Mining Hot Water Production Challenge

Integration of Inproheat's Submerged Combustion Technology and Combustion & Energy Systems' ConDex System with an Oil Sands Mining Facility

Final Report

RECORD OF REVISION

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TABLE OF CONTENTS

LIST OF APPENDICES:

1.0 EXECUTIVE SUMMARY

Foresight, working with Alberta Innovates and COSIA's Greenhouse Gas (GHG) Environmental Priority Area (EPA) created the Mining Hot Water Production Challenge to find alternative water heating methods that can replace or supplement conventional mine hot water production, while materially reducing greenhouse gas (GHG) emissions.

At the completion of the Challenge phase, the technology evaluation was narrowed down to two potential technologies in order to perform a technical and economic evaluation. The following two technologies were selected for the heating of Oil Sands Process Water evaluations:

- Inproheat's Submerged Combustion (SubCom) Technology
- Combustion & Energy Systems' Condensing Economizer (ConDex) Technology

The main goal of the study is to evaluate the GHG emission reduction for SubCom (which provides direct heating by directly contacting the products of Natural Gas combustion from the combustion chamber with Process Water) and ConDex (which provides heating through the recovery of waste heat from the flue gas of a boiler or GTG/HRSG) for selected Oil Sands applications. During Phase 1 of the study, various scenarios were developed for each technology and the technology suppliers provided technical sizing data.

In order to evaluate the magnitude of the potential GHG (CO_2) emission reductions for the two technologies, a Microsoft Excel (with Winsteam Add-In) based Energy and Material Balance Model was developed for each of the cases evaluated. The model compares the GHG emissions generated in typical steam generation heating of Process Water and the alternative technologies.

After review of the Phase 1 Energy & Material Balances, COSIA narrowed down the evaluation cases to a single SubCom and a single ConDex case to carry forward to Phase 2 which consisted of a Class V Level Capital Cost (CapEx) Estimate, Operating Cost (OpEx) Estimate, Evaluation of NPV, Payback and IRR, Calculation of CO_2 Avoidance Costs and a Water Chemistry Modeling Exercise.

The Phase 2 cases are as follows:

- SubCom: Install two Units (total 300MMBtu/h – 317GJ/h)
- ConDex: Install unit in line with flue gas from a single Auxiliary Boiler (heating 300 m^3/h Process Water in Winter and 150 m^3/h Process Water in Summer).

As the technologies can both produce hot water, but in two dramatically different ways, there was not an attempt to directly compare SubCom and ConDex. Each technology was evaluated independently to determine the GHG savings against the traditional method of Hot Process Water generation (steam generation via Auxiliary Boilers or GTG / HRSGs and shell and tube steam condensers).

The base case for the Mining Hot Water Production Challenge economic evaluation was a brown field installation where a portion of the existing hot water heating equipment (Auxiliary Boiler duty and associated Boiler Feedwater Pump power) would be idled in order to materially reduce greenhouse gas (GHG) emissions. The economics are based on paying off the equipment costs with the delta in utility costs. The operating utility values (i.e. Natural Gas, power) are based on a delta between an Auxiliary Boiler and the new technology requirements. The base case OPEX does not include any financial values for carbon credits / taxes. Calculations have been included for NPV per tonne CO_2 abated and CAPEX per tonne CO_2 abated. An alternative case has been included with an assumed Carbon Levy.

Both Inproheat's Submerged Combustion (SubCom) Technology and Combustion & Energy Systems' Condensing Economizer (ConDex) Technology are technically viable alternatives to traditional Hot Process Water generation (steam generation via Auxiliary Boilers or GTG / HRSGs and shell and tube steam condensers). Both systems have been installed in industrial facilities and are currently advanced enough to be installed as a prospective pilot in an Oil Sands facility.

1.1 SUBCOM EVALUATION SUMMARY

The table below provides a summary of the Duty and Emissions Savings for the selected SubCom scenario:

Case	**Includes Process Water Pump**		**Excludes Process Water Pump**	
Duty Basis	**Auxiliary Boiler (1)**	**Auxiliary Boiler (1)**	**Auxiliary Boiler (1)**	**Auxiliary Boiler (1)**
Seasonal	**Winter**	**Summer**	**Winter**	**Summer**
Duty (GJ/hr)	311.9	300.1	311.9	300.1
Emissions Saving (tonCO_2e/dy) – Natural Gas	88	69	88	69
Emissions Saving (tonCO_2e/dy) – Power	-55	-55	-34	-34
Emissions Saving (tonCO_2e/dy) – Total	33	14	54	35

The following shows the Economic Modelling results:

SubCom Base Cases:

Case	Includes Process Water Pump		Excludes Process Water Pump	
	50:50 Winter / Summer	67:33 Winter / Summer	50:50 Winter / Summer	67:33 Winter / Summer
SubCom Budget Quote (1Q 2018 $CAD)	$11,305,319		$11,305,319	
Total Installed Cost (TIC) (1Q 2018 $CAD)	$27,337,000		$23,807,000	
NPV ($)***	$(34,204,308)	$(33,103,200)	$(18,388,161)	$(17,287,053)
IRR	N/A	N/A	(2.0)%	(1.0)%
Payback Period (years)	N/A	N/A	N/A	N/A
NPV***/Tonne CO_2 Abated	$(147.72)	$(125.15)	$(41.89)	$(36.63)
Capex/Tonne CO_2 Abated	$118.06	$103.35	$54.24	$50.45

***@8% Hurdle Rate

SubCom Alternative Case:

Case	Excludes Process Water Pump & Includes Assumed Carbon Levy	
	50:50 Winter / Summer	67:33 Winter / Summer
SubCom Budget Quote (1Q 2018 $CAD)	$11,305,319	
Total Installed Cost (TIC) (1Q 2018 $CAD)	$23,807,000	
NPV ($)***	$(9,261,808)	$(7,475,309)
IRR	4.0%	4.9%
Payback Period (years)	18.4	16.8
NPV***/Tonne CO2 Abated	$(21.10)	$(15.84)
Capex/Tonne CO2 Abated	$54.24	$50.45

***@8% Hurdle Rate

SubCom units provide an emissions savings compared to conventional steam generation methods of heating. This emissions savings is generated by the increase in thermal efficiency between steam generation and SubCom as Natural Gas is combusted in both technologies.

The potential duty production from a SubCom Unit is significant. Two units are able to provide similar to a typical Auxiliary Boiler duty. This would potentially allow a facility to utilize a SubCom unit(s) in lieu of Auxiliary Boilers during the expansion of a mine or in the construction of a new mine (for water heating purposes only).

With the NPV, IRR and Payback periods shown above, the SubCom technology on its own is financially challenged when evaluating the installation feasibility versus utility savings alone (considering the basis of idling existing steam generation equipment).

With the available duty of the SubCom units and its ability to replace the comparable duty of a boiler, there may be opportunity savings when installing a SubCom unit in lieu of a new Auxiliary Boiler (criteria has not been evaluated in this study).

In a green field or system capacity expansion application, Inproheat's SubCom technology is promising in that a similar order of magnitude total installed cost can provide an equivalent amount of heated Process Water while providing the benefit that the following systems would not need to be expanded:

- Demineralized Water Treating
- Condensate Polishing
- Blowdown System
- Process Water Exchangers

1.2 CONDEX EVALUATION SUMMARY

The table below provides a summary of the Duty and Emissions Savings for the selected ConDex scenario:

Duty Basis	**Auxiliary Boiler**	**Auxiliary Boiler**
Seasonal	**Winter**	**Summer**
Service	**Direct Heating**	**Direct Heating**
Duty (GJ/hr)	87.3	46.3
Emissions Saving (tonCO_2e/dy) – Natural Gas	133	69
Emissions Saving (tonCO_2e/dy) – Power	1	-1
Emissions Saving (tonCO_2e/dy) – Total	135	68

The following shows the Economic Modelling results:

ConDex Base Case:

Case	**50:50 Winter / Summer**	**67:33 Winter / Summer**
ConDex Budget Quote (1Q 2018 $CAD)	$1,769,340	
Total Installed Cost (TIC) (1Q 2018 $CAD)	$7,637,000	
NPV ($)* **	$25,409,135	$29,207,755
IRR	33.0%	36.5%
Payback Period (years)	3.2	2.9
NPV*/Tonne CO_2 Abated**	$25.50	$26.37
Capex/Tonne CO_2 Abated	$7.67	$6.90

***@8% Hurdle Rate

ConDex Alternative Case:

Case	Includes Assumed Carbon Levy	
	50:50 Winter / Summer	**67:33 Winter / Summer**
ConDex Budget Quote (1Q 2018 $CAD)	$1,769,340	
Total Installed Cost (TIC) (1Q 2018 $CAD)	$7,637,000	
NPV ($)***	$46,125,181	$52,235,050
IRR	49.5%	54.5%
Payback Period (years)	2.2	2.0
NPV***/Tonne CO2 Abated	$46.29	$47.16
Capex/Tonne CO2 Abated	$7.67	$6.90

***@8% Hurdle Rate

The ConDex technology provides a notable emissions savings by improving the operating efficiency of conventional steam generation methods of heating. The emissions reduction is possible as the ConDex unit provides all of its duty from the boiler or GTG/HRSG flue gas, thereby not creating any additional emissions (no additional Natural Gas firing is required).

