Natural Gas or Fuel Gas 90%

Measure Savings (%)
6

Measure Life (years)
3

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
15000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Availability of personnel to perform the evaluation

Short Description
This is a non-capital measure and applies to mature gas field piping networks where production distribution has changed and the network pipeline hydraulics are not optimized. Measure is labour based only (could lead to some CAPEX) for engineering to re-analyze and recommend the optimum flow path to minimize pressure drop and compressor load.

Reference
QM4 Engineering Ltd. – Spatial Data Mining

End Use Level 1
Process Specific

End Use Level 2
Gathering Systems

Technical Best Practices
Perform pigging to remove wax build up from the pipe walls in oil gathering systems

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1000 HP

Energy Source
Electricity 10%   Natural Gas or Fuel Gas 90%

Measure Savings (%)
3

Measure Life (years)
1

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
3000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of proactive pigging requirement in the evaluation

Short Description
Measure assumes that pigging facilities (launch and receive) are existing. Measure involves labour and maintenance to perform timely pigging of pipeline to reduce wax build-up, pipe flow diameter, pressure drop, and ultimately, compressor load.

Reference
US Environmental Protection Agency (EPA) (2005), Efficient Pigging of Gathering Lines. US EPA, Washington

End Use Level 1
Process Specific

End Use Level 2
Gathering Systems

Technical Best Practices
Hydrate formation mitigation is evaluated based on cost and emissions - e.g. Methanol can de injected into pipelines as an alternative to using line heaters to inhibit hydrate formation.

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1 MMBTU/hr

Energy Source
Electricity 10%   Natural Gas or Fuel Gas 90%

Measure Savings (%)
100%

Measure Life (years)
20

Full Capital Cost ($)
$4,000

Full Installation Cost ($)
$2,000

OandM Cost (Incremental to Base Technology) ($)
$1,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of regular hydrate formation assessment and regular gas composition monitoring, Cost benefit analysis using methanol versus line heaters

Short Description
Methanol can be injected into the pipeline as an alternative to using line heaters to inhibit hydrate formation. The energy consumed is minimal compared to a line heater and depending on chemical use and recovery rates may be an economic alternative. It is important to understand the required injection rates (accounting for seasonal variability) when evaluating methanol injection. Methanol recovery should also be considered as a viable option to reduce the cost of methanol injection. Methanol is a liquid and as such may accumulate in low points throughout the gathering system causing additional pressure drops and requirements for pigging.

Reference
Fuel Gas Best Management Practices, Module 1 p. 11 Natural Gas Star - methanol Injection

End Use Level 1
Process Specific

End Use Level 2
Gathering Systems

Technical Best Practices
Introduce site measurements to improve energy efficiency (e.g. SCADA system)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1000 HP

Energy Source
Electricity 10% Natural Gas or Fuel Gas 90%

Measure Savings (%)
5%

Measure Life (years)
20

Full Capital Cost ($)
50000

Full Installation Cost ($)
50000

OandM Cost (Incremental to Base Technology) ($)
-5000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Cost, Perception of staff reduction

Short Description
Measure involves adding unit instruments connected to SCADA network to remotely monitor critical process parameters, which if not optimized, lead to increased energy consumption.

Reference
NRCan OEE Dollars to $ense Energy Monitoring and Tracking Workshop and multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting.

End Use Level 1
Process Specific

End Use Level 2
Glycol Dehydrators

Technical Best Practices
Control system in place to monitor inlet gas volumes and glycol circulation rate

Size and Unit (e.g. HP, kW, BTU) of Base Technology

Energy Source
Electricity 5%   Natural Gas or Fuel Gas 95%

Measure Savings (%)
20%

Measure Life (years)
1

Full Capital Cost ($)
$0

Full Installation Cost ($)
$0

OandM Cost (Incremental to Base Technology) ($)
$2,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Lack of regular gas composition monitoring

Short Description
Of all operating variables affecting dehydrator fuel gas use, the circulation rate has the greatest impact. Over-circulation results in more fuel gas use without significant reduction in gas moisture content. Dehydrator systems often re-circulate TEG at rates two or more times higher than necessary. The operator's goal should be to keep the circulation rate as low as possible, while still maintaining the needed water content specification in the treated gas. (Savings assume a TEG dehydrator using a gas operated pump)

