



For Emissions Reduction Alberta

Final Project Report

Project Title: Upgrading Pilot Plant
Agreement Number: G130035
Project Leader: Lisa Doig
Lead Institution: Field Upgrading Limited

Project Advisor: Duke DuPlessis
Project Period: May 30, 2014 to December 31, 2016
Project Budget: \$29.1 million
ERA Funding: \$8,928,600

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Executive Summary

The project objective was to design, build and operate a 10 Barrel per day (Bpd) pilot plant in Fort Saskatchewan, Alberta using Field Upgrading's proprietary DSU® technology. Appendix 1 shows the DSU process using pictures of the pilot plant. The primary goal of the project was to scale the technology from a bench scale, batch operation to a larger continuous process at pilot scale to further prove the technology and gather the data necessary to design a commercial unit. We were very close to the original project plan although the budget and timeline expanded. We will operate the pilot plant a year longer than initially anticipated. Early on we struggled in making the sodium flow and then experienced stress corrosion cracking in some process areas. Both issues underestimated and unanticipated. As we worked to improve the process, we developed new IP related to the maturation/solids separation process. These are the reasons for building a pilot and we likely have similar types of "learnings" with our next stage 2500 Bpd CleanSeas demonstration plant.

<i>Project Schedule</i>		<i>Cost Status</i>	
(1)	<input type="checkbox"/> Project on schedule	(1)	<input type="checkbox"/> Cost on budget
(2)	<input type="checkbox"/> Project delayed	(2)	<input checked="" type="checkbox"/> Cost overrun
(3)	<input type="checkbox"/> Project cancelled	(3)	<input type="checkbox"/> Cost underrun
(4)	<input checked="" type="checkbox"/> Project complete		

Key Outcomes:

1. We successfully scaled up the DSU technology from the lab to the pilot, building a pilot facility that has been operating for over a year.
2. The pilot plant operated without incident during the project period.
3. Four different feedstocks have been processed into a saleable DSU product. These feedstocks represent a range of feedstock qualities we will likely process in a commercial operation. Three of the feeds are local Alberta product.
4. We completed testing to gather the design data for the reactor scale-up. During this testing we have been able to reduce the reactor pressure which will greatly improve the capital cost and expand the number of potential vendors to fabricate the reactor.
5. We confirmed scaleup of the E-Cells, specifically the NaSICON membrane, and have commenced design a commercial style prototype E-Cell that we will test in mid 2017.
6. We developed and filed patents on new intellectual property related to the solid separation process and removal of residual sodium.
7. We started the design basis memorandum work (DBM) for the next stage commercial demonstration plant.
8. Our technology continues to reflect the Greenhouse gas benefits we have originally projected. We estimate a GHG reduction between 5-20% to baseline, noting that 75% of the emissions are indirect based on footprint of grid supplied power.

FIELD Upgrading™

The original project budget was \$24.2 million. Over the project period of May 30, 2014 to December 31, 2016, the project budget was revised to \$29.1 million. Supporting funding from CCEMC/ERA was \$8,928,600 or approximately 30%.

Project Description

The project objective was to design, build and operate a 10 Bpd pilot plant in Fort Saskatchewan, Alberta using Field Upgrading's proprietary DSU® technology. The primary goal of the project was to scale the technology from a bench scale, batch operation to a larger continuous process at pilot scale to further prove the technology and gather the data necessary to design a commercial unit. Appendix 1 shows the DSU process using pictures of the pilot plant.

Technology Description

The DSU® process is a disruptive approach to surgically removing sulphur and metals from heavy oil. At the same time, the DSU® process is simple, scalable (to fit into sea container-size skids) and has no direct SO_x, NO_x or GHG emissions and it doesn't leave big piles of coke or asphaltenes behind. The key to the process is sodium, a powerful reducing agent with a strong affinity for sulphur and metal atoms interspersed in the complex heavy oil molecules.

DSU® Process Overview

The DSU process can be separated into three main process sections as described below.

1. **Reactor:** Sodium, hydrogen and heavy oil are mixed in a reactor. The sodium preferentially seeks out and eliminates sulphur and metal atoms from the heavy oil molecules. Hydrogen capping of the open molecular bonds created during the removal of sulphur and metals results in lower-weight molecules that make the product oil 'lighter' without removing coke or asphaltenes. The resulting DSU® product contains very low levels of sulphur and metals – and is also much lighter and less viscous than the original feed.

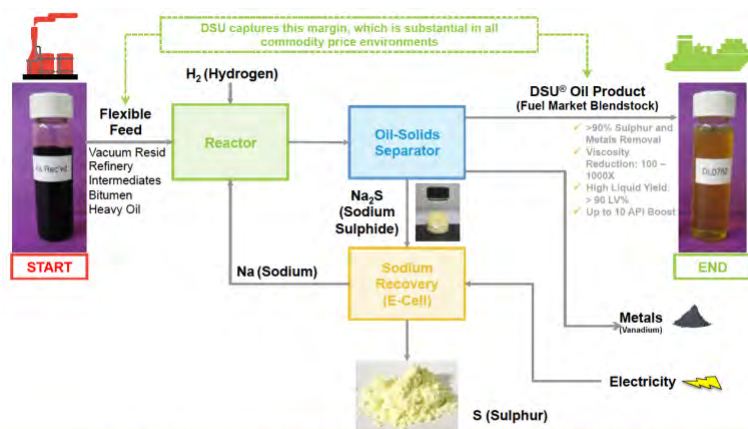


Figure 1: The DSU® Process

2. **Oil-Solids Separator:** The oil leaving the reactor contains solids, which are primarily sodium sulphide and metals. These solids are separated from the oil using centrifuges. The solid sodium sulphide is then dissolved in a solvent which is fed to the electrolysis cells (E-Cells). The metals do not dissolve and are recovered as a saleable by-product.
3. **Sodium Recovery:** The dissolved sodium sulphide is introduced to a bank of E-Cells. When electricity is applied across the cells, sodium is separated from the sodium sulphide and recycled back to the reactor. The ability to recover the sodium and reuse it in the reactor

makes the DSU® process unique and commercially viable. Sulphur is potentially a saleable by-product of the sodium recovery process.

Project Goals

We are very close to the original project plan although the budget and timeline expanded. Early on we struggled in making the sodium flow and then with stress corrosion cracking in the reactor area process vessels and piping. The pilot was built and has been operating for over a year and gathered sufficient data to design the next phase commercial demonstration plant. We will continue to operate it through 2018 to gather additional data to support commercialization and process optimization.

The original objectives listed in Table 1 below were still the objectives at the conclusion of the project. Table 1 also shows the final outcomes at the completion of the project.

Table 1: Summary of Project Objectives and Outcomes

Original Objectives	Final Outcomes
To demonstrate the safe and reliable operation of the MSU process in a large scale pilot plant (~10 Bpd) using heavy oil as the feed.	<ul style="list-style-type: none"> • We have processed 4 representative feedstocks including Alberta Bitumen • We operated the pilot plant without incident during the project period. Appendix 4 includes the testing planned. • We had originally planned longer-term runs of up to 1000 hours but have shortened them to progress through testing a greater variety of feedstocks at the pilot. Average run length for 2016 was 50 hours as we tested a range of feedstocks. This helped understand the effect of the differences of the feedstock qualities primarily sulphur and viscosity on the operation and to better characterize the range of the technology as we develop the design criteria for a commercial plant. For 2017 we expect to complete longer runs to refine the operation and collect process efficiency data.
To demonstrate the economic and environmental advantages of the MSU process.	<ul style="list-style-type: none"> • With the small size and intermittent operation of the pilot we were not able to fully measure assess the environmental impacts. • We were able to reaffirm the capital and operating estimates matching the lab and pilot data.
To demonstrate the scalability of the MSU process and in particular the sodium/bitumen reactor and sodium regeneration electrolysis cells.	<ul style="list-style-type: none"> • The lab results were confirmed in the pilot • The reactor kinetics were confirmed. • Both the reactor and E-Cells have been proven to scale from the lab. • Results are included in Appendix 2 and 3

<p>To collect the detailed data required to design and build a commercial demonstration plant of the MSU process.</p>	<ul style="list-style-type: none"> • We completed testing to gather the design data for the reactor scale-up. During this testing we have been able to reduce the reactor pressure which will greatly improve the capital cost and expand the number of potential vendors to fabricate the reactor. • At the project outset we anticipated our next stage scale-up to be to a 1000 Bpd. This was our initial estimate due to the size limitation of the reactor to fit within a modular transmodal sized skid. With the success of the pilot testing and input from Ekato, experts at reactors and agitators, we decided that we would scale to 2500 Bpd capacity rather than 1000 Bpd as first planned. This is now the commercial design capacity which we will complete the next stage engineering.
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Outcomes and Learnings

Project Outcomes:

The project is completed with the following outcomes.

We successfully scaled up the DSU technology from the lab to the pilot, building a 10 Bpd pilot facility that has been operating for over a year.

1. Four different feedstocks have been processed into a saleable DSU product as shown in Appendix 2. These feedstocks represent a range of feed quality we will likely process in a commercial operation. Three of the feeds are local Alberta product ranging from heavy bottoms to vacuum residue as well as bitumen.
2. We completed testing to gather the design data for the reactor scale-up. Pilot test results have confirmed:
 - Reaction kinetics of the sodium-sulphur reaction proceed by a zero-order mechanism. Feedstocks with a sulphur content below 5.1 wt% have successfully been desulphurized to at least 0.5 wt% S. Sodium reaction efficiency achieves the same results as the lab, although with higher stoichiometric ratio that requires slightly more sodium.
 - Optimal reaction operating conditions have been confirmed.
 - Hydrogen consumption across the range of feedstocks is similar to lab testing.
 - Continuous operation was confirmed for extended periods. The pilot plant completed 13 runs in 2016 with the longest run time of 70 hours as listed in Table 2.
3. During this testing we have been able to reduce the reactor pressure from level initially tested in the lab. This will greatly improve the capital cost and expand the number of potential vendors to fabricate the reactor.
4. Confirmed scaleup of the NaSICON membrane and have commenced design a commercial style prototype E-Cell that we will test in mid 2017. We confirmed E-Cell scale-up by testing a 4 tall scaffold configuration of commercial sized membranes (Appendix 3). With this technical risk mitigated we restarted the design of the pilot eSkid that will allow us to test larger commercial prototypes of E-Cells. It arrived to the pilot site in Q1 2017. In parallel

we continue to look for alternative solvents to boost E-Cell performance to reduce capital. We have also engaged an electrochemical cell company to assist in the design of a commercial E-Cell and will test a first prototype in mid 2017.