With the NPV, IRR and Payback periods shown above, the ConDex technology has significant financial potential based on the economic model. This is supported by the high values for NPV/Tonne CO_2 Abated and low Capex/Tonne CO_2 Abated.

With the available duty of ConDex units and its ability to increase the steam production capacity of existing boilers and Cogen units, there may be an opportunity savings when installing a ConDex unit in lieu of a new Auxiliary Boiler.

2.0 STUDY BACKGROUND

Foresight, working with Alberta Innovates and COSIA's Greenhouse Gas (GHG) Environmental Priority Area (EPA) created the Mining Hot Water Production Challenge to find alternative water heating methods that can replace or supplement conventional mine hot water production, while materially reducing greenhouse gas (GHG) emissions. At the completion of the Challenge phase, the technology evaluation was narrowed down to two potential technologies in order to perform a technical and economic evaluation.

The following two technologies were selected for the heating of Oil Sands Process Water Evaluation:

- Inproheat's Submerged Combustion (SubCom) Technology
- Combustion & Energy Systems' Condensing Economizer (ConDex) Technology

The study considered the following opportunities to integrate the technologies into an Oil Sands mine facility:

- Evaluate SubCom technology for the purposes of heating recycled Oil Sands Process Water in an Oil Sands mine facility.
- Evaluate ConDex technology for the purposes of recovering waste heat and water from boiler flue gas for heating recycled Oil Sands Process Water in an Oil Sands mine facility.
- Evaluate ConDex technology for the purposes of recovering waste heat and water from gas turbine and heat recovery steam generator (cogeneration) flue gas for heating recycled Oil Sands Process Water in an Oil Sands mine facility.

3.0 STUDY OBJECTIVES

3.1 OVERALL STUDY OBJECTIVES

The objectives of the overall study are as follows:

- Evaluate the GHG emission reduction for SubCom and ConDex technologies for selected Oil Sands applications.
- Determine the cost of carbon avoidance for the SubCom and ConDex technologies for selected Oil Sands applications.
- Identify any technical gaps or environmental trade-offs associated with the SubCom and ConDex technologies that may require further study.

3.2 PHASE 1 OBJECTIVES

Numerous cases for each technology were considered during the first Phase of the study.

The objectives of Phase 1 of the study are as follows:

- Generate Energy & Material Balances for the cases evaluated
- Evaluate the GHG (CO_2) emission reduction for the cases evaluated
- Provide data to COSIA to allow the selection of one case for SubCom and one case for ConDex to carry forward to Phase 2.

3.3 PHASE 2 OBJECTIVES

Phase 2 further evaluated the single case for each technology.

The objectives of Phase 2 of the study are as follows:

- Generate Energy & Material Balances for the selected Phase 2 cases
- Evaluate the GHG (CO_2) emission reduction for the cases evaluated
- Process Water chemistry modelling exercise to determine any potential impact on the mine's existing Process Water system
- Generate Class V Level Capital Cost Estimate (CAPEX) for selected cases
- Estimate Operating Costs (OPEX) for selected cases
- Evaluation of NPV, Payback and IRR for selected cases based on CAPEX & OPEX
- Techno-Economic evaluation of SubCom and ConDex technologies for an oil sand mine application

4.0 SYSTEM DESCRIPTION

A typical Oil Sands Mine Facility uses heated Process Water in the extraction process. The tailings return (Reclaimed Water) is sent to the Recycle Water Pond, where it is pumped through an exchanger bank, first recovering heat from the Cooling Water return before being heated to 85-90°C in a Process Water/Low Pressure Steam condensing exchanger. The Hot Process Water is sent to the Ore Preparation Plant and Primary Extraction Plant for use in the extraction process and froth production.

The Utilities plant, where the Inproheat and Combustion & Energy Systems technologies are envisioned to be implemented, includes a COGEN area consisting of Gas Turbine/HRSG (GTG/HRSG) assembly, and / or Auxiliary Boilers producing 2100 kPag saturated steam. The steam is used for a variety of services, including letdown to 1050 kPag steam (LP Steam) for heating of the Hot Process Water and 2100 kPag export as column stripping steam and preheating to the Solvent Recovery Unit (SRU).

5.0 TECHNOLOGY SPECIFICATION

5.1 INPROHEAT'S SUBMERGED COMBUSTION

Inproheat's Submerged Combustion (SubCom) Technology is evaluated for the heating of Hot Process Water and Warm Process Water in a "typical" Oil Sands mine facility.

Inproheat's Submerged Combustion (SubCom) Technology includes a submerged combustion chamber with hot flue gas directly contacting the Reclaimed Process Water. The SubCom unit is equipped with:

- Tank
- Burners
- Submerged Combustion Chambers
- Heat Recovery Units
- Fuel Train
- Combustion Air Blowers
- Flue Gas Stack
- Process Control System

Depending on the overall site specific Process Water system configuration, external to the SubCom Unit, Hot Process Water Return Pumps may be required to return the heated water to the existing Process Water System (the SubCom Tank operates at close to atmospheric pressure). If the existing system has a very low pressure destination (pond or atmospheric storage tank), the Process Water Return Pumps may have a reduced head requirement or potentially eliminated.

The purpose of the installation is to use modularized SubCom units to replace, the steam generation from Boilers and HRSGs, utilizing the greater thermal efficiency (>90% higher heating value efficiency) seen in a SubCom unit.

5.1.1 EVALUATION SCENARIOS

5.1.1.1 Phase 1 Duty Basis

The following equipment equivalent duty cases are considered as part of Phase 1 of this study:

- Install one SubCom Unit
  (150 MMBtu/h = 158 GJ/h)
- Install four SubCom Units to Replace the Approximate Heating from two Auxiliary Boilers
- Install six SubCom Units to Replace the Approximate Heating from a single GTG / HRSG Cogen Unit

5.1.1.2 Phase 2 Duty Basis

At the conclusion of Phase 1, the following additional SubCom case was selected for CAPEX, OPEX and Techno-Economic Evaluations:

- Install two SubCom Units, approximately the heating duty from one Auxiliary Boiler
  (total 300MMBtu/h – 317GJ/h)

5.1.1.3 Seasonal / Service Basis

The following seasonal / service scenarios are considered as part of this study:

Season	Service	Water Inlet (°C)	Water Outlet (°C)
Winter	Process Water	2	85
Summer	Process Water	25	85

The flowrate of water is calculated based on the duty available. Refer to Appendix A, Case Schematics for a visual of the cases evaluated.

5.2 COMBUSTION & ENERGY SYSTEMS' CONDENSING ECONOMIZER TECHNOLOGY

Combustion & Energy Systems' Condensing Economizer (ConDex) Technology is evaluated to assess heat recovery in a "typical" Oil Sands mine facility by utilizing flue gas from Auxiliary Boilers and the GTG/HRSG (COGEN) assembly for the heating of Reclaimed Process Water via a customized heat exchanger assembly. The ConDex system recovers both sensible and latent heat energy.

Two different heating methods can be considered with the ConDex design. The "Direct" Heating Method passes Process Water (Reclaimed Water) through the ConDex tubes whereas the "Indirect" Heating Method passes Cooling Water through the ConDex tubes, which is subsequently passed through another exchanger bank to heat the Process Water.