Reference
Fuel Gas Best Management Practices, Module 9 p. 7, 21 http://www.methanetomarkets.org/m2m2009/documents/events_oilgas_20090129_day2_plauchu_1430_eng.pdf

End Use Level 1
Process Specific

End Use Level 2
Desiccant Dehydrators

Technical Best Practices
Timely replacement of desiccant dehydrators (replace glycol dehydrator with desiccant dehydrator)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
1 MMCFd

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
0.10%

Measure Life (years)
15

Full Capital Cost ($)
$15,000

Full Installation Cost ($)
$5,000

OandM Cost (Incremental to Base Technology) ($)
-$2,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of regular monitoring of desiccant quality, Lack of awareness of operating limitation of desiccant

Short Description
Desiccant dehydrator or mole sieves have wet gas passing through a drying bed of desiccant beads or tablets. The beads or tablets pull moisture from the gas. In mole sieves, monitor the temperature profile during regeneration phase to avoid over extending regen cycle, wasting fuel gas and damaging the desiccant. Replace glycol dehydrators with desiccant dehydrators having tablets that gradually dissolve in the process. As the unit is fully enclosed, gas emissions are reduced. Emissions occur only when the vessel is opened, such as when new desiccant tablets are added. Economic analyses demonstrate that replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to 1063 MCF per year in fuel gas, vented gas, and operation and maintenance (OandM) costs and reduce methane emissions by 444 thousand cubic feet (Mcf) per year.

Reference
Stantec and Robinson, D (2007) "Methane Savings from Dehydrators and Compressors", CETAC-West Conference 2007, Jan 15th – 17th, 2007.

End Use Level 1
Process Specific

End Use Level 2
Fractionation

Technical Best Practices
Fractionation unit evaluated and monitored to ensure good performance (Minimize reflux via proper control system and/or tuning)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
3000 kW

Energy Source
Electricity 5% Natural Gas or Fuel Gas 95%

Measure Savings (%)
5%

Measure Life (years)
1

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
10000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of time to perform the evaluation to adjust control system, Lack of instrumentation and monitoring in place

Short Description
Measure applies to amine contactors, dehydrators and glycol regen towers, and vacuum towers in heavy oil upgrading. Proper optimization leads to reduced thermal load.

Reference
Stantec and Pinch Technology

End Use Level 1
Process Specific

End Use Level 2
Fractionation

Technical Best Practices
Condenser settings are optimized: temperature is monitored, fan pitch is appropriate, condenser bundle is cleaned regularly, avoid practices that damage fins e.g. high pressure spray, etc

Size and Unit (e.g. HP, kW, BTU) of Base Technology
3000 kW

Energy Source
Electricity 5%   Natural Gas or Fuel Gas 95%

Measure Savings (%)
5

Measure Life (years)
1

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
10000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of regular monitoring of settings and conditions of condenser, Lack of awareness of the impact of condenser damage

Short Description
Measure applies during (2) hot summer months when the condenser is duty limited. Also applies to (3) cold winter months when condenser can lead to excessive sub cooling.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and Startec at www.startec.ca

End Use Level 1
Process Specific

End Use Level 2
Sulphur Recovery

Technical Best Practices
Optimize SRU performance (e.g. Optimum stack top temperature, integration with surrounding units)

Size and Unit (e.g. HP, kW, BTU) of Base Technology

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
20%

Measure Life (years)
10

Full Capital Cost ($)
25000

Full Installation Cost ($)
25000

OandM Cost (Incremental to Base Technology) ($)
0

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of time to perform the evaluation to adjust control system, Lack of awareness, Lack of instrumentation in place

Short Description
Sulphur recovery units (SRU) at sour gas plants need to be effectively and efficiently integrated with the sweetening plant, utilities and tail gas incineration to take advantage of the large amount of energy that is consumed and generated in sour gas plants. As inlet gas composition changes over time modification to the sweetening plant amine circulating and regen rates, SRU waste heat recovery and boilers, and tail gas stack temperatures are required. See reference document for more details.

Reference
http://www.capp.ca/GetDoc.aspx?DocId=137324

End Use Level 1
Process Specific

End Use Level 2
Tail Gas Incineration

Technical Best Practices
Determine optimum incinerator operating conditions and run Incinerator at these conditions to reduce incinerator temperature and oxygen levels to optimum levels.