5. We examined the opportunities for waste heat integration, especially given the highly exothermic reaction with sodium and sulphur. Appendix 6 contains the Waste Heat Integration Study completed for the project. Using the heat for power generation has a payout of 6-7 years. A better alternative identified was to optimize the heat balance of the overall plant. For example, we determined that we could remove the bulk of the heat of reaction by feeding oil to the reactor at a greatly reduced temperature and reducing the cooling system duty and design. We will study further opportunities as we progress the process design.
6. Finally we started the design basis memorandum work (DBM) for a 2500 Bpd commercial demonstration plant. A mass balance for the pilot is shown in Appendix 5.

Table 2. 2016 Pilot Run Summary

Run number	Date start	Date end	Feed	Volume feed	Volume product	Run time
				M3	M3	hours
1	03-Feb	21-Feb	VR	2	2	60
2	01-Mar	07-Mar	VR	2	2	54
3	30-Mar	31-Mar	VR	0	0	15
4	05-Apr	11-Apr	Bitumen	4	4	55
5	04-May	05-May	Bitumen	0	0	3
6	18-May	19-May	Bitumen	1	1	13
7	06-Jun	13-Jun	Bitumen	1	1	14
8	20-Jun	21-Jun	Bitumen	1	1	13
9	19-Jul	20-Jul	VR	2	2	41
10	29-Aug	01-Sep	Bitumen	4	4	70
11	17-Oct	23-Oct	VR Blend	2	2	27
12	16-Nov	20-Nov	VR Blend	5	5	78
13	07-Dec	13-Dec	Heavy Bottoms	3	3	43
			TOTAL	27	25	486

We tested an alternative separation process that improved solid agglomeration and thus solids separation. Initial runs increased the occurrence of plugging in the lines as solids dropped out earlier than expected. We will continue to refine the operating parameters as we expect this will reduce the size and number of vessels for a commercial plant. We have also begun testing on a low cost additive that will reduce the residual sodium concentration in the DSU® product so that we meet the marine specification of less than 100ppm. Patents have been submitted for these new processes.

Lessons Learned

As expected in pilot, there are many learnings when a technology scales from bench to pilot and we will continue to have more learnings as we progress to next stage commercial scale. In terms of lessons learned, making molten sodium flow continuously was by far the largest challenge as described in more detail in the Sodium Handling section below.

Sodium Handling: From the beginning, we struggled with the molten sodium feed system to the reactor especially during the first month of pilot plant operations. The root problem is that molten sodium ‘freezes’ easily which makes it very difficult to pump into the high pressure reactor. Figure 2 shows the sodium plugging up on the inlet to the reactor.

Figure 2: Sodium plugging in the reactor



In the pilot plant we overcame this problem by eliminating the pumps and using ‘pressure transfer’ or shot pot (Figure 3). We recognized that this is not a realistic solution at a commercial scale. Thus we went on to successfully demonstrate a standalone high pressure sodium pumping design and incorporated into the design for the upcoming reactor scale-up test.

Figure 3: Sodium Shot Pot



We now have a lot of hard-won learnings on heating and handling molten sodium that we will apply forward at commercial scale.

Reactor Materials: As part of the design data gathering with the pilot, we had planned a corrosion study to determine reactor metallurgy by including coupons through the skid. The metallurgy required to contain the reaction of sodium and sulphur is challenging due to the potential for

caustic stress corrosion cracking. We completed a corrosion study based on coupons installed within the reactor vessel that were exposed to run conditions for a number of months. The range of metallurgy evaluated for reactor construction includes carbon steel, stainless steel, Ni-200 and Inconel alloys. A dual 316/316L SS was chosen as the material of construction. After a specific run we had a number of occurrences of caustic stress corrosion cracking in the fittings and in the 'underflow' piping downstream of the reactor. Tracing it back we realized that the feedstock had picked up water while at offsite storage. Subsequent lab testing determined that over 0.1% water accelerates stress corrosion cracking. Going forward we have put an operating procedure in place that involves heating the feedstock by circulation in the tank until the water level in the feed is below 0.1% to ensure enough water is removed prior to introducing it into the reactor. We will confirm its success through further testing and incorporate a similar system in the commercial design.

E-Cell Operation: We have completed a number of lab scale E-Cell tests using Na₂S solids made both in the lab and the pilot with results that match our E-Cell target performance criteria of 65mA/cm² with summary results shown in Appendix 3. However we have not made enough Na₂S solids in the pilot to run long enough to fully confirm this operating range and to understand the long term impacts to E-Cell operation. This is planned for mid 2017. This coupled with the new and cheaper E-Cell solvent will confirm the design data necessary for the demo plant.

Market Adoption: From a market perspective we first expected that the Canadian oil sands business would be our target, hence the company name Field Upgrading. With the drop in oil prices and the confirmation of an implementation date by the IMO for sulphur reduction in fuel oil, we have determined the best initial market is the marine fuel market with our target customers not necessarily producers but refiners or integrated producers. The sulphur concentrated bottoms stream from a refinery, typically blended and sold into the bunker pool, is smaller closer to 10,000 Bpd. Thus we have reduced our typical project size from 25,000 Bpd to 10,000 Bpd but will evaluate this in terms of economics.

Greenhouse Gas and Non-GHG Impacts

The pilot design and markets for our technology continue to reflect the Greenhouse gas assumptions and resulting benefits we have originally projected. Initially we identified two markets 1) SAGD Upgrading Refining: Partial upgrading before downstream refining to transportation fuels, and 2) Low Sulphur Bunker fuel. We have added an additional case that compares our DSU® marine fuel product with marine diesel produced by conventional crude in a standard refinery. This is the product that is typically used as proxy for low sulphur marine fuel in the market today. The table below shows we still have a significant GHG advantage, especially considering the majority of the emissions are power to the E-Cells which is indirect and dependent on your location.

Table 3: GHG Reduction

	Refinery	Marine Original	- Marine Diesel
	GHG Reduction to Baseline		
At start of Project	94%	92%	
At close of Project	94%	77%	88%

Note: This estimate was completed by Lenef Consulting

This project was also supported by funding provide by Sustainable Development Technology Canada (SDTC). As a result we had an additional third party, approved by SDTC, complete the required final environmental assessment report. As they were not as familiar with heavy oil processing nor marine fuel they struggled to find standard baseline and project estimates. In our view they overestimated the bitumen footprint but underestimated the marine fuel impact, so perhaps the overall total is within a range. They did provide a full assessment of the additional environmental benefits showing the very low NOx, SOx and PM associated with the DSU® technology relative to alternatives. Table 3 summarizes they assessment with the full report included in Appendix 7. The full report includes the estimated environmental benefits of a full rollout of the technology to 2030.

Table 4: Bloom DSU Environment Assessment Summary

Bitumen Feedstock	CO2e (kg/bbl Marine fuel)		SOx (kg/bbl Marine fuel)		NOx (kg/bbl Marine fuel)		PM (kg/bbl Marine fuel)		CO (kg/bbl Marine fuel)		VOC (kg/bbl Marine fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline	151	10%	0.13	8%	0.12	13%	0.02	10%	0.06	12%	0.03	11%
Project	138	6%	0.04	4%	0.16	6%	0.01	6%	0.07	6%	0.02	6%
Reduction from Baseline	13	139%	0.10	11%	-0.04	47%	0.01	22%	-0.01	81%	0.01	25%
VR Blend Feedstock	CO2e (kg/bbl Marine Fuel)		SOx (kg/bbl Marine Fuel)		NOx (kg/bbl Marine Fuel)		PM (kg/bbl Marine Fuel)		CO (kg/bbl Marine Fuel)		VOC (kg/bbl Marine Fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline Scenario	69	7%	0.13	7%	0.13	9%	0.02	8%	0.06	9%	0.01	7%
Project	55	5%	0.07	8%	0.16	8%	0.01	10%	0.07	8%	0.03	9%
Reduction from Baseline	14.3	42%	0.06	18%	-0.03	56%	0.00	69%	-0.01	79%	-0.01	20%

As stated earlier we examined the opportunity for waste heat integration. Although it did not economically support power generation there is still an opportunity to utilize the low grade heat for steam or as a means to pre-heat the oil into the process. These will be integrated into the design going forward to further improve the environmental footprint of the DSU technology.

Scientific Achievements

The Figure 4 shows the number of patents and current status in various countries. As of project end we have 23 granted, 41 pending patents and are filing patents on the new maturation and polishing processes.

Figure 4: Patent Summary

Identifier	CA	CN	EU	IN	JP	MY	MX	SG	KR	UAE	US
Base Electrolysis	Granted										Granted
Heat and Hold	Granted	Granted	Granted		Granted	Granted	Granted	Granted	Granted	Granted	Granted
Solids Drying	Granted		Granted		Granted			Granted	Granted		Granted
H2S capping gas	Granted		Granted		Granted			Granted	Granted		Granted
TAN Reduction	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted
L/L Sulphur Separation	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted	Granted
CH4 Capping gas	Granted	Granted	Granted	Granted	Granted				Granted		Granted
Retort Integration	Granted						Granted				Granted
Sequential Staging	Granted		Granted	Granted	Granted			Granted	Granted		Granted
H2S Na Removal											

Granted	Pending
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We discovered in the lab that the oil product coming out of the reactor has high levels of residual sodium even after all the sodium sulphide solids are removed. These levels are too high for most markets, including the marine bunker fuel market. Since then we have developed a proprietary process for removing this residual sodium that is very simple but works well. We have successfully tested this process in both the lab and the pilot plant. Based on the pilot plant data – a residual sodium “polishing unit” has been included in the scope of the Clean Seas™ Demonstration Plant. From this we have filed patents on new intellectual property related to improving the solid separation process and the removal of residual sodium.