Water condensed from the flue gases is collected in a basin and can be pumped back to Process. No additional fuel gas input is required for the ConDex system. The ConDex system comes equipped with:

- Condensing Economizer
- Holding Tank / Catchment Basin
- Flue Gas Blower / Fan
- Flue Gas Damper
- Flue Gas Stack
- Process Control System

External to the ConDex Unit, the following additional equipment is required to integrate the technology into the facility:

- Flue Gas Condensate Pumps (to return recovered water to Process Water)

5.2.1 EVALUATION SCENARIOS

5.2.1.1 Duty Basis

There are three major cases that will be used to evaluate the integration of ConDex technology into an Oil Sands mine:

- Install ConDex unit(s) inline with flue gas from one Auxiliary Boiler
- Install ConDex unit(s) inline with flue gas from two Auxiliary Boilers
- Install ConDex unit(s) inline with flue gas from one GTG/HRSG assembly

5.2.1.2 Phase 1 Seasonal Service Basis

Various seasonal / service scenarios are considered as part of this study. The table below identifies the cases that were considered for Combustion & Energy Systems (note in the Indirect Cases, Combustion & Energy Systems' designed their ConDex unit for Cooling Water, and outside the ConDex unit a separate Cooling Water / Process Water Exchanger is considered):

Phase	Season	Flue Gas Source	Heating Method	Fluid	Flow Rate (m^3/h)	Water Inlet (°C)	Water Outlet (°C)
1	Winter	One Aux Boiler	Direct	Process Water	CALC	2	85
1	Summer	One Aux Boiler	Direct	Process Water	CALC	25	85
1	Winter	One Aux Boiler	Indirect	Cooling Water	300	10	CALC
1				Process Water	CALC	2	CALC
1	Summer	One Aux Boiler	Indirect	Cooling Water	300	30	CALC
1				Process Water	CALC	25	CALC
1	Winter	Two Aux Boiler	Direct	Process Water	CALC	2	85
1	Summer	Two Aux Boiler	Direct	Process Water	CALC	25	85
1	Winter	Two Aux Boiler	Indirect	Cooling Water	600	10	CALC
1				Process Water	CALC	2	CALC
1	Summer	Two Aux Boiler	Indirect	Cooling Water	600	30	CALC
1				Process Water	CALC	25	CALC
1	Winter	One GTG/HRSG	Direct	Process Water	CALC	2	85
1	Summer	One GTG/HRSG	Direct	Process Water	CALC	25	85
1	Winter	One GTG/HRSG	Indirect	Cooling Water	800	10	CALC
1				Process Water	CALC	2	CALC
1	Summer	One GTG/HRSG	Indirect	Cooling Water	800	30	CALC
1				Process Water	CALC	25	CALC

CALC = Calculated by ConDex model or Fluor Energy and Material Balance based on available duty and ConDex exchanger area.

The ConDex exchangers are sized based on Winter and optimized to extract maximum duty from the flue gas and check rated against the summer conditions.

5.2.1.1 Phase 2 Seasonal Service Basis

At the conclusion of Phase 1, the following additional / modified ConDex case was selected for CAPEX, OPEX and Techno-Economic Evaluations:

Phase	Season	Flue Gas Source	Heating Method	Fluid	Flow Rate (m^3/h)	Water Inlet (°C)	Water Outlet (°C)
2*	Winter	One Aux Boiler	Direct	Process Water	300	2	By ConDex
2*	Summer	One Aux Boiler	Direct	Process Water	150	25	By ConDex

The ConDex exchangers are sized based on Winter and optimized to extract maximum duty from the flue gas and check rated against the summer conditions. The flowrates shown were selected for an assumed Process Water system. Parameters can be modified to optimize duty, flowrate or outlet water temperature. The lower Summer flowrate was selected as Process Water systems typically have an excess of low grade heat during the summer so an attempt was made to maximize outlet temperature.

*The Phase 2 cases use the same amount of flue gas under the same conditions as the Phase 1 one Auxiliary Boiler cases however the ConDex economizer is sized based on a fixed flow rather than a fixed outlet temperature.

Refer to Appendix A, Case Schematics for a visual of the cases evaluated.

6.0 PROCESS DATA

6.1 ATMOSPHERIC CONDITIONS

Parameter	Specification
Atmospheric Pressure	98 kPaa
Minimum Ambient Temperature	-45 °C
Maximum Ambient Temperature	36 °C
Winter Temperature for Burner Firing	-10 °C
Summer Temperature for Burner Firing	10 °C
Relative Humidity	60%
* Atmospheric Conditions provided by COSIA members.	

6.2 NATURAL GAS COMPOSITION

Components	Mole Fraction
H2O	0.0000
Helium	0.0000
Nitrogen	0.0050
CO2	0.0150
Methane	0.9775
Ethane	0.0015
Propane	0.0005
n-Butane	0.0002
i-Butane	0.0001
n-Pentane	0.0002
Total	1.0000
MW	16.58
LHV (GJ/kg)	0.04757
HHV (GJ/kg)	0.05271
* Natural Gas composition is an average of Natural Gas compositions expected in the Fort McMurray area	

6.3 PROCESS WATER QUALITY

Parameter	Unit	Influent Range
Acid extractable organics	mg/L	15-80
Alkalinity	mg/L as CaCO3	600-900
Ammonia	mg/L	0.0076-30
Arsenic	mg/L	0.0033-0.05
BOD5	mg/L	4-320
BTEX	mg/L	0.01-5
Cadmium	µg/L	0.00006-0.4
Chloride	mg/L	500-1000
Chromium	mg/L	0.0005-0.04
CODTotal	mg/L	175-650
Copper	mg/L	0.0001-0.03
DOC	mg/L	30-120
Hardness	mg/L as CaCO3	40-120
Lead	mg/L	0.0001-0.04
Mercury	µg/L	0.0005-0.2
Nickel	mg/L	0.005-0.04
O&G	mg/L	5-150
PAHs	mg/L	0.0004-0.015
pH		7.5-8.8
Phenols	mg/L	0.0036-0.0270
Selenium	mg/L	0.0009-0.156
Strontium	mg/L	0.31-0.8
TDS	mg/L	1200-3000
TOC	mg/L	40-250
TSS	mg/L	20-800
UVt	%	12
Vanadium	mg/L	0.001-0.05
Zinc	mg/L	0.02-0.35
* Process Water quality extracted from the Mining Hot Water Production Challenge: Request for Responses from Innovators.		

Refer to Section 9.0, Water Chemistry Evaluation for additional details on Process Water Quality.

6.4 COOLING WATER QUALITY

Cooling Water is considered to be "good" quality (treated water, mostly demineralized).

6.5 AUXILIARY BOILER FLUE GAS

Flue gas conditions for a typical Natural Gas fired Auxiliary Boiler are provided below:

Parameter	Units	Value
Flue Gas Flow Rate	t/h	245
Stack Exit Temperature	°C	160
Stack Exhaust Gas O2 mol%	%	2.1
Stack Exhaust Gas CO2 mol%	%	8.7
Stack Exhaust Gas H2O mol%	%	17.1
Stack Exhaust Gas N2 mol%	%	72.1

6.6 COGENERATION FLUE GAS

Flue gas conditions for a typical Natural Gas fired 85 MW ISO 7EA frame GTG, with duct burners at full firing are provided below:

Parameter	Units	Winter	Summer
Ambient Temperature	°C	-10	10
Ambient Relative Humidity	%	60	60
GTG Power	MW	98	87
GTG Load	%	100	100
Steam from HRSG Assembly	t/h	445	411
Flue Gas Flow Rate	t/h	1,204	1,111
Stack Exit Temperature	°C	110	110
Stack Exhaust Gas O2 mol%	%	10.7	10.8
Stack Exhaust Gas CO2 mol%	%	4.7	4.6
Stack Exhaust Gas H2O mol%	%	9.4	9.7
Stack Exhaust Gas N2 mol%	%	75.2	74.9

7.0 ENERGY MODELLING BASIS

7.1 METHODOLOGY

To assess both the Inproheat (SubCom) and Combustion & Energy Systems (ConDex) technologies, a process model is built in Microsoft Excel (with Winsteam Add-In) to give a direct comparison between the emissions impact of producing steam from the steam generation equipment versus the alternative technologies. Refer to Appendix B, Energy & Material Balances.

The model methodology is as follows:

- The technology supplier (Inproheat and Combustion & Energy Systems) supplied the technical data for the cases considered
- Based on the technology supplier Process Water temperatures and the outlet Process Water flowrate, the equivalent PW/LPS heat exchanger duty is calculated.
- From the exchanger duty, the required LP Steam flowrate is calculated.
- With the addition of LP steam losses, the total steam requirements from the boiler is calculated. The steam generation duty is calculated based on the BFW created by mixing returned condensate and make-up water and the MP Steam demand.