Size and Unit (e.g. HP, kW, BTU) of Base Technology
2 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
5%

Measure Life (years)
Routine adjustment

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
10,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Lack of instrumentation in place

Short Description
Incinerators can require fuel gas and steam assist to achieve optimal destruction of combustible material. Constantly changing conditions can lead to sub-optimal combustion or consume more fuel gas and steam than needed. Cost is labour to routinely evaluate incinerator conditions.

Reference
Sulphur Experts at www.sulphurexperts.com

End Use Level 1
Process Specific

End Use Level 2
Tail Gas Incineration

Technical Best Practices
Use of high efficiency incinerators e.g. Questor incinerators

Size and Unit (e.g. HP, kW, BTU) of Base Technology
2 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
5

Measure Life (years)
10

Full Capital Cost ($)
300,000

Full Installation Cost ($)
300,000

OandM Cost (Incremental to Base Technology) ($)
30,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Installation scheduling (Downtime)

Short Description
Questor Incinerators are large units (stack heights in the range of 200 ft). They offer incremental combustion efficiency and reduced fuel assist to incumbent technology at many facilities.

Reference
Questor Technology Inc. (2009) [WWW], Economic and Effective Waste Gas Incineration, Available at: http://www.questortech.com/, [Accessed: 6th April 2009] and Sulphur Experts at www.sulphurexperts.com

End Use Level 1
Process Specific

End Use Level 2
Tail Gas Incineration

Technical Best Practices
Use of high efficiency vortex burners

Size and Unit (e.g. HP, kW, BTU) of Base Technology
2 MMBTU/hr

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
10

Measure Life (years)
5

Full Capital Cost ($)
90,000

Full Installation Cost ($)
15,000

OandM Cost (Incremental to Base Technology) ($)
20,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness, Installation scheduling (Downtime)

Short Description
The Vortex burner is a device in which the combustion air is fed tangentially into the burner, creating a spin (vortex) to mix it with the fuel as it is injected. Additional air is drawn into the flames contained within the combustion tube, resulting in improved combustion.

Reference
www.johnzink.com and Stantec

End Use Level 1
Process Specific

End Use Level 2
Acid Gas Injection

Technical Best Practices
Assess operational requirements to identify optimum conditions to operate at and minimize compressor duty.

Size and Unit (e.g. HP, kW, BTU) of Base Technology

Energy Source
Electricity 50% Natural Gas or Fuel Gas 50%

Measure Savings (%)
?

Measure Life (years)
Periodic adjustment

Full Capital Cost ($)
Technical consultant - $

Full Installation Cost ($)
Field Staff

OandM Cost (Incremental to Base Technology) ($)
-

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of knowledge for doing the evaluation

Short Description
Establishing operating parameters of temperature and pressure based on system characteristics is fundamental to the efficient operation of an acid gas injection system. Correct operating temperatures prevent the formation of hydrates, allow for the removal of water and ultimately reduce the fuel gas required. It is critical that accurate data for reservoir conditions and acid gas composition is used to determine the operating parameters. As gas compositions or reservoir conditions change, operating parameters must be adjusted. This will be based on computer simulations performed by technical resources.

Reference
Fuel Gas Best Management Practices, Module 17 p. 4-5 EPA Gas Removal Presentations

End Use Level 1
Process Specific

End Use Level 2
Oilfield Pumping - pumpjacks, PCP, ESP

Technical Best Practices
Perform periodic checks and adjustments to well pumping drive through weight balance, motoring loading and right sizing

Size and Unit (e.g. HP, kW, BTU) of Base Technology
20 HP

Energy Source
Electricity 80% Natural Gas or Fuel Gas 20%

Measure Savings (%)
25%

Measure Life (years)
2

Full Capital Cost ($)
$1,500

Full Installation Cost ($)
$500

OandM Cost (Incremental to Base Technology) ($)
$250

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness and personnel, Lack of communication between field operators and plant office

Short Description
Check loading and balance on pumping motor drive through electric measurement, adjust or add weights to balance pumpjack. Reconnect or replace motor based on measured electric loading on motors. Most pump motor drives are oversized and can be downsized to reduce demand and consumption of electricity at wellsites.