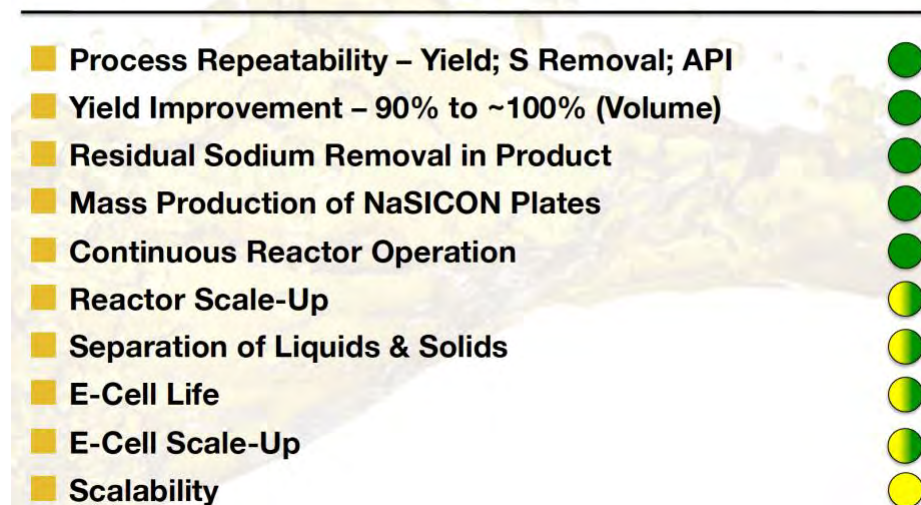
We have filed for trademark of our technology (DSU™) and company (Field Upgrading Limited™).

Overall Conclusions

Significant milestones have been achieved to derisk the technology as of the end of the project as shown in Figure 5. The primary areas of process scale up from lab scale have been validated with continuous reactor operation confirmed.

Figure 5: DSU Technology Status

Technology De-Risking Status



Further Development

We will continue to operate the pilot project as there are still areas requiring further research and testing to support commercial design as listed below:

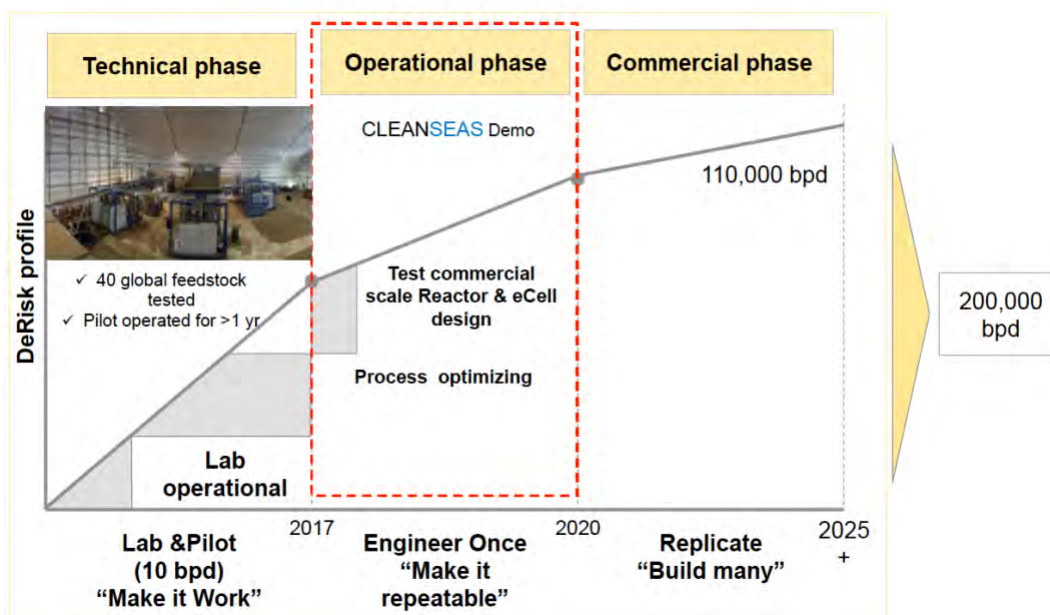
- *Solids Maturation:* Although we have 13 separate runs and almost 500 hours of operation on the reactor in 2016 plus another 700 hours in the first quarter of 2017 we continue to have intermittent plugging problems with solids dropping out of the reactor slurry before we reach the solids separation stage. We believe this may be a function of the small piping in the pilot plant and will not plague us commercially with a larger plant. However in parallel we will relook at the design of the maturation vessel.
- *E-Cell Development:*
 - We continue to look for more stable and cheaper solvents to be used with the E-Cell as the solvents we are currently using generate some H₂S.
 - We are researching alternative membrane manufacturing to reduce cost and increase strength.
 - The design of the commercial E-Cell modules must be optimized for efficient manufacturing. This scale-up process is currently underway with progressive prototypes being tested at the pilot plant. We are working with Ceramatec and their parent, CoorsTek, to refine the NaSICON plate design and to tailor their existing manufacturing facilities to meet our requirements. We are also working with Noram, a specialized industrial electrolysis engineering firm based in Vancouver with a fabrication arm, to develop the commercial-scale E-Cell prototype which “packages” the NaSICON plates. Commercial prototypes will be fabricated and tested in 2017 to provide the data to continue to refine the design for the demo.

- **Impurities Impact:** To avoid fouling, it is critically important that little to no hydrocarbon makes its way through the separation process to the E-Cells. Our ‘firewall’ is a dryer or kiln that will bake-off hydrocarbon from the sodium sulphide solids before it reaches the E-Cells. The pilot plant includes a small-scale commercial drier. Recent runs at the pilot plant have shown that the produced solids are quite clean however we will continue to test this longer term in 2017 to determine any impacts from the build up of impurities. We believe there are further opportunities to reduce capital equipment within the process especially in the area of solids separation.

Next Steps

Figure 6 depicts the next steps and timeline in the progression of the technology. We are moving from the technical phase of lab and pilot testing to the next phase of operating with the focus on process optimization and confirming commercial scaleup before the final phase of commercial rollout.

Figure 6: DSU Technology Progression



CleanSeas Commercial Demonstration

The International Maritime Organization (IMO) ratified the timing for the implementation of the 0.5% S global low sulphur marine fuel standard. This new standard will start in 2020. Since this announcement we have seen an increase in global interest. This change to regulations offers the once-in-a-lifetime market opportunity for our DSU technology. As part of our commercialization plan we felt it was useful to have a better understanding of the current market as we investigate the marine fuel opportunity. We engaged Turner Mason & Company (<http://www.turnermason.com>) to complete a market pricing study to evaluate the economics of locations for a commercial plants— US Gulf Coast, Westcoast and Alberta. Using their forecast

they show an improved netback when using DSU® to convert bitumen directly to a value added end product of low sulphur bunker fuel rather than as a refinery feedstock. Thus we have focused on having first oil from a commercial demonstration plant by the end of 2019 and begun the design basis memorandum or feasibility study on the design of the modular 2500 Bpcd demonstration project.

Looking longer term we recognize there are additional opportunities and markets for the DSU technology that will require further research both technically and economically to determine viability.

These include:

- *Metals Removal:* A number of refinery companies have shown interest in the ability of DSU to remove metals from their refinery feedstock rather than sulphur. This has the potential to improve their catalyst life and thus reduce costs. We successfully completed a proof-of-concept test for a Chinese refinery company but will require further study to determine ideal conditions and economics.
- *Solids Co-Processing:* DSU technology has the potential to remove sulphur from any heavy hydrocarbon which includes asphaltenes or petroleum coke. We successfully completed a proof-of-concept test using samples provided by companies that show asphaltenes can be processed and 10% pet coke can be mixed with heavy oil. Further study will be required to evaluate the impact on the product quality in terms of stability for further processing.

Communications and Knowledge Transfer

We set up an Advisory Committee that includes four major oil companies, a large bunker trader (Sterling Fuels) and representatives from the Canadian and Alberta governments. The Advisory Committee meets roughly quarterly and provides guidance and expertise to Field while giving the Committee members first hand access to new results. Of course, the Committee also gives us the opportunity to engage the oil companies in partnering and licensing discussions. We are continuing our Advisory Committee through the next phase and have expanded the membership to include Irving Oil. We have found it is an excellent means to engage with potential customers and interested stakeholders.

Presentations and Events

- We had an open house at the pilot site in June 15, 2016 with over 50 people in attendance.
- We presented at World Heavy Oil conference in September 2016 in Calgary, Alberta and Alberta Innovates Technology forum in November 2016.
- The International Bunker Industry Association conference in Gibraltar, UK in November, 2016.
- We presented the project at the Heartland Stakeholder event in January 2017. This is an audience of 600 local stakeholders, industry leaders and government and media.

With the potential market opportunity related to the marine industry, we realized our technology name “Molten Sodium Upgrading” or MSU, although descriptive, was not helpful when talking



with people less chemical process focused. As a result we changed MSU to DSU and have left off the process description. We have since trademarked the DSU name.

We have started developing the next stage 2500 Bpd commercial demonstration project. We have named this project CLEANSEAS™ to reflect the focus to produce value-added direct-to-ship low sulphur marine fuel. To kick off our CLEAN SEAS™ Demonstration project to the public and start the regulatory dialogue we setup a new website for this project - www.cleanseas.ca.

Final Financial Report

The original project budget was estimated as \$24.2 million and subsequently revised to \$29.1 million. ERA/CCEMC supporting funds were \$8,928,600 or approximately 30% of the project. The project involved building and operating a pilot plant so no product was made for sale thus no revenue was received related to this project. The project was also supported by funding from SDTC of \$5.45 million.

Table 5 shows the budget and actual spend per milestone and cost category.

Table 5: Project Financial Summary

Milestone	Task	Costs (\$ in 000s)	Budget (\$ in 000s)	Actual Cost (\$ in 000s)
1	Complete design for the 10 Bpd MSU Pilot Plant	Labour	\$67	\$67
		Capital/Materials	\$46	\$46
		Subs	\$7,290	\$7,290
		Travel	\$51	\$51
		Other	\$26	\$26
		Sub-Total for Milestone 1:	\$7,481	\$7,481
2	Fabricate, install and commission Pilot	Labour	\$190	\$49
		Capital/Materials	\$44	\$242
		Subs	\$3,485	\$3,530
		Travel	\$55	\$49
		Other	\$20	\$93
		Sub-Total for Milestone 2:	\$3,794	\$3,962
3	Conduct robust test plan	Labour	\$935	\$215
		Capital/Materials	\$30	\$518
		Subs	\$8,624	\$11,968
		Travel	\$61	\$147
		Other	\$74	\$821
		Sub-Total for Milestone 3:	\$9,723	\$13,668
4	Develop commercialization plan	Labour	\$192	\$174
		Capital/Materials	\$12	\$26
		Subs	\$3,266	\$3,339
		Travel	\$70	\$72
		Other	\$453	\$681
		Sub-Total for Milestone 4:	\$3,993	\$4,286
		Total	\$29,105	\$29,398

Appendix 1: DSU in Pilot in Pictures

The DSU® Process – In Pictures

PILOT PLANT SITE (HOUSES ALL THE SKIDS)



REACTOR SKID



SEPARATION SKID



E-CELL SKID



Appendix 2: Pilot Plant Results

Appendix X - Pilot Plant Results

Pilot Results

Lab matches Pilot

	Lab		Pilot		
Property	Vacuum Residue Blend	DSU Product	Feed: VR	DSU Product	DSU Product Blend (est)
Product Yield (volume%)		97%	-	>90%*	>95%
API Gravity	12.4	19.0	14.5	14.8*	17.6
Sulphur (wt%)	2.1	0.06	1.8	0.17*	0.13
Carbon (wt%)	86.2	85.7	86.8	85.9	86.0
Nitrogen (wt%)	0.6	0.4	0.4	0.3	0.3
Hydrogen (wt%)	10.4	11.2	10.7	11.1	11.9
Viscosity @ 50°C (cSt)	807	235	253	234*	<200
Vanadium (wppm)	86	1	88	3	3
Nickel (wppm)	35	1	33	4	3
Na Residual (ppm)	55	45	33	N/A	N/A

* DSU product not including light ends

Key Achievements

- One Year Incident Free
- Found “Sweet Spot” for running vacuum resid
- DSU process meets Marine Fuel Specification
- Successful repeat runs for new solids separation process (*great solids!*)
- Successfully demonstrated new polishing process
- Runs with multiple feedstocks shows repeatability and reliability of process
- New E-Skid operating
- Successfully “holding the line” on long term E-Cell run
- Solvent clean-up via distillation confirmed if needed
- Much cheaper solvent works!