7.2 EQUIPMENT SPECIFICATIONS

7.2.1 AUXILIARY BOILERS

The Auxiliary Boilers are specified using provided information by COSIA. Boiler flue gas conditions for use in the ConDex cases are calculated from an existing installation and duty specifications surrounding the flue gas are provided in Section 6.0. The Auxiliary Boiler is modelled as producing 2100 kPag saturated steam.

7.2.2 GAS TURBINE/HRSG

Gas Turbines were modelled as a GE 7EA Frame turbine under ambient air conditions and gas composition shown in Section 6.0. HRSG assembly was modelled as a typical unit producing 2100 kPag saturated steam, with economizer and evaporator. Exhaust conditions at economizer outlet are reported in Section 6.0. Duct burners were modelled at full duct firing. Feedwater temperature was assumed to be 105°C based on a low pressure deaerator.

7.2.3 EXCHANGERS

The exchanger bank consists of numerous exchanger types in series that heat Reclaimed Water from 2-25°C to 85-90°C, depending on seasonal conditions. In the provided “typical” Oil Sands mine, the first exchanger heats the Reclaimed Water by exchanging with the warm Cooling Water return from the extraction process, in turn cooling the Cooling Water for re-use in the extraction process. The subsequent exchangers subcool the condensate for feed to the deaerator and condense steam using 1050 kPag steam to heat the Reclaimed Water to the final 85-90°C.

7.3 MAJOR ASSUMPTIONS

7.3.1 STEAM GENERATION

- Auxiliary Boiler efficiency is assumed as 91.5% (LHV) based on operational experience by COSIA members.
- GTG / HRSG efficiency is assumed as 85.0% (LHV) based on operational experience by COSIA members.
- Natural Gas higher heating value (HHV), is assumed to be 1.11 times the lower heating valve (LHV). Efficiencies are scaled between HHV and LHV on the same ratio.
- For model simplification and direct comparison purposes, duty provided by Cooling Water / Process Water exchangers is excluded. The duty is assumed to be 100% provided by steam. This is a fair assumption as this allows the duty from the alternative technologies to be directly compared to steam generation.
- To account for losses in the steam / condensate system, a “LP Steam Losses” stream is added to the model. A makeup water stream is added at the reclaimed water inlet temperature to account for the steam losses.
- Phase 1 Energy & Material Balances did not consider power consumed or produced from the boiler or GTG/HRSG.
- Phase 2 Energy & Material Balances considered the equivalent Auxiliary Boiler Forced Draft Fan and Boiler Feedwater Pumps power demand in the OPEX calculations.

7.3.2 INPROHEAT - SUBCOM

- Heat and Material Balances provided from Inproheat is based on one burner. Data for each case was factored up to the number of burners in operation based on the performance of a single burner.
- Supplied efficiencies are based on a higher heating value.

7.3.3 COMBUSTION & ENERGY SYSTEMS – CONDEX

- For indirect heating cases, all of the duty captured from the flue gas is transferred to the Process Water via the Cooling Water.
- The Cooling Water / Process Water heat exchanger area is not evaluated in the model and the outlet process temperature is assumed.
- The impact of the heated Process Water on the mine's hot Process Water system is not evaluated (i.e. lower Process Water Temperatures).

7.3.4 GREENHOUSE GAS EMISSIONS

Greenhouse Gas Emissions have been accounted for from two different sources:

- Natural Gas consumption from the technologies, Auxiliary Boiler(s) and GTG/HRSG
- Grid Electricity due to power consumption from the technologies and Auxiliary Boiler(s) (only considered in Phase 2 cases)

Refer to the Inputs Page in Appendix B, Energy & Material Balances for detailed data used in the model generation.

7.3.4.1 Natural Gas

Greenhouse Gas Emissions from Natural Gas consumption for SubCom, Auxiliary Boiler(s) and GTG/HRSG were determined based on the stoichiometry of the combustion of Natural Gas such that one mole of natural gas produces one mole of carbon dioxide. All other greenhouse gases are assumed negligible and not accounted for in the model.

GHG savings for SubCom is the difference in efficiency between the installed unit and the equivalent duty Auxiliary Boilers or GTG/HRSG.

As the ConDex unit does not require any additional Natural Gas usage, the GHG savings for ConDex is the emissions from an equivalent duty of steam generation (the ConDex technology uses flue gas from the Auxiliary Boiler(s) or GTG/HRSG, therefore no additional Natural Gas firing is required).

7.3.4.2 Grid Electricity

Power Consumption for the SubCom and ConDex technologies are based on the duties provided in each budgetary quote along with the estimated pump motor power.

Auxiliary Boiler power consumption is prorated based on produced steam (values estimated based on a “typical” Auxiliary Boiler).

The Power Consumed is converted into Greenhouse Gas Emissions based on an estimated Alberta grid emissions CO_2 intensity provided by COSIA (0.64 tonne CO_2/MWhr).

8.0 ENERGY MODELLING RESULTS

The results of the Phase 2 cases are provided in the following tables and graphs. The results provide equivalent comparisons between the alternative technology and steam generation. The results illustrate the net GHG (CO_2) savings due to implementation of the technologies.

As the technologies can both produce hot water, but in two dramatically different ways, there was not an attempt to directly compare SubCom and ConDex. Each technology was evaluated independently to determine the GHG savings against the traditional method of Hot Process Water generation (steam generation via Auxiliary Boilers or GTG / HRSGs and shell and tube steam condensers).

Refer to Appendix B, Energy & Material Balances.

8.1 SUBCOM RESULTS

Case	Includes Process Water Pump		Excludes Process Water Pump	
Phase	2	2	2	2
Duty Basis	Auxiliary Boiler (1)	Auxiliary Boiler (1)	Auxiliary Boiler (1)	Auxiliary Boiler (1)
Seasonal	Winter	Summer	Winter	Summer
Service	HPW	HPW	HPW	HPW
Number of SubCom Units	2	2	2	2
Duty (GJ/hr)	311.9	300.1	311.9	300.1
Efficiency (HHV)	98.55%	94.81%	98.55%	94.81%
Process Water In Flow (ton/hr)	889	1,190	889	1,190
Process Water In Temp. (ºC)	2	25	2	25
Process Water Out Flow (ton/hr)	901	1,198	901	1,198
Process Water Out Temp. (ºC)	85	85	85	85
Water Recovered (ton/hr)	11.6	7.9	11.6	7.9
Water Remaining in Flue Gas Exhaust (mole%)	2.0	6.7	2.0	6.7
Flue Gas Exhaust Temperature (°C)	18	38	18	38
SubCom NG Flow (kg/hr)	5,976	5,976	5,976	5,976
SubCom Blower Power (kW)	3,308	3,308	3,308	3,308
Process Water Pump Power (kW)	1,370	1,370	-----	-----
SubCom System Total Power (kW)	4,678	4,678	3,308	3,308
Auxiliary Boiler NG Flow (kg/hr)	7,353	7,060	7,353	7,060
Auxiliary Boiler Blower Power (kW)	922	886	922	886
BFW Pump Power (kW)	198	190	198	190
Auxiliary Boiler System Total Power (kW)	1,120	1,076	1,120	1,076
Emissions Saving (tonCO_2e/dy) – Natural Gas	88	69	88	69
Emissions Saving (tonCO_2e/dy) – Power	-55	-55	-34	-34
Emissions Saving (tonCO_2e/dy) – Total	33	14	54	35

8.2 CONDEX RESULTS

Phase	2	2
Duty Basis	Auxiliary Boiler	Auxiliary Boiler
Seasonal	Winter	Summer
Service	Direct Heating	Direct Heating
Duty (GJ/hr)	87.3	46.3
Process Water In Flow (ton/hr)	300	150
Process Water In Temp. (ºC)	2	25
Process Water Out Flow (ton/hr)	323	158
Process Water Out Temp. (ºC)	68	95
Water Recovered (ton/hr)	23.0	7.6
Water Remaining in Flue Gas Exhaust (kg/hr)	4,884	20,256
Flue Gas Exhaust Temperature (°C)	27	51
ConDex NG Flow (kg/hr)	-----	-----
ConDex Blower Power (kW)	224	224
Flue Gas Condensate Pump Power (kW)	11	11
ConDex System Total Power (kW)	235	235
Auxiliary Boiler NG Flow (kg/hr)	2,092	1,081
Auxiliary Boiler Blower Power (kW)	262	136
BFW Pump Power (kW)	56	29
Auxiliary Boiler System Total Power (kW)	318	165
Emissions Saving (tonCO_2e/dy) – Natural Gas	133	69
Emissions Saving (tonCO_2e/dy) – Power	1	-1
Emissions Saving (tonCO_2e/dy) – Total	135	68

9.0 WATER CHEMISTRY EVALUATION

Based on the Process Water composition in Section 6.0 provided by COSIA, a water chemistry modelling exercise has been performed for each of the Phase 2 cases. The recovered water composition provided by Inproheat or Combustion & Energy Systems in their respective bids (refer to Appendix C.3 and D.3 for water compositions) are analyzed on their own and blended with the mine's Process Water (assumed to be 8,000 ton/hr) to identify composition deviations for existing systems and provide mitigations as required.