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting and US Department of Energy (2009) [WWW], Industrial Technologies Program: Case Study - The Challenge: Improving the Performance of Oil Well Pumping Units, Available at: http://www1.eere.energy.gov/industry/bestpractices/case_study_oil_well.html,

End Use Level 1
Process Specific

End Use Level 2
Oilfield Pumping - pumpjacks, PCP, ESP

Technical Best Practices
Perform routine testing and correction of abnormalities e.g. drive belt and rod string conditions, fluid levels in casing, pump off controllers, pump rod packing, pump position (bottoming), condition of electrical equipment (capacitors, breakers, ...)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
20 HP

Energy Source
Electricity 80% Natural Gas or Fuel Gas 20%

Measure Savings (%)
5%

Measure Life (years)
2

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
$250

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of awareness and personnel, Lack of communication between field operators and plant office

Short Description
Perform routine testing and correction of abnormalities e.g. drive belt and rod string conditions, fluid levels in casing, pump off controllers, pump rod packing, pump position (bottoming), condition of electrical equipment (capacitors, breakers, motor overloads and wiring and boxes).

Reference
Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting

End Use Level 1
Process Specific

End Use Level 2
Electrical systems

Technical Best Practices
Check power quality - level and type of harmonics, entrance voltage level and variation and phase imbalance

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 kW

Energy Source
Electricity 100%

Measure Savings (%)
5%

Measure Life (years)
2

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
$1,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of electrical technical awareness, Lack awareness of benefits

Short Description
By taking electric measurements on facility entrance voltage and current and correcting phase imbalance to less than 2%, and harmonic voltage distortion level below 5% will prevent degradation of efficiency on all motors at facility.

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting

End Use Level 1
Process Specific

End Use Level 2
Electrical systems

Technical Best Practices
Power factor > 95%

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 kW

Energy Source
Electricity 100%

Measure Savings (%)
5%

Measure Life (years)
1

Full Capital Cost ($)
0

Full Installation Cost ($)
0

OandM Cost (Incremental to Base Technology) ($)
$1,500

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of electrical technical awareness, Lack awareness of benefits

Short Description
Maintaining facility power factor above 95% through the installation of capacitors will reduce electricity demand and consumption charges.

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting

End Use Level 1
Process Specific

End Use Level 2
Controls

Technical Best Practices
Up-to-date DCS or PLC controls to optimize equipment run times and rates

Size and Unit (e.g. HP, kW, BTU) of Base Technology
500 kW

Energy Source
Electricity 40%   Natural Gas or fuel Gas 60%

Measure Savings (%)
5%

Measure Life (years)
20

Full Capital Cost ($)
200K

Full Installation Cost ($)
300K

OandM Cost (Incremental to Base Technology) ($)
10K

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of capital, Loss production due to downtime

Short Description
This measure may be partially covered under lines 34 and 37 above. Measure assumes that there is an existing DCS system but incremental improvements to the system will yield energy savings through optimal controls.

Reference
NRCan OEE Dollars to $ense Spot the Energy Savings Opportunities Workshop and Multiple energy audit reports of UOG facilities performed by Optimum Energy Management Inc. and Stantec Consulting

End Use Level 1
Process Specific

End Use Level 2
Electricity generation

Technical Best Practices
Microturbines with heat recovery (natural gas turbines)

Size and Unit (e.g. HP, kW, BTU) of Base Technology
150 kW

Energy Source
Natural Gas or Fuel Gas 100%

Measure Savings (%)
60%

Measure Life (years)
10

Full Capital Cost ($) / Full Installation Cost ($)
280,000

OandM Cost (Incremental to Base Technology) ($)
15,000

Barriers (Include everywhere: Remaining life of the facility - Capital Cost best practices) Lack of time to perform the evaluation to adjust control system, Lack of awareness
Lack of knowledge for appropriate application

Short Description
Microturbines represent a relatively new technology that has a considerable niche potential in the oil and gas industry. The turbine is basically a jet engine that produces shaft power, rather than thrust. They are small high-speed gas turbines that burn fuels such as natural gas and perhaps more importantly, flare gas to produce high quality electricity. Microturbines also feature cogeneration capabilities so that facilities can use the heat generated by a microturbine in a variety of ways such as the production of hot water, absorption cooling, dehumidification, etc., thus enabling facilities to be more cost and energy efficient. Electricity being generated differ the electricity purchased.

Reference
ARPEL (2003), On-Site Generation of Electricity. ARPEL, Uruguay

Prepared by: Stantec Consulting Ltd. in Association with Marbek Resource Consultants Ltd.