Key Challenges

■ **Process Design still in development** - *Pilot plant to run through 2017*

- ... pushing polishing to lower temp to eliminate heat exchangers*
- ... confirming drying process for solids quality suitable for eCells*
- ... running alternative feeds as backup to refinery bottoms feeds for Demo*
- ... running pilot solids*

■ **Water in Feedstock**

- ... water accelerates Stress Corrosion Cracking*
- ... management system in place – and working*

■ **E-Cells**

- ... some H₂S-Make ... scrubbing required in Demo*
 - longer term solvent optimization program kicked-off*
- ... optimizing operating conditions (confirming in E-Skid)*
- ... fast-tracking testing of new “cheap” solvent*

Pilot Results

	Raw Bitumen #1	LS VR #1	LS VR #2	Refinery Bottoms
	Feed			
Flowrate (kg/h)	65.8	65.9	65.9	65.8
Density ~ 60 F (kg/m3)	985	969	992	1015
Volumetric Flowrate (bpd)	10.1	10.3	10.1	9.7
Sulfur (wt%)	4.59%	1.81%	1.74%	2.10%
	Product			
Sulfur (wt%)	0.31%	0.23%	0.45%	0.51%
NaSR	1.25	1.44	1.26	1.24
Density (kg/m3)	954	966	978	996
Viscosity @ 50 C (cSt)	~250	151	336	592
	Product Mass Yields			
Liquid (wt%)	94.50%	97.30%	98.10%	98.00%
Gas (wt%)	0.50%	0.50%	0.20%	0.60%
Solid (wt%)	5.00%	2.30%	1.40%	2.66%
Carbon in Solids (wt%)	2.60%	10.10%	3.20%	0.85%
V+Ni in liquid (ppm)	34	12	32	40

Pilot Learnings

■ Metal Failures:

- Occurred in the first 48 hours – in the underflow areas only
- Cause likely Caustic SCC from pickling prior to startup
- Detailed analysis and lab work to recreate the failures
- Coupons were installed and monitored

■ Sodium Handling:

- Heat tracing, heat tracing and more heat tracing!
- Designed a new sodium transfer mechanism

■ Operability:

- R-skid operates reliably for extended periods
 - Good understanding of plant behaviour
-

Results Summary

- Desired target product sulfur achieved on feedstocks
 - API increase is directly correlated with extent of sulfur removal
 - Metals reduced by 60+%
 - TAN removed completely
 - Significant viscosity reduction
 - Olefins >1% but this may be reduced by running at higher pressure
-

Appendix 3: ECell Results

E-Cell Results Summary

■ Sulphur Separation and Na recovery demonstrated

■ Tested various eCell configurations:

Successfully completed

- ✓ Single V0 ran for over 1400 hours
- ✓ Multi cell V0

Scale up testing

- V1 (2 inch to 6 inch)
- V2 (4 inch commercial membrane)
- V2 scaffold design (4 membranes in a row)




1. Summary Log of eCell testing at site

Figure 1 is the listing of eCell testing at site in the eCell micro skid. We tested single and multiple cell configurations of up to 8 membranes.

Figure 1: eCell event log

Module	Description	First Power (if applicable)	Final Power (if applicable)	Cumulative Powered Run Time (Hours)	Membrane ID
V0-1-012	First electrolysis module operated at the Fort Saskatchewan pilot plant.	October 5, 2015	October 20, 2015	49.5	061014 (091614) Plate #21
V0-1-013	First turbulence promoter module. Pressure drop was too large to register anolyte flow though the module. Promoter mesh relatively fine compared to later promoters.	October 21, 2015	October 21, 2015	0.1	Unknown
V0-2-001	First multi-cell module ever. 2 cathodes with a common central anode. Cathode sodium lines plumbed in parallel. Disassembly revealed only one cathode primed.	October 22, 2016	October 23, 2016	26.5	0302615GY (Plate #2) 061014GY (Plate #85) 020614GY (Plate #23) 102114GY (Plate #4) 020614GY (Plate #20) 040314GY (Plate #18) 102114GY (Plate #9) 102114GY (Plate #8) 102114GY (Plate #5) 040314GY (Plate #4) 102114GY (Plate #21) 102114GY (Plate #14) 102114GY (Plate #4) 102114GY (Plate #3)
V0-8-001	8-cell module. 4 cathodes with shared anodes. Cathodes were plumbed in parallel and did not prime evenly. Module rebuild in Fort Saskatchewan as V0-8-002.	October 30, 2015	November 2, 2015	4.3	102114GY Run #1 (Plate # 102114GY Run #19 ID of last 2 membranes i unknown
V0-8-002	Rebuilt V0-8-001. Cathodes were plumbed in series to ensure all chambers were primed. Module removed when current decayed to <5mA/cm ² and did not recover. Module shipped intact to Ceramtec.	November 12, 2015	November 26, 2015	153.3	
V0-2-002	Installed when V0-8-002 current decayed. Attempted to use graphite for anode plate but seal could not be made. Used Pt-SS anode instead. Removed when current density decayed.	December 15, 2015	January 7, 2016	59.2	102114GY (Plate # 22) 102114GY (Plate #13)
V0-1-012 (2nd tour)	Added solids directly to run tank in attempt to make mass balance more accurate; module quickly clogged with undissolved solids.	January 7, 2016	January 11, 2016	25	061014 (091614) Plate #21
V0-1-014	Single-cell module installed to replace clogged V0-1-012 (2nd tour). Removed when current density declined.	January 14, 2016	January 30, 2016	234.6	061014GY (091614) (Plate #84) 040314GY (062714)
V0-1-015	Installed to replace V0-1-014. Removed due to low current density and small anolyte leak. Attempted to ship intact to Ceramtec, shipment was denied. Module dismantled in Fort Saskatchewan, components remain at pilot plant.	February 1, 2016	February 2, 2016	16	Reused from assembly V013
V0-1-014 (2nd tour).	Installed when V0-1-015 developed a minor leak. Removed due to anolyte leak. Module dismantled in Fort Saskatchewan, discovered small fracture in membrane. All components shipped to Ceramtec along with components of V0-2-003.	February 2, 2016	February 4, 2016	30.6	061014GY (091614) (Plate #84)
V0-2-003	Rebuilt from components of V0-2-002 in Ft Sask. Catastrophic failure with large anolyte leak after >230 hours of run time and 2 solids additions. One membrane completely destroyed, the other intact. Shipped to Ceramtec along with components of V0-1-014.	February 4, 2016	February 15, 2016	234.2	???
V0-1-016	Single-cell module. Removed for V1 dummy flow test.	February 23, 2016	March 28, 2016	754.2	CT-EG-333 Plate #7
V0-1-016 2nd tour	Single-cell module reinstalled after V1 dummy flow test. Removed for V1-1-001 test.	March 31, 2016	April 11, 2016	251.2	CT-EG-333 Plate #7
V1-1-001	First 6x6 vulcanized membrane with turbulence promoter. High pressure drop due to rubber seal protruding into anode-NASICON gap. Membrane destroyed.	April 12, 2016	April 13, 2016	0	Unknown
V1-1-002	V1 module without turbulence promoter. High pressure drop, eventually determined to be caused by rubber seal protruding into anode-NASICON gap. First time anolyte pressure is actively balanced on sodium side of cell.	April 13, 2016	April 14, 2016	0	Unknown
V0-1-016 3rd tour	Single-cell module. Removed when current became unusually erratic.	April 14, 2016	April 25, 2016	250	CT-EG-333 Plate #7

Appendix 4: Pilot Test Program

	Project: DSU 10 bpd Pilot Plant	Rev: 1
	Title: Reactor Skid Experimental Program	Date: Nov 10, 2015
		Page: 1 of 2

1.0 Summary of Reactor Skid Experimental Test Program

Test #1 – System Characterization

Purpose:

1. Run R-skid with Feedstock
2. Heat system up in preparation for initial reaction runs
3. Characterize heat losses in reactors (R-201/221) and maturation tanks (V-301/311) to determine baseline for heat of reaction calculation
4. Determine Critical speed (rpm) for maturation tank agitator
5. Determine hydrogen flowrate for Test #2 and #3 (gassed and ungassed reactor levels)

Test #2 – System Characterization – Initial Reaction

Purpose:

1. Initial reaction of Na with Oil at low throughput (3 bpd) and “optimal conditions” from the laboratory
2. Learn to control, and the behavior of, sodium, oil and hydrogen flowrates
3. Evaluate product quality as a function of hydrogen flowrate (calculate single pass hydrogen uptake)
4. Initial Reaction kinetics, residence time and scale up (including initial estimates of k_{La})
5. Directionally evaluate product quality and hydrogen uptake as a function of reactor impeller rpm

Test #3 – System Characterization - Full Capacity Operation

Purpose:

1. Increase throughput of reactor in stages – 6 bpd and 10 bpd
2. Continue to learn to control, and the behavior of, sodium, oil and hydrogen flow rates
3. Monitor single pass hydrogen uptake with increasing throughput
4. Identify a preliminary relationship between reaction and maturation steps by evaluating the impact of maturation time on product quality
5. Compare the product quality from both a single reactor and two reactor in series
6. Initial Reaction kinetics and reactor scale up (residence time)