Associated water balances are presented in Appendix E, Water Chemistry Model as well as stream data as interpreted from provided information.

9.1 COSIA PROCESS WATER

The COSIA Process Water can be characterized as a moderate pH water with low to moderate hardness, high alkalinity, high chlorides, and elevated residual oil and organics. Changes in scaling, corrosion, or compatibility with chemical programs are the primary concerns of this water chemistry evaluation. System pH will be the major determinant of all three of these changes and will be the focus of this analysis.

Blending process water with water from either of the technologies is anticipated to add dissolved carbon dioxide/carbonic acid to the systems, lowering system pH. To assess a worst case scenario for this effect, a water composition was created that falls within the range of COSIA Water Compositions but with pH and alkalinity on the low end of the provided ranges.

In the provided experimental data the SubCom heated water saw a minor pH increase with a comparably small reduction of bicarbonate. Although the results contradict the mechanism described above, they are consistent with the idea that carbon dioxide will be less soluble at elevated temperature and that aqueous sodium bicarbonate will thermally decompose into carbon dioxide and degas out of the water. This suggests it is prudent to create a high pH, low alkalinity process water composition along with the low pH case stated above.

The reported water hardness is predominantly calcium and magnesium based on provided test data. Magnesium is not a concern as the pH is too low to create magnesium hydroxide; the cause of scaling from magnesium. Calcium carbonate is a more probable concern for scaling that becomes more prevalent as bicarbonate converts to carbonate as pH increases above 8.3. Other multivalent cations are present, however the concentrations are sufficiently low that they are not deemed a scaling risk.

The alkalinity is present as bicarbonate with <5%wt carbonate at the high end of the pH range. Ammonia is present in not insignificant concentrations, however relative to the bicarbonate concentration it is not expected to have a significant effect on pH buffering. Silica is not reported and is considered negligible from a buffering standpoint. The buffering effect of organic species is also not considered due to limited speciation and an assumption that pH response is likely outside of the pH ranges considered in this evaluation.

9.2 SUBCOM

The data for the heated water from the SubCom Unit trial was provided for Foresight / COSIA by the Saskatchewan Research Council (SRC). The SRC pilot tested Inproheat's 250,000 BTU per hour test unit which can heat 10 to 50 litre per minute of water. Refer to SRC Publication No. 14244-1C18, Inproheat SubCom Pilot Testing for additional details.

Two runs (Trials 7 and 10) were performed at outlet temperatures of 80°C (Refer to Appendix C.3, Budgetary Quote for water composition details). The water passed through the unit experienced a modest pH increase and a reduction in bicarbonate concentration. This result is understood to be the result of a number of mechanisms that can affect the carbonic acid/bicarbonate/carbonate equilibrium of the system. These mechanisms include:

1. Solubility of carbon dioxide in water at coincident temperature and pH and atmospheric pressure resulting in absorption of carbon dioxide from the exhaust gas into the water, reducing pH or offgassing of carbon dioxide to , increasing pH.
2. Thermal decomposition of aqueous sodium bicarbonate into carbon dioxide and sodium hydroxide, increasing pH if the carbon dioxide gas leaves the evolved gas phase (bubbles) are disengaged from the liquid prior to reabsorption.
3. Scale formation, namely calcium carbonate, removes carbonate from the aqueous phase, shifting bicarbonate to carbonate and reducing pH.
4. Stripping of other volatile weak acids such as hydrogen sulphide, which would increase pH.
5. Stripping of volatile weak bases such as ammonia, which would reduce pH.
6. Dilution of process water with water condensed from burner exhaust, normalizing pH.

Based on the trial results, it would appear that a combination of Mechanisms #1 and #2 dominates as no other weak acids were documented in the trial compositions or COSIA specified typical water compositions to drive Mechanism

#4. Mechanism #6 will have a contributing effect, but is limited by the relative rates. This suggests that the SubCom system has a minor effect on water composition for the heated stream and once blended with additional process water there is no practical effect on pH.

To further evaluate this potential conclusion, two low alkalinity recycle water compositions were created at the high and low ends of the pH range for COSIA recycle water. These compositions were reconciled from an ionic basis to a molecular basis using OLI Analyzer 9.1.5 and the SubCom process unit was modelled in Aspen HYSYS 8.8 using the OLI 9.2 Engine. Modelling the low pH water produced a similar reduction in bicarbonate concentration and an increase in pH. The high pH water saw a reduction in pH to approximately that of the low pH effluent and a corresponding increase in bicarbonate concentration. This result suggests a normalizing effect on the heated pH of the heated water, making it less likely for the water to deviate from established pH regimes for Process Water. This suggests that chemical adjustment for this water is not required.

It should be noted that the simulation results are at a theoretical thermodynamic equilibrium that is not limited by reaction kinetics or system geometry.

Despite these difference in pH between simulated and measured compositions, once the effluent was blended with additional process water to meet typical usage, there was minor pH change, an increase for low pH water and a decrease for high pH waters.

The pH of the Process Water from the water balances is summarized below:

Case	SRC Trial 7-1	SRC Trial 10-1	Low pH Process Water	High pH Process Water
pH of Process Water at SubCom Inlet	8.11	7.91	7.50	8.73
pH of Process Water at SubCom Outlet	8.10	8.16	7.86	7.87
pH of Combined Process Waters	8.11	7.94	7.54	8.62

*Values presented are normalized to 25°C

**Trial values included have been reconciled in OLI and account for CO3 removed due to calcium carbonate formation

The results for the pH for the SRC trials are given in the table below:

Case	SRC Trial 7-1	SRC Trial 10-1
pH of Process Water at SubCom Inlet	8.2	7.97
pH of Process Water at SubCom Outlet	8.22 (1) 8.23 (2) 8.32 (3)	8.28 8.25 8.29

9.3 CONDEX

The composition of condensation collected from the ConDex unit was provided for a field test and two laboratory tests. Refer to Appendix D.3, Budgetary Quote for water composition details. The waters are consistently low on dissolved solids and contain residual metals. Residual nitrates suggest the adsorption of nitrogen oxides compounds from the combustion process, which would act as acids when reacted with water. Per the field test, the water should be low alkalinity with carbonic acid being the dominant species and a pH of 4.6. The lab test data had pHs of 6.3 and 5.5. Performed at comparable atmospheric conditions with similar fuel, trials should produce similar pH values. The condensation of a methane combustion exhaust stream was simulated in HYSYS 8.8 running the OLI 9.2 Engine as a point of comparison. The water had a pH of 4.35 at 25°C, suggesting that the field test is a more representative sample of in situ process conditions.

The simulated condensation was blended with the theoretical low pH, low alkalinity water. Once blended with the process water heated by the condensate, the combined stream had a pH of 7.4. Additional mixing with anticipated recycle water demand returns the combined stream to a pH of 7.5 at 25°C. Given low alkalinity of the condensation, this simulated outcome agrees with water principles and suggests that chemical adjustment for this water is not required.

The pH of the Process Water from the water balances is summarized below:

Case	Low pH Winter Process Water	Low pH Summer Process Water
pH of Process Water at ConDex Inlet	7.50	7.50
pH of Condensed Water from ConDex	4.35	4.52
pH of Total Water (Process & Condensed) from ConDex	7.39	7.46
pH of Combined Process Waters	7.5	7.5

*Values presented are normalized to 25°C

10.0 ECONOMIC EVALUATION

An economic evaluation was conducted on the Phase 2 SubCom and ConDex cases. The economic evaluation consisted of the following:

- Class V Capital Cost Estimate (-50% / +100%)
- Operating Cost Estimate
- Determination of Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period

10.1 DESIGN INPUTS AND OPEX ASSUMPTIONS

- Economic metrics, and utility costs are provided by COSIA.
- The facility is assumed to operate 7,884 hours / year.
- Economic model calculations are based on a 30 year operation with all capital costs occurring in year 1.
- Technology spare parts lists have been provided by Inproheat and Combustion & Energy Systems however they have not been included in the economic modelling.
- The base case for the Mining Hot Water Production Challenge economic evaluation was a brown field installation where a portion of the existing hot water heating equipment (Auxiliary Boiler duty and associated Boiler Feedwater Pump power) would be idled in order to materially reduce greenhouse gas (GHG) emissions. The economics are based on paying off the equipment costs with the delta in utility costs.
- The utility values (i.e. Natural Gas, power) are based on the utility requirements for the alternative technology and the utility avoidance by idling the Auxiliary Boiler.
- The base case OPEX does not include any financial values for carbon credits / taxes. Calculations have been included for NPV per tonne CO_2 Abated and CAPEX per tonne CO_2 Abated. An alternative case has been included with an assumed Carbon Levy.
- OPEX values are calculated for both 50:50 Winter / Summer and 67:33 Winter / Summer operating scenarios.

- Economic modelling considered that the duties produced by the alternative technologies was required 100% of plant operations. The model did not account for any periods where excess waste heat may be available.

Refer to Appendix F, Capital Cost and Appendix G, Economic Model for additional assumptions.

10.2 SUBCOM ECONOMIC EVALUATION

10.2.1 CAPITAL COST ESTIMATE

Case	**Includes Process Water Pump**	**Excludes Process Water Pump**
Item	**1Q2018 CAD$**	**1Q2018 CAD$**
SubCom Budget Quote	$11,305,319	$11,305,319
Total Equipment (incl Budget Quote above)	$12,610,000	$11,305,319
Direct Field Cost (DFC)	$15,983,000	$14,117,000
Bare Indicated Total Cost (BITC)	$21,870,000	$19,046,000
Contingency	$5,467,000	$4,761,000
Total Installed Cost (TIC)	**$27,337,000**	**$23,807,000**

Refer to Appendix F, Capital Cost for additional details

“Excludes Process Water Pump” Case was backed out from the “Includes Process Water Pump” cost by excluding the pump and associated installation costs.

10.2.2 NET PRESENT VALUE (NPV), INTERNAL RATE OF RETURN (IRR), AND PAYBACK PERIOD

SubCom Base Cases:

Case	**Includes Process Water Pump**		**Excludes Process Water Pump**	
	50:50 Winter / Summer	**67:33 Winter / Summer**	**50:50 Winter / Summer**	**67:33 Winter / Summer**
NPV ($)***	$(34,204,308)	$(33,103,200)	$(18,388,161)	$(17,287,053)
IRR	N/A	N/A	(2.0)%	(1.0)%
Payback Period (years)	N/A	N/A	N/A	N/A
NPV***/Tonne CO_2 Abated	$(147.72)	$(125.15)	$(41.89)	$(36.63)
Capex/Tonne CO_2 Abated	$118.06	$103.35	$54.24	$50.45

***@8% Hurdle Rate

SubCom Alternative Case:

Case	Excludes Process Water Pump & Includes Assumed Carbon Levy	
	50:50 Winter / Summer	**67:33 Winter / Summer**
NPV ($)***	$(9,261,808)	$(7,475,309)
IRR	4.0%	4.9%
Payback Period (years)	18.4	16.8
NPV***/Tonne CO2 Abated	$(21.10)	$(15.84)
Capex/Tonne CO2 Abated	$54.24	$50.45

***@8% Hurdle Rate

Refer to Appendix G, Economic Model for additional details.

10.3 CONDEX ECONOMIC EVALUATION

10.3.1 CAPITAL COST ESTIMATE

Item	**1Q2018 CAD$**
ConDex Budget Quote	$1,769,340
Total Equipment (incl Budget Quote above)	$1,854,000
Direct Field Cost (DFC)	$3,828,000
Bare Indicated Total Cost (BITC)	$6,110,000
Contingency	$1,527,000
Total Installed Cost (TIC)	**$7,637,000**

Refer to Appendix F, Capital Cost for additional details.

10.3.2 NET PRESENT VALUE (NPV), INTERNAL RATE OF RETURN (IRR), AND PAYBACK PERIOD

ConDex Base Case

Case	**50:50 Winter / Summer**	**67:33 Winter / Summer**
NPV ($)***	$25,409,135	$29,207,755
IRR	33.0%	36.5%
Payback Period (years)	3.2	2.9
NPV***/Tonne CO_2 Abated	$25.50	$26.37
Capex/Tonne CO_2 Abated	$7.67	$6.90

***@8% Hurdle Rate

ConDex Alternative Case

Case	Includes Assumed Carbon Levy	
	50:50 Winter / Summer	67:33 Winter / Summer
NPV ($)***	$46,125,181	$52,235,050
IRR	49.5%	54.5%
Payback Period (years)	2.2	2.0
NPV***/Tonne CO2 Abated	$46.29	$47.16
Capex/Tonne CO2 Abated	$7.67	$6.90

***@8% Hurdle Rate

Refer to Appendix G, Economic Model for additional details.

11.0 TECHNO-ECONOMIC EVALUATION

Evaluation metrics were established recognizing the differences in Inproheat's Submerged Combustion (SubCom) Technology and Combustion & Energy Systems' Condensing Economizer (ConDex) Technology. Metrics were agreed with COSIA to be used to evaluate each on an individual basis.

The responses compiled below came from the following sources:

- Phase 1 Technology Supplier Data (refer to Appendix C & D)
- Technology Supplier Budget Quotes (refer to Appendix C & D)
- Energy & Material Balances (Refer to Section 7.0 & 8.0)
- Water Chemistry Evaluation (Refer to Section 9.0)
- Economic Evaluations (Refer to Section 10.0)
- Techno-Economic Questionnaire (refer to Appendix C & D)

The responses relate to the supplied equipment and not to the additional equipment and piping integrating the technology into the existing facility.

11.1 SUBCOM

Metric	Response
11.1.1: Comparison of the Technologies	
Reduction in GHG emissions, as compared to the mine reference facilities Auxiliary Boiler Steam Generation	Refer to Section 8.0, Energy Modelling Results
Economic: a. CAPEX ($ CDN) including major / warehoused spares b. OPEX ($ CDN/yr) c. Evaluation of NPV, payback and IRR using input variables from COSIA	Refer to Section 10.0, Economic Evaluation
11.1.2: Metrics for go/no go on the technology application to a particular site	
Impact of technology integration on the temperature of heating recycle Process Water (ΔT, °C)	Refer to Section 8.0, Energy Modelling Results
Impact on recycle Process Water chemistry (e.g., pH, etc.)	Refer to Section 9.0, Water Chemistry Evaluation
Environmental emissions and effluents (air and water) a. By-products and their characteristics b. Waste products and their characteristics	Water: Refer to Section 9.0, Water Chemistry Evaluation (By-product water can be re-used). Air: Refer to Section 13.2.2, NOx Emissions No other by-products or waste products
11.1.3: Metric to understand the operation for a particular application	
Utility requirements: a. Power b. Fuel (e.g., Natural Gas, etc.) c. Chemicals (e.g., for pH adjustment, etc.)	a. & b. Refer to Section 8.0, Energy Modelling Results c.1. Refer to Section 9.0, Water Chemistry Evaluation for discussion on pH. c.2. Per SRC Pilot Testing Report, anti-foam chemical addition may be required.
Plot requirements and integration: a. Approximate footprint (m X m) b. Plot space requirements and proximity requirements to existing plant infrastructure c. Ease of integration into plant facilities	a. 35m x 30m Concrete Foundation (Estimated) b. & c. Refer to Estimated Plot Location in Appendix C.7, Scope Split Schematic & Plot Location
What are the technology's turndown capabilities?	Each burner can be turned down at least 8:1 in our experience, and we have had them operate at 10:1 turndown very comfortably. With a multiple burner system, individual burners can be shut down, so for the four-burner system being considered in the study, turndown capability is 32:1 or better.