Test #4 – Parametric Testing – Reactor Temperature

Purpose:

1. Confirm results from laboratory testing – $T > 330\text{ C}$ to remove G/L mass transfer limitation
2. Bump tests and repeatability
3. Determine product quality (and solids PSD?) variations with temperature

Test #5 – Parametric Testing – Reactor Impeller Speed

Purpose:

1. Impact of rpm on single pass H_2 uptake, yield and product quality
2. Impact of rpm on solids PSD (tests assumption that separation difficulties may be a function of excessive lab reactor rpm required to induce gas flow)
3. Initial estimates of k_{La} as a function of impeller speed

Test #6 – Parametric Testing – Maturation Time and Pressure, Impeller Speed


Purpose:

1. Operate reactor at “optimal” conditions,
2. Short bump test on impeller speed – very low and 70% of critical speed to evaluate if rpm impacts product quality.
3. Perform 2 variable mini-parametric test matrix: Maturation time vs Pressure
4. Evaluate impact on separation efficiency, solids PSD and solids yield

Test #7 – Parametric Testing – Reactor Impeller Type

Purpose:

1. Commission two reactors
 - a. R-201 with standard pitched blade impeller with plugged shaft

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	Title: Reactor Skid Experimental Program	Date: Nov 10, 2015
		Page: 2 of 2

- b. R-221 with Ekato gas jet/ phase jet (self aspirating)
2. Reconfirm optimal result from Test #5 in R-201
3. Operate with identical conditions in R-221
4. Compare H₂ uptake vs rpm results from Test #5
5. Repeat certain elements of Test #5 (short bump tests on rpm)

Test #8 – Steady State Operation – Money Run #1 – (50-)100 hrs

Purpose:

1. Maintain steady state operation at optimal conditions to date
2. Focus on operability of Reactor skid
3. Close mass balance, confirm product yield and quality

NOTE: Can be moved up in sequence anywhere up to post Test #2

Test #9 – Parametric Testing – Maturation Pressure

Purpose:

1. Reconfirm results for optimal conditions from Test #6 (or #8 if different conditions)
2. Repeat Test #6 with variations on pressure rather than rpm & maturation time
3. If separation efficiency decreases with pressure, increase maturation time

Test #10 – Parametric Testing – Reactor Pressure

Purpose:

1. Reconfirm results for optimal conditions from Test #6 (or #8 if different conditions)
2. Repeat Test #6 with variations on pressure rather than rpm & maturation time

Test #11 – Parametric Testing – Rangeability of DSU Reactor (if required)

Purpose:

1. Reconfirm results from Test #10 (or #8) - Baseline
2. Narrow scope half factorial parametric Matrix of key variables that are/could be interrelated. Repeatability of previous testing
 - a. Ex. Reactor impeller speed, Reactor residence time, Maturation time.

Test #12 – Steady State Operation – Money Run #2 – 100 hrs

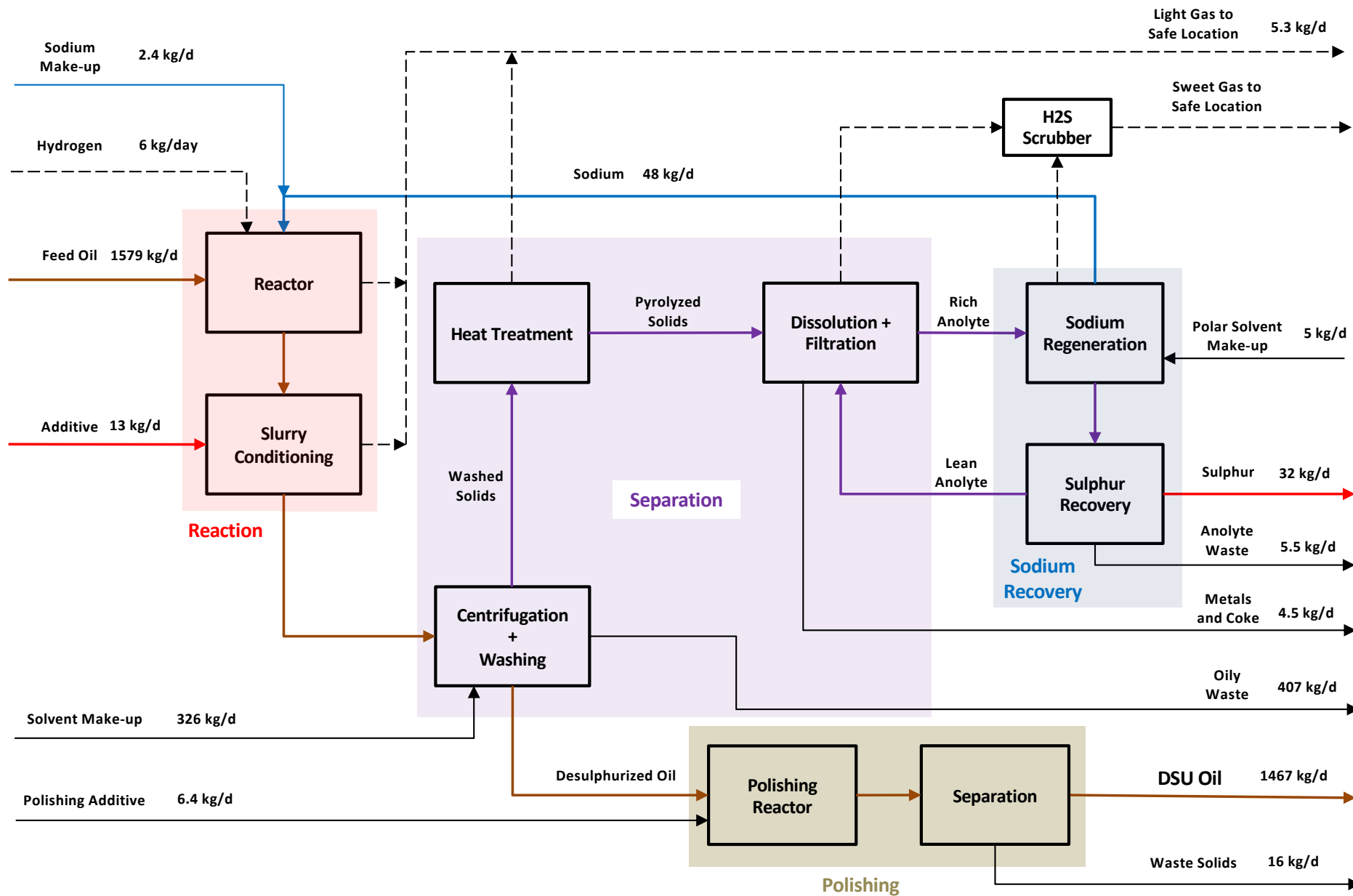
Purpose:

1. Maintain steady state operation at optimal conditions
2. Focus on operability of Reactor skid & information required for DBM
3. Close mass balance, confirm product yield and quality

Appendix 5: Pilot Mass Balance

DSU PILOT PLANT – 10 BPD

(Blended VR)



Appendix 6: Waste Heat Study

Field Upgrading Limited

DSU™ TECHNOLOGY WASTE HEAT RECOVERY STUDY

Document No.: FDU-000-PR-STY-0001

Revision	Date	Revision Notes	Originator	Checker	Approver
A	Mar 23, 2017	Issued for Review	PS	AF	IC
B	May 5, 2017	Issued for Information	PS	AF	IC <i>KE</i>

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1.0 EXECUTIVE SUMMARY

The purpose of this study is to identify and quantify the waste heat opportunities present in the design of the DSU™ Technology. The current DBM phase design of 2500 bbl/d was the basis to identify these opportunities and was extrapolated for a 10,000 bbl/d commercial phase case to quantify the feasibility of waste heat recovery. Three similar processes were identified as possible systems to extract waste heat as efficiently as possible. The Organic Rankine Cycle (ORC) was selected to be the process to analyze in the study due to the ability to select and match working fluids for different heat source temperatures, maximizing efficiency and output. The Steam Rankine Cycle was considered but not selected in this study due to the temperature of the waste heat being lower than 450°C ⁽¹⁾, which results in excess droplet formation in the turbine, reducing efficiency and reliability of the system. The Kalina Cycle is capable of being more efficient than the ORC due to the variable temperature of the ammonia/water mixture at saturated conditions, with a tradeoff of higher cost and more complex process control. This was exempted from the study due to the short timeframe of the study limiting the ability to create a representative model of this system.

Two feasible waste opportunities were identified from the Heating and Cooling Utility Oil System. The first location is the flue gas emitted from OU9-H-915 Heating Utility Oil Heater designated ORC 1 (FLD-0U8-PR-SKT-0001). This case utilizes the Heating Oil exit stream at 100°C as the cold side of an exchanger to absorb heat from the exiting flue gas with an assumed temperature of 350°C. An ORC system with a HFC-245fa working fluid was chosen with the 120°C Heating Oil being the evaporator side of the system and the condensing side of the system utilizing cooling water. The second location selected absorbs the heat from the Cooling Oil Exit stream at 270°C to use in an ORC system designated ORC 2 (FLD-0U8-PR-SKT-0001) with the cooling side of the ORC system being the Heating Oil Exit Stream at 100°C. The working fluid selected for ORC 2 was Toluene. The results from FDU-017-060-01-001 – ORC Waste Heat Calculations attached in the Appendix are displayed below:

Case	2500 bbl/d		10,000 bbl/d		3.5 Year Payback	
	ORC 1	ORC 2	ORC 1	ORC 2	ORC 1	ORC 2
Work Turbine (kW)	50.4	116	201.6	464	5000	5000
Unit Cost (\$/kW)¹	\$5,320	\$3,325	\$2,660	\$2,261	\$1,330	\$1,330
Installation Cost	\$268,128	\$385,700	\$536,256	\$1,049,104	\$6,650,000	\$6,650,000
Payback (years)	14	9	7	6	3.5	3.4

The amount of power that can be extracted from the system is low for the 2500 bbl/d case as expected. The higher unit cost for these small units is uneconomical. With extrapolation to the 10,000 bbl/d case, the higher power extracted results in lower unit costs and reduces the payback. An attempt was made to develop a case of an ORC system that would provide a 3-year payback. But due to the diminishing

¹ (Quoilin, 2013, p 174)

improvement in unit cost as the size of the unit exceeded 200 kW, even a 5 MW ORC system would still have a payback of 3.5 years based on the assumptions of the study.

Ultimately, due to the high payback periods for this application, the advantage of introducing this process to the design is limited unless electricity costs rise, the system is constructed in a remote location with high electricity transmission costs, or a regulatory requirement is mandated to produce power and lower waste heat emissions.

2.0 INTRODUCTION

Waste Heat Recovery has become a necessary consideration in most industrial projects. Often to use the high-value heat associated with gas turbine power generation but more frequently to use the low-grade heat to reduce or offset a facility's power requirement and reduce the environmental footprint of the facility.

Best Engineering practices typically start with early optimization and integration of the heating and cooling systems to reduce their impacts on the capital expense of the facility. Despite the best efforts this often leaves a large volume of low-grade heat from the process to be rejected.

The purpose of this Waste Heat Recovery Study is to examine and compare Waste Heat Recovery processes. The study will then review the current process configuration and quantify what Waste Heat Recovery opportunities exist in a commercial application of Field Upgrading's DSU™ technology.

3.0 PROJECT DESCRIPTION

The marine industry is under increasing pressure to remove sulphur from the heavy oil it uses. Beginning in 2020, the permissible sulphur level in marine fuels used globally will drop from 3.5 to 0.5wt%. Field Upgrading has developed the DSU™ technology and process, which has proven highly effective in pilot operations at removing sulphur from heavy oil, and is targeting the low-sulphur marine bunker fuel market.

The overall scale of the project will be a 10,000 bbl/cd plant composed of four 2,500 bbl/cd cookie-cutter skid-based plants. The 10,000 bbl/cd plant will be fully engineered, but Field Upgrading will lead execution with a 2,500 bbl/cd demonstration plant.

The project will be located in the Fort Saskatchewan area of Alberta, Canada. Feedstocks will be locally sourced refinery and upgrader bottoms with sulphur levels in the range of 2 to 3wt%. Initially, feedstocks will be delivered to the project site by truck, but eventually, they will be delivered by rail. The target sulphur level of the DSU oil product is 0.5wt%. The DSU oil product will be sold by rail primarily to the marine bunker fuel markets in Vancouver, Canada, and the US Northwest.

4.0 WASTE HEAT RECOVERY SYSTEMS

4.1 Steam Rankine Cycle

4.1.1 Process Overview

The Steam Rankine Cycle is the most popular process used to recover waste heat and produce power for plant use or sale. The process requires a pump to feed the water through a multi-pass evaporator to a superheated state. The steam is then expanded through a multistage turbine to drive the shaft to the electrical generator. The water is then cycled back to a condenser so liquid water can be pumped back to the evaporator. The typical use of this process is from flue gasses in high-temperature applications ($>450^{\circ}\text{C}$) such as metal refining furnaces, hydrogen steam reforming plants, and gas turbine/boiler exhaust. The size of these plants varies from 100 kW up to beyond 10 MW.

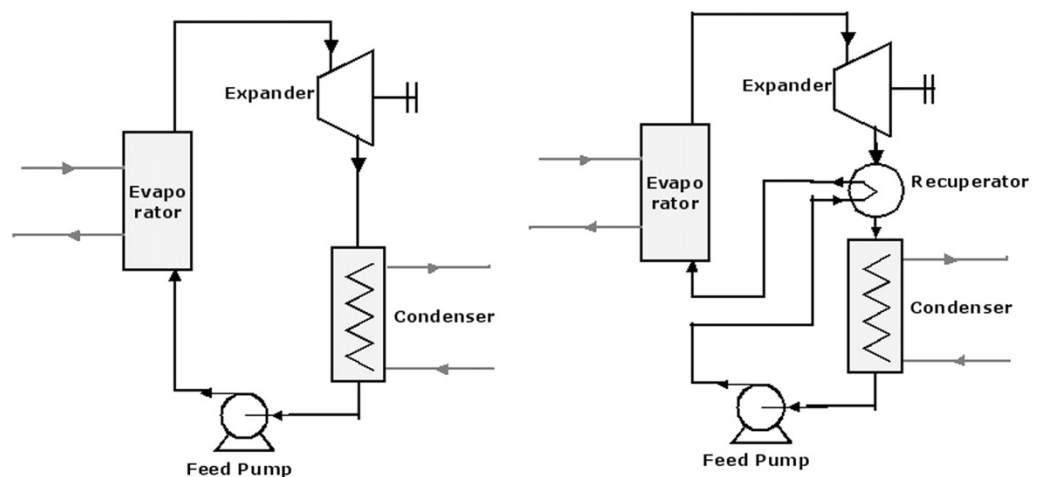


Figure 1: Rankine Cycle Schematic (Quoilin, 2013, p 170)

4.1.2 Advantages and Disadvantages

The high enthalpy of evaporation of water allows for more heat transfer in the evaporator per unit of mass flow. The low mass flow also reduces the pump consumption in the system and increases the efficiency of the process. However, water is required to be superheated in order to prevent excessive liquid formation in the turbine. At evaporation temperatures lower than 450°C , droplet formation occurs during expansion. This increases the wear on the turbine, resulting in lower reliability. As a consequence, more complex equipment and expensive materials are required to counteract the drop in reliability. Finding a different working fluid with a lower boiling point and favorable temperature-entropy (T-s) saturation curve shape is desirable when recovering heat from low-temperature sources.

4.1.3 Hazard Identification

Using water as a medium is ideal from a hazard standpoint. In addition to its high availability and low cost, it is non-toxic, non-flammable, has a low environmental hazard and a high chemical stability. The only hazard present is if two-phase flow is present in the process and water hammer is a concern.

4.2 Organic Rankine Cycle

4.2.1 Process Overview

The Organic Rankine Cycle (ORC) is the standard for converting low-grade waste heat into useful power. The process is similar to the steam cycle with a pump to feed an evaporator and a turbine that expands the working fluid and drives the shaft to the electrical generator. The difference lies in the working fluid, where the process uses an organic fluid in place of water. The most common use of this technology is in geothermal, solar, and waste heat recovery. The typical oil processing heat sources are steam condensate, cooling utility lines, hot process streams, and flue gas from boilers. The sizes for ORC system varies between 50 kW to over 2MW.

4.2.2 Advantages and Disadvantages

The lower boiling point and high vapor pressure versus water allow effective transfer of heat to power when handling temperatures lower than 450°C. Superheating the working fluid is not required due to the right side of the T-s saturation curve of these fluids being near vertical. The higher molecular mass allows for higher mass flows and more efficient turbine efficiencies. However, the lower enthalpy of vaporization requires higher flow rates to achieve the same heat transfer as water, which increases the pump load and decreases the efficiency of the process. However, the limitation of the efficiency of ORC systems is mostly driven by the inherent loss of efficiency with low-temperature cycles vs. high-temperature cycles.

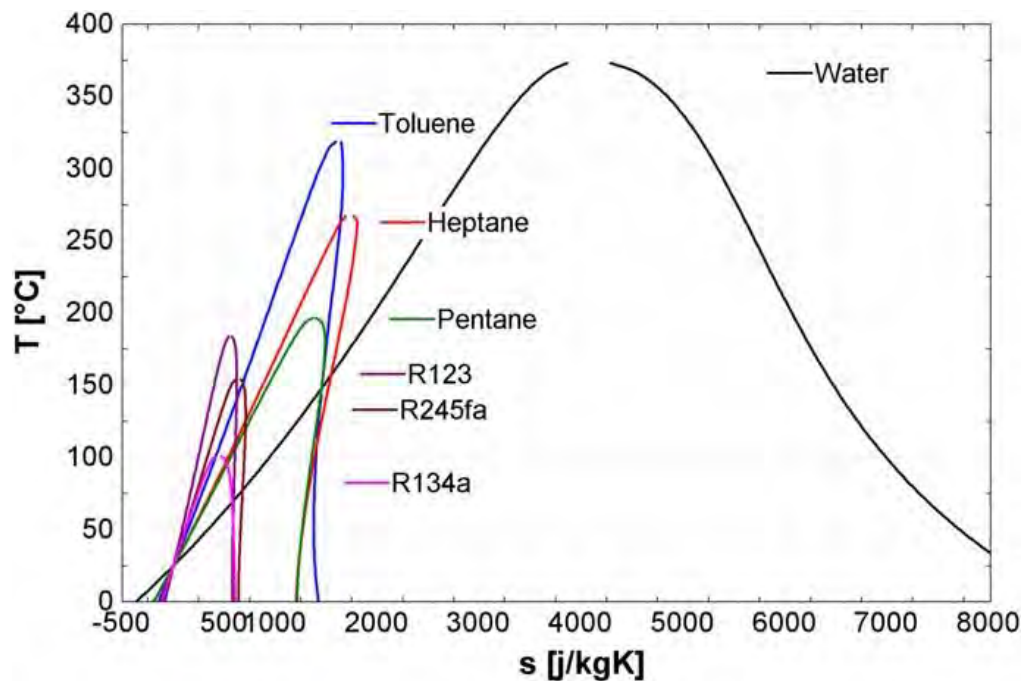


Figure 2: Temperature – Entropy chart of water and different ORC Fluids (Quoilin, 2013, p 174)

4.2.3 Hazard Identification

Selecting ORC working fluids is a compromise between having a fluid with suitable fluid properties, toxicity, ozone depletion potential, greenhouse warming potential, and flammability. The organic fluids chosen in this study are HCFC-245fa and Toluene. HCFC-245fa (Pentafluoropropane) is a hydrofluorocarbon, and has both a high ozone depleting potential and high greenhouse warming potential but is non-toxic. Toluene is an aromatic hydrocarbon with high flammability and moderate toxicity.

4.3 Kalina Cycle

4.3.1 Process Overview

The Kalina Cycle is a proprietary process that utilizes the Rankine cycle but uses an ammonia and water mixture as the working fluid of the process. The mixture exhibits unique behavior when in saturated vapor conditions. As the vapor fraction of the fluid changes, the temperature also changes. This increases the average temperature of the system, and increases the efficiency of the system.

4.3.2 Advantages and Disadvantages

The mix of ammonia and water provides higher efficiencies due to the temperature changing as the vapor fraction of the fluid changes. However, due to the fluid having two components, changing the mixture proportions in different stages in the process is required to attain ideal heat transfer, resulting in additional equipment with more process control. As well, the mixture of ammonia and water is corrosive, requiring careful material selection. The increased complexity drives up the cost.

4.3.3 Hazard Identification

Ammonia is toxic with a 300 ppm IDLH exposure rating, is flammable, corrosive, and toxic to animals. A great amount of care is required to minimize leaks and exposure to heat.

4.4 Comparison Table

Process	Working fluid	Advantages	Disadvantages	Hazards	\$/kW (USD)
Steam Rankine Cycle	Water	<ul style="list-style-type: none"> - High Energy Content - High pump efficiency - High efficiency - High availability - Non-toxic, low environmental hazard 	<ul style="list-style-type: none"> - Needs to be superheated - Droplets form at expansion <450C - Multi-pass evaporator req'd - Multi-stage turbine req'd - Water treatment req'd - More complex system, not completely isolated 	<ul style="list-style-type: none"> - Water hammer in two phase flow 	<ul style="list-style-type: none"> >1MW - \$1100-1400
Organic Rankine Cycle	Toluene Benzene R-134a HFC-245fa Octamethyl-trisiloxane	<ul style="list-style-type: none"> - No superheating req'd - Lower boiling point - Higher molecular weight - Simpler system, single pass evaporators, single stage turbines 	<ul style="list-style-type: none"> - Lower enthalpy of vaporization - Higher flow rates required - More pump load due to low critical temperatures - Lower efficiency - Difficult to find working fluid with desirable fluid properties in combination with low hazard 	<ul style="list-style-type: none"> - High ozone depleting potential depending on product - High greenhouse warming potential - Flammable - Can be toxic 	<ul style="list-style-type: none"> 50-100kW - \$3000-4000 100-1000kW - \$1500-3000 >1MW - \$1000-1500
Kalina Cycle	Ammonia/ Water mixture	<ul style="list-style-type: none"> - High efficiency due to higher average temperature due to temperature change at saturation 	<ul style="list-style-type: none"> - Proprietary technology - Complex system with separators and multiple heaters and evaporators 	<ul style="list-style-type: none"> - High toxicity to humans and animals - Flammable 	<ul style="list-style-type: none"> >1MW - \$1100-1500

Figure 3: Rankine Cycle Comparison Table (BCS, Incorporated, 2008, p 25-27) (Quoilin, 2013, p 174-175)

5.0 HEATING UTILITY OIL SYSTEM

5.1 System Description (FS1-0U9-PR-PFD-9150-01)

The Heating Oil System depicted in FS1-0U9-PR-PFD-9150-01 in the Appendix provides heat for heat exchangers, vessels, and storage tanks in the plant. The Heating Oil in Stream 501 is heated by OU9-H-915 Heating Utility Oil Heater to 360°C, then routed through all process streams that require heating. The Heating Oil then exits the heating loop in Stream 530 at 98°C and absorbs the heat from the exit of the Cooling Oil System through the OU9-E-905 Heating/Cooling Utility Oil Exchanger and routes back to the heater at 270°C.

5.2 Heating Medium

The Heating Oil Medium selected for this study is DOWTHERM-A. This fluid is eutectic mixture of two very stable compounds, biphenyl ($C_{12}H_{10}$) and diphenyl oxide ($C_{12}H_{10}O$). DOWTHERM-A was selected due to the superior thermal stability at a wide range of working temperatures. The working temperature of this fluid is between 15 - 400°C. The desirable properties of this fluid also make it a good candidate for capturing low-grade waste heat and delivering it to a waste heat recovery cycle.

5.3 Waste Heat Opportunities

5.3.1 ORC System #1 - Flue Gas from OU9-H-915 (FLD-0U8-PR-SKT-0001)

The flue gas created from the combustion of fuel gas and air to heat the heating oil provides low-grade waste heat that can be captured and converted to work. An example of how this heat can be captured is seen in Sketch FLD-0U8-PR-SKT-0001 attached in the Appendix. Adjusting the combustion pre-heat allows for a flue gas exit temperature of 350°C in Stream FG3. The heat from the flue gas can be absorbed with the Heating Oil return at EX-3 and heats the oil to approximately 120°C in Stream HO4. An ORC system with HFC-245fa as the working fluid medium and cooling water as the condenser fluid was specified. The system requires the installation of an ORC system, an exchanger to transfer the heat from the flue gas to the heating oil, and a cooling water system capable of 15 m³/hr of flow. This extra equipment can add \$50,000+ to the capital cost. Since the basis of the installed cost of the ORC units in this study is for the units only, it is likely that the payback periods will be greater than what is concluded in the results.

6.0 COOLING UTILITY OIL SYSTEM

6.1 System Description (FS1-0U9-PR-PFD-9151-01)

The Cooling Oil System depicted in FS1-0U9-PR-PFD-9151-01 in the Appendix provides cooling to all the coolers and condensers in the plant. The Cooling Oil in Stream 542 is cooled to 40°C by an Aerial Cooler OU9-E-950 Cooling Utility Oil Cooler. After recovering the heat from the process, the Cooling Oil Return Stream 541 returns at 260°C and the heat is transferred to the Heating Oil Return Stream 530 via the OU9-E-905 Heating/Cooling Utility Oil Exchanger and returned to the Aerial Cooler at 100°C.

6.2 Cooling Medium

The Heating Oil Medium selected for this study is also DOWTHERM-A. See Section 4.2 for details.

6.3 Waste Heat Opportunities

6.3.1 Opportunity - DSU™ Reactor Heat Removal

The exothermic nature of the DSU™ Reactor Vessel and the requirement to extract the excess heat coming from the reaction vessel makes Stream 561 a great waste heat source, releasing approximately 730 kW to the cooling oil. This stream is currently designed to be integrated into the Cooling Oil System. One option is to use this higher grade heat for power generation. However, it is more efficient to use the collective cooling oil return Stream 541 to extract the heat as Stream 561 only has the available energy of 527 kW versus 2766 kW for Stream 541. Utilizing all the heat recovered by the cooling oil will provide more available heat to extract due to the higher flow rate at similar temperatures. Therefore, the better option would be to extract the heat from the entire system, as seen in the next section.

6.3.2 ORC System #2 - Cooling Oil Exit Stream (FLD-0U8-PR-SKT-0002)

The Cooling Oil Stream 541 exits the cooling loop at 280°C. There is an opportunity here to run a Rankine Cycle system alongside the OU9-E-905 exchanger to extract some of the heat from the stream and create power. As seen in Sketch FLD-0U8-PR-SKT-0002 attached in the Appendix, the Cooling Oil stream acts as the evaporator, and the exit steam routes to OU9-H-910 in the Heating Oil system. The Heating Oil side acts as the condenser for the system. The working fluid specified for this ORC system is Toluene. The system requires less additional equipment than ORC System #1. However, the heat extracted for energy production reduces the heating oil temperature and increases the cooling oil temperature, resulting in a higher demand to the heater and aerial cooler. The new duty of the heater with this system in place would be 3525 kW versus 3288 kW for the study case. This corresponds to an increase in CO₂ emissions from 8127 tonnes/year to 8715 tonnes/ year, a 7% increase. Increasing the

size of both the heater and the cooler could add \$50,000+ to the capital cost and increase fuel gas consumption. Since the basis of the installed cost of the ORCs in this study is for the units only, it is likely that the payback periods will be greater than what is concluded in the results.

7.0 RESULTS

As expected, the economic case for waste heat recovery is weak for the 2500 bbl/d project due to the exceedingly high cost per kW in lower outputs. A payback of 9-14+ years is estimated on a scale such as this. However, for a full commercial scale like 10,000 bbl/d, the case is more robust, delivering a payback of 6-7 years. As the duty of the system decreases, the payback improves but has a diminishing return as you exceed the 200 kW range. It is unlikely without an increase of electricity cost that the payback would improve beyond the 3.5-4 year payback period even when considering a 5 MW unit. The ROI can be improved by further optimizing and extracting more work out of the system and an increase in electricity cost. The results from FDU-017-060-01-001 – ORC Waste Heat Calculations attached in the Appendix are displayed below:

Case (Unit Installation Only)	2500 bbl/d		10,000 bbl/d		3.5 Year Payback	
	ORC 1	ORC 2	ORC 1	ORC 2	ORC 1	ORC 2
Work Turbine (kW)	50.4	116	201.6	464	5000	5000
Work Pump (kW)	-3.2	-6	-12.8	-24	-312.5	-263.2
Net Work (kW)	47.2	110	188.8	440	4688	4737
Unit Cost (\$CAD)²	\$5,320	\$3,325	\$2,660	\$2,261	\$1,330	\$1,330
Installation Cost (\$CAD)	\$268,128	\$385,700	\$536,256	\$1,049,104	\$6,650,000	\$6,650,000
Payback (years)	14	9	7	6	3.5	3.4

² (Quoilin, 2013, p 174)

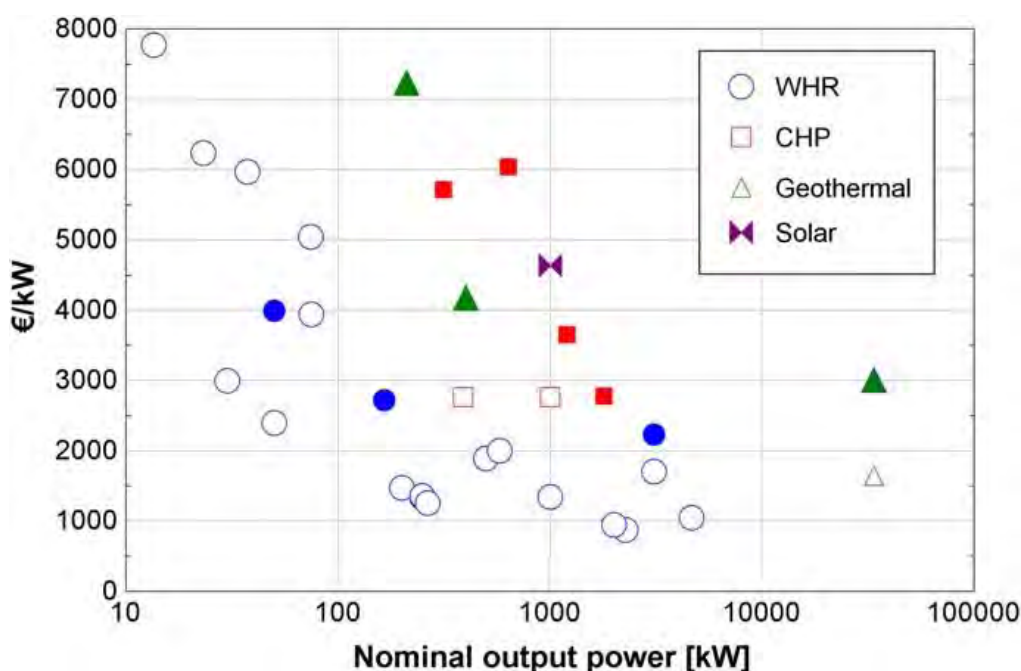


Figure 4: ORC Installation Costs (Quoilin, 2013, p 174)

8.0 RECOMMENDATIONS

8.1 Identified ORC Systems

Two potential sources of waste heat were identified based on the current design of the 2500 bbl/d Plant. The system chosen for both these sources is the Organic Rankine Cycle. The Steam Cycle was omitted due to the working temperatures of the evaporator being below 450°C, making this cycle unfeasible. The Kalina Cycle was omitted due to the complexity of the process, the timeframe, and the limited added value it would provide to the study. The major difference between the Kalina cycle and an ORC is a question of cost vs. efficiency. A more detailed analysis comparing the two technologies is required to select the more economical process.

Both systems come with a compromise to the overall efficiency of the utility system. For the Flue Gas ORC System #1, some of the heat that would otherwise be delivered to combustion air was utilized for the ORC system. This may decrease the efficiency of the OU9-H-915 Heating Oil Heater and increase fuel gas costs. For the Cooling Oil Exit ORC System #2, the system directly impacts and would increase the process demands of both the Heating Oil Heater and the Cooling Oil Aerial Cooler, increasing the power demand for both those units and in the case of the Heater, increasing the CO₂ emissions. Extracting power from these systems

should be pursued at after all other heat integration strategies are exhausted as the efficiency of low-grade waste heat systems are inherently lower than 20%.³

Ultimately, the advantage of introducing this process to the design is limited unless the electricity costs rise, the system is constructed in an isolated location with higher electricity transmission costs, or a regulatory requirement is present to produce power and lower waste heat emissions.

8.2 Other Opportunities

8.2.1 Steam Reforming Hydrogen Plant

The requirement of Hydrogen feed in the DSU™ Reactor process presents an opportunity for waste heat recovery, particularly if the process used to supply hydrogen is via Steam Reforming. The waste heat coming from this system is higher quality than aforementioned opportunities due to the methane having to be heated above 800°C to form hydrogen. The 1.3 MMSCFD SMR plant procured for the 2500 bbl/ CleanSeas project produces export steam from an economizer and a waste heat exchanger that transfers heat from the Reformer outlet high-temperature flue gasses and hydrogen product to the BFW. This produces 2497 kg/hr of steam at a temperature of 200°C. If we assume that the plant demand at commercial capacity is quadruple that at 5.2 MMSCFD, the flow of steam at 200C would be 9988 kg/hr. This steam can either be utilized in a steam cycle for power generation, yielding approximately 1 MW., or the heat can be integrated into the process heat medium to reduce the duty in the Utility Heating Oil Heater.

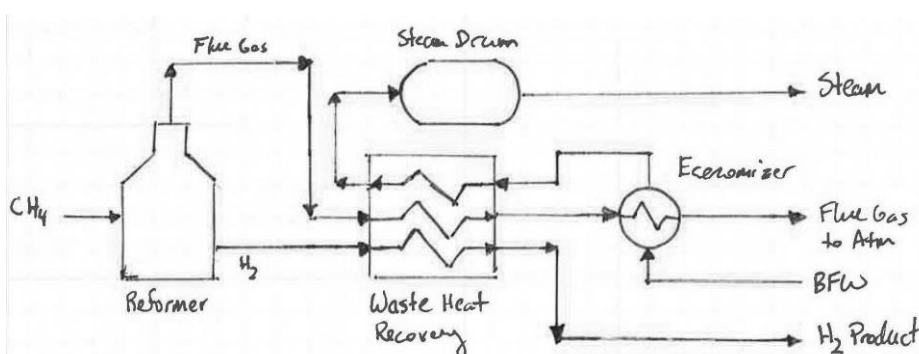


Figure 5: Steam Reformer Waste Heat Recovery Sketch

³ (U.S. Department of Energy, 2008, p 26)

8.2.2 Optimizing Fluid Temperature Specifications

Optimization of the heat balance of the plant is the first step to reducing waste heat. The first steps have been taken to maximize the heat recovery from process streams on both the cooling and heating side. Further optimization as the design develops will improve heat balance of the plant and reduce the cost, reduce environmental footprint, and improve efficiency. An important consideration is the temperature requirements in process streams and storage equipment. One opportunity to decrease the heating demand is to optimize the temperature settings for tank storage. The current heat demand to maintain a 120°C Temperature in the Feed Oil Tank and Off-Spec Product Tank is a combined 7MW. Reducing the tank temperatures to 80°C would decrease the heat demand down to 3MW. This will reduce the process heater duty, reduce operating expense by decreasing fuel demand and fluid medium volume, and reduce CO₂ emissions. Given that the process is highly exothermic, the plant cooling demand should be close to the heating demand. However, due to the high heat demands of the plant as the design currently dictates, the heating demand far exceeds the cooling demand.

8.2.3 Building Heating

Another opportunity to utilize waste heat sources is heating buildings in the plant. Low-grade heat from process streams captured in the heating medium can supply heat to areas of buildings and modules to eliminate electrical or fired heating of air.

8.3 Future Actions

The scope of this report identifies the feasibility of waste heat recovery technologies to the process and touches on the opportunities to optimize the process to minimize waste heat. Future actions as the design phase progresses are required to evaluate further and determine the feasibility of waste heat recovery processes. The recommendation for future actions is as follows:

1. Optimize the process design for the heating and cooling systems by the end of FEED and attain concrete design parameters for the Heating Utility Oil Heater OU9-H-915 and OU9-E-905 Aerial Utility Oil Cooler.
2. Hydrogen Steam Reforming provides an appreciable amount of waste heat. Confirm that this is the process that will be utilized in commercial phases. Undergo the same steps as in this study to determine how to best integrate this waste stream into the process, including the power that can be extracted from this opportunity.
3. Revisit the analysis of the Organic and Kalina Rankine Cycles for the identified low-grade waste heat sources with the updated and optimized heat balance. Determine the feasibility of these process for the 10,000 bbl/d project and incorporate into the design of the plant if the processes are determined to be economically viable.

9.0 REFERENCES

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- (2) U.S. Department of Energy, Industrial Technologies Program (2008). Waste Heat Recovery: Technology and Opportunities in U.S. Industry.
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- (11) Global Cement. Kalina Power Systems in Waste heat Recovery Applications. Retrieved from <http://www.globalcement.com/magazine/articles/721-kalina-cycle-power-systems-in-waste-heat-recovery-applications>. March 2017
- (12) Devco Heaters. Indirect Heaters. Retrieved from <http://www.devcoheaters.com/indirect-heaters/>. March 2017

10.0 APPENDICES

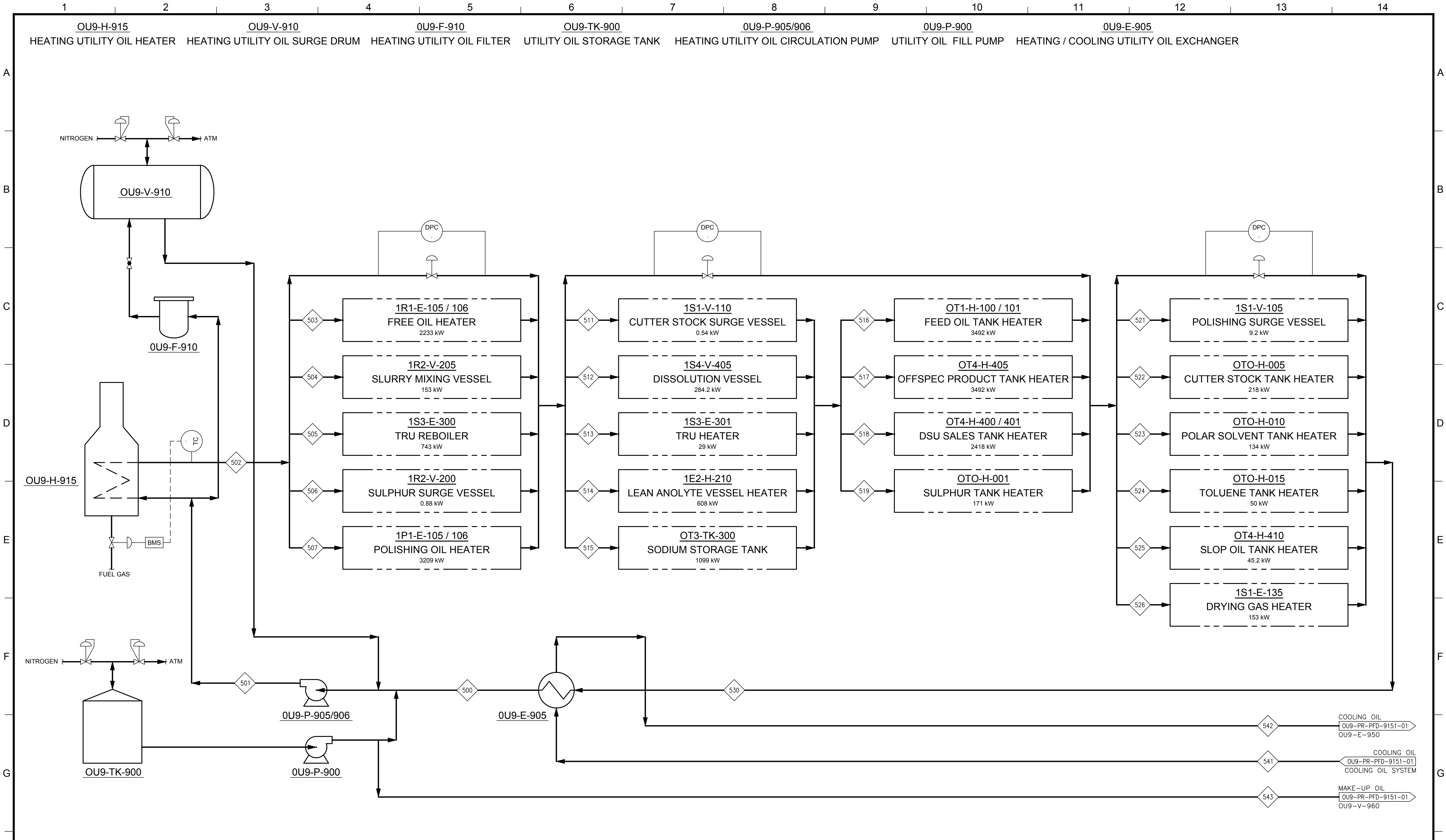
Appendix A - FS1-0U9-PR-PFD-9150-01 – Heating Oil Utility System PFD


Appendix B - FS1-0U9-PR-PFD-9151-01 – Cooling Oil Utility System PFD