Metric	Response
What are the technology's ease of expansion for multiple units? What modifications would be required (if any) as a provision for expansion?	Additional modules can be added to operate in parallel with existing units to increase capacity. No modifications are necessary as each module can be operated independently.
11.1.4: Qualitative Pros/Cons, if applicable	
Any special site (infrastructure) or utility requirements not normally available	No special site or utility requirements.
Performance impairment due to contaminants and process upsets	1. Scale deposits from TDS could restrict the combustion chamber orifices leading to higher backpressure. This does not impair the heating performance unless it reaches the point of "maxing out" the combustion air blower. If deposits form on the upper, non-submerged section of the combustion chamber, it could insulate it from the cooling effects of the liquid and cause an "overheating" situation. A high temperature switch protects against actual overheating. Based on the nature of the TDS in the recycle water, and on pilot test results and observations, scale deposit is not expected to be an issue. 2. Corrosive components in the liquid can cause long term degradation of the wetted parts. The primary concern is for the long term integrity of the tank and its internal appurtenances because they are relatively difficult and costly to repair or replace. The combustion chamber is a replaceable component and can be repaired in most cases if necessary. The selection of materials of construction are key to the long term corrosion resistance, but process upsets that introduce excessive concentrations of corrosive elements could cause accelerated corrosion. 3. Sudden influxes of feed in a range outside the hydraulic design capabilities of the tank could choke the flow through the HRU/tank and cause backup or flooding. 4. Loss of feed to the tank will cause the burners to ramp down the firing rate and eventually shut down. Interlock of feed is recommended to alarm then shut down burners.

Metric	Response
What are potential process hazards associated with the technology and what safety considerations have been incorporated into the technology's design?	The burner system is designed, manufactured and certified to the CSA B149 standards governing gas fired appliances, and electrical wiring and panels are CSA inspected and certified. The minimum pre-purge time as prescribed by CSA B149.3-15 eliminates the possibility of any fuel in the gas passages that could ignite in an explosive manner during trial-for-ignition. The exhaust gases are vented to atmosphere through an outlet nozzle on the HRU section of the tank. It is the only outlet for the exhaust as the rest of the tank is sealed to prevent their escape into the work zone due to low levels of CO and NO_x. Heating contents to >60°C introduces the potential for burns if direct contact is made with hot components. The tank surfaces are insulated for heat conservation so will protect against burns to personnel. The exposed part of the burner does not reach temperatures that could cause burns to personnel.
Technical gaps or environmental trade-offs associated with the SubCom and ConDex technologies that may require further study	No technical gaps were seen. Refer to Section 13.0, Future Considerations for items to be considered prior to installation.
11.1.5: Vendor Information	
Would COSIA members have access to future improvements to the technology?	Absolutely! We encourage it.
Experience list (Client references) and production capacities	Refer to Appendix C.6, Techno-Economic Questionnaire
Licensing requirements, if any	None.
List of proprietary equipment (provided by Vendor)	Combustion Chamber Heat Recovery Unit (HRU) Foam removal appurtenance in tank

Metric	Response
Maintenance requirements - turnaround time	Typical expected maintenance – The only pieces of rotating equipment are the combustion air blowers. The recommended maintenance operations are: - Oil change twice a year - Grease bearings monthly - Inspect drive alignment every 6 months - General state inspection every 6 months - Clean inlet filter as necessary For other SubCom components: - Inspect burner annually for condition of ceramic throat and general wear/corrosion and replace if necessary - Inspect tank internals annually for signs of wear - Inspect combustion chamber annually - Calibrate pressure safety switches annually - Leak test gas safety shutoff valves annually - Inspect instruments quarterly - Inspect flow control valves annually - Inspect and clean tank of any accumulated solids that have settled in the tank Maintenance requirements are influenced by the operators' attention to following proper operational procedures. Ensure that all recommended interlocks with equipment/functions beyond battery limits are installed and functional.
Materials of Construction	Refer to Appendix C.3, Budgetary Quote for SubCom materials of construction. The SubCom Heating Tank has been quoted as 2205 Duplex Stainless Steel. Coated carbon steel was considered, but it was determined to be very challenging to coat due to the limited work space inside the tank.
Control philosophy, ease of integration into mine control (DCS) facilities	Refer to Appendix C.3, Budgetary Quote for SubCom discussion on control philosophy. Inproheat scope of supply includes PLC and HMI panel as well as independent burner safety management systems. Signals can be sent to plant DCS as required.
Engineering and operating support, availability to provide start-up support	Engineering, Operating and Maintenance Manuals, Installation Supervision, Commissioning Services and Operator Training are provided by Inproheat. Refer to Appendix C.3, Budgetary Quote details.
Winterization Requirements	SubCom Heating Tank is insulated. All Process Water piping is insulated and electric heat traced.

11.2 CONDEX

Metric	Response
11.2.1: Comparison of the Technologies	
Reduction in GHG emissions, as compared to the mine reference facilities Auxiliary Boiler Steam Generation	Refer to Section 8.0, Energy Modelling Results
Economic: a. CAPEX ($ CDN) including major / warehoused spares b. OPEX ($ CDN/yr) c. Evaluation of NPV, payback and IRR using input variables from COSIA	Refer to Section 10.0, Economic Evaluation
11.2.2: Metrics for go/no go on the technology application to a particular site	
Impact of technology integration on the temperature of heating recycle Process Water (ΔT, °C)	Refer to Section 8.0, Energy Modelling Results
Impact on recycle Process Water chemistry (e.g., pH, etc.)	Refer to Section 9.0, Water Chemistry Evaluation
Environmental emissions and effluents (air and water) a. By-products and their characteristics b. Waste products and their characteristics	Water: Refer to Section 9.0, Water Chemistry Evaluation (By-product water can be re-used). Air: Existing Flue Gas from the Auxiliary Boiler is vented through a new stack (cooled Flue Gas). As part of Budget quote clarifications, C&ES confirmed that they can supply a 30 m stack in lieu of the stack quoted. The increased stack height is within the accuracy of the budget quote provided. No other by-products or waste products.
11.2.3: Metric to understand the operation for a particular application	
Utility requirements: a. Power b. Fuel (e.g., Natural Gas, etc.) c. Chemicals (e.g., for pH adjustment, etc.)	a. & b. Refer to Section 8.0, Energy Modelling Results c. Refer to Section 9.0, Water Chemistry Evaluation
Plot requirements and integration: a. Approximate footprint (m X m) b. Plot space requirements and proximity requirements to existing plant infrastructure c. Ease of integration into plant facilities	a. 30m x 15m Concrete Foundation (Estimated) b. & c. Refer to Estimated Plot Location in Appendix D.7, Scope Split Schematic & Plot Location
What are the technology's turndown capabilities?	The ConDex system fan/VFD has a turndown capability of 10:1. When the modulating flue gas inlet damper is included in the turndown capability calculation, the turndown capacity improves to 16:1.

Metric	Response
What are the technology's ease of expansion for multiple units? What modifications would be required (if any) as a provision for expansion?	The ConDex system can easily be expanded to recover heat from multiple sources, and expanded water flows. Depending on the volumetric rate of expansion the ConDex fan capacity may have to be increased, as well as water supply pressure potentially.
11.2.4: Qualitative Pros/Cons, if applicable	
Any special site (infrastructure) or utility requirements not normally available	No special site or utility requirements.
Performance impairment due to contaminants and process upsets	There are no anticipated performance impairments due to contaminants on the flue gas side of the ConDex system. If a contaminant causes fouling on the water side in the exchanger it can be cleaned during maintenance downtime. For any process upsets the ConDex system will adjust to water/flue gas flow variations. The system will shut itself down automatically if process flows drop below minimum setpoints.
What are potential process hazards associated with the technology and what safety considerations have been incorporated into the technology's design?	Because the ConDex system is independent from the boiler/GT operation (no dampers used to restrict or redirect flue gas flow) there are no known process hazards. Both the water and flue gas flows are passively connected to the existing process. Any process upsets in the ConDex system will result in the ConDex system shutting down and isolating itself and the existing process will continue its normal operation.
Technical gaps or environmental trade-offs associated with the SubCom and ConDex technologies that may require further study	No technical gaps were seen. Refer to Section 13.0, Future Considerations for items to be considered prior to installation.
11.2.5: Vendor Information	
Would COSIA members have access to future improvements to the technology?	Yes. Any improvements to the system design would be immediately available to COSIA members.
Experience list (Client references) and production capacities	Refer to Appendix D.6, Techno-Economic Questionnaire
Licensing requirements, if any	None.
List of proprietary equipment (provided by Vendor)	The ConDex exchanger design and operation control philosophy are considered proprietary.
Maintenance requirements - turnaround time	Instrument calibration and fan moving part maintenance are the only typical maintenance requirements, along with annual exchanger inspection corresponding to performance data monitoring.

Metric	Response
Materials of Construction	Refer to Appendix D.3, Budgetary Quote for ConDex materials of construction. As part of Budget quote clarifications, C&ES confirmed that they have experience using Duplex 2205 for the ConDex Exchanger tubes and the tubes can be changed from 304SS to Duplex 2205 within the accuracy of the budget quote provided.
Control philosophy, ease of integration into mine control (DCS) facilities	Refer to Appendix D.3, Budgetary Quote for detailed controls strategy. The supplied PLC control panel will interface with the Boiler DCS / BMS via Ethernet connection and wired interlocks.
Engineering and operating support, availability to provide start-up support	Site Supervision, Commissioning and Training Services are provided by Combustion & Energy Systems. Refer to Appendix D.3, Budgetary Quote for details.
Winterization Requirements	The ConDex exchanger is shipped insulated and clad. New ducting to tie-in to existing stack will be insulated. All Process Water piping is insulated and electric heat traced.

12.0 SUMMARY

Both Inproheat's Submerged Combustion (SubCom) Technology and Combustion & Energy Systems' Condensing Economizer (ConDex) Technology are technically viable alternatives to traditional Hot / Warm Process Water generation (steam generation via Auxiliary Boilers or GTG / HRSGs and shell and tube steam condensers). Both systems have been installed in industrial facilities and are currently advanced enough to be installed as a prospective pilot in an Oil Sands facility.

The installation of either the SubCom or ConDex instead of an equivalent Auxiliary Boiler, would also eliminate the requirement for expansion of the following equipment / systems:

- DMW Water Treatment
- Deaerators
- Boiler Feed Water Pumps
- Steam Generation Blowdown
- Additional Hot Process Water Heat Exchanger area (in the case of ConDex, it reduces the potential addition)

As the technologies can both produce hot water, but in two dramatically different ways, there was not an attempt to directly compare SubCom and ConDex. Each technology was evaluated independently to determine the GHG savings against the traditional method of Hot Process Water generation (steam generation via Auxiliary Boilers or GTG / HRSGs and shell and tube steam condensers).

12.1 SUBCOM

SubCom units provide an emissions savings compared to conventional steam generation methods of heating. This emissions savings is generated by the increase in thermal efficiency between steam generation and SubCom as Natural Gas is combusted in both technologies.

The potential duty production from a SubCom Unit is significant, with two units able to supplement close to a typical Auxiliary Boiler duty. This would potentially allow a facility to utilize a SubCom unit(s) in lieu of Auxiliary Boilers during the expansion of a mine or in the construction of a new mine (for water heating purposes only). See Section 8.0, Energy Modelling Results for additional details.

With the NPV, IRR and Payback periods shown in Section 10.0 Economic Evaluation, the SubCom technology on its own is financially challenged when evaluating the installation feasibility versus utility savings alone (when idling existing steam generation equipment).

With the available duty of the SubCom units and its ability to replace the comparable duty of a boiler, there may be opportunity savings when installing a SubCom unit in lieu of a new Auxiliary Boiler (criteria has not been evaluated in this study).

In a green field or system capacity expansion application, Inproheat's SubCom technology is promising in that a similar order of magnitude total installed cost can provide an equivalent amount of heated Process Water while providing the benefit that the following systems would not need to be expanded:

- Demineralized Water Treating
- Condensate Polishing
- Blowdown System
- Process Water Exchangers

12.2 CONDEX

The ConDex technology provides a notable emissions savings by improving the operating efficiency of conventional steam generation methods of heating. The emissions reduction is created since the ConDex provides all of its duty from the boiler or GTG/HRSG flue gas, thereby not creating any additional emissions (no additional Natural Gas firing required). See Section 8.0, Energy Modelling Results for additional details.

With the NPV, IRR and Payback periods shown in Section 10.0 Economic Evaluation, the ConDex technology has significant financial potential based on the economic model (even without accounting for carbon avoidance credits). This is supported by the high NPV/Tonne CO_2 Abated and low Capex/Tonne CO_2 Abated.

13.0 FUTURE CONSIDERATIONS

The following items should be evaluated further for a prospective pilot installation in an Oil Sands Facility.

13.1 GENERAL

13.1.1 PROCESS CONTROLS

As part of this review, process controls were not evaluated. For either technology, process controls need to be reviewed in detail to ensure that the new technology operates seamlessly with the existing facility. The process controls will also be site specific depending on the existing system configuration.

13.1.2 MATERIALS OF CONSTRUCTION

Materials of construction were provided by Inproheat and Combustion & Energy Systems as part of their budgetary proposals; however a detailed materials review will be required based on the site specific water compositions and site preferences.

13.1.3 WATER CHEMISTRY

General observations from Section 9.0, Water Chemistry Evaluation should be validated to confirm the impacts on the site water system chemistry. It may be prudent to add chemical injection points to the system for potential future requirements.

13.1.4 INSTALLATION

The impact to current operations and extent of downtime for construction would need to be considered with the installation of either technology.

13.2 SUBCOM

13.2.1 PUMP NPSH

The pump required to return heated Process Water from the SubCom technology to the mine's existing hot Process Water system may have a high Net Positive Suction Head requirement (NPSHr). As the operating pressure of the SubCom unit is around atmospheric pressure and the vapor pressure is near atmospheric pressure (due to high outlet temperature), there may not be adequate NPSH available. The NPSH will need to be carefully considered in the overall system design.

Potential options to mitigate are:

- Select lower NPSHr pump
- Elevate the SubCom Tank to increase the liquid level elevation
- Select canned pumps

13.2.2 NOX EMISSIONS

Impact of the SubCom NOx emissions needs to be considered in the site specific air permitting.

13.2.3 TANK FOAMING

The SRC Pilot Testing Report noted foaming issues in the SubCom tank at high outlet temperatures which interfered with tank level transmitters and caused process interruptions. The system needs to be further evaluated for selection of appropriate, anti-foam chemical addition that will not impact downstream operations. Level transmitter type selection will need to consider potential tank foaming. Inproheat has a patented design which has been used commercially for mechanically dealing with foam issues which can be considered in lieu or in conjunction with of anti-foam chemicals.

13.2.4 SYSTEM ODOR

The SRC Pilot Testing Report noted that the Process Water received had a strong odor due to Benzene, Toluene and Xylene. Further testing will be required to ensure that the full size SubCom system will not cause site odor issues due to the potential presence of these contaminants in the flue gas stack. Site specific Process Waters will need to be tested for expected levels of Benzene, Toluene, Xylene, and any other anticipated odor releasing contaminants.

13.3 CONDEX

13.3.1 CONDENSATE BASIN EVALUATION

As part of the ConDex design, a condensate collection basin is provided downstream of the ConDex exchanger to collect produced water from the flue gas. Basin design will need to be reviewed in detail to ensure it can provide adequate NPSH for the Flue Gas Condensate Pumps.

13.3.2 HIGH OUTLET TEMPERATURE

The Phase 2 summer case results in high Process Water outlet temperatures (95°C to 97°C). Site specific further evaluation is required to determine if excessive fouling is anticipated in the ConDex exchanger. The trade-off between hotter water and more duty will need to be considered.

13.3.3 HOT PROCESS WATER PUMPS

As part of this study, the hydraulics between the source and destination tie-ins for the Process Water eliminates the need for Hot Process Water Pumps. Further site specific evaluation would be required to determine if Hot Process Water Pumps are required.

13.3.4 INDIRECT HEATING

The “Direct” Heating Method was selected for the Phase 2 Economic evaluations. Site specific water system configuration may make the “Indirect” Heating Method where a cleaner (minimal fouling) fluid passes through the ConDex tubes, which is subsequently passed through another exchanger bank to heat the Process Water a better selection.

13.3.5 BOILER FLUE GAS PLUME DISPERSION

The impact of the lower flue gas temperature on the site flue gas dispersion plume needs to be evaluated.

Appendices

Appendices have been removed for confidentiality purposes.

Please contact Technology Supplier directly for any additional details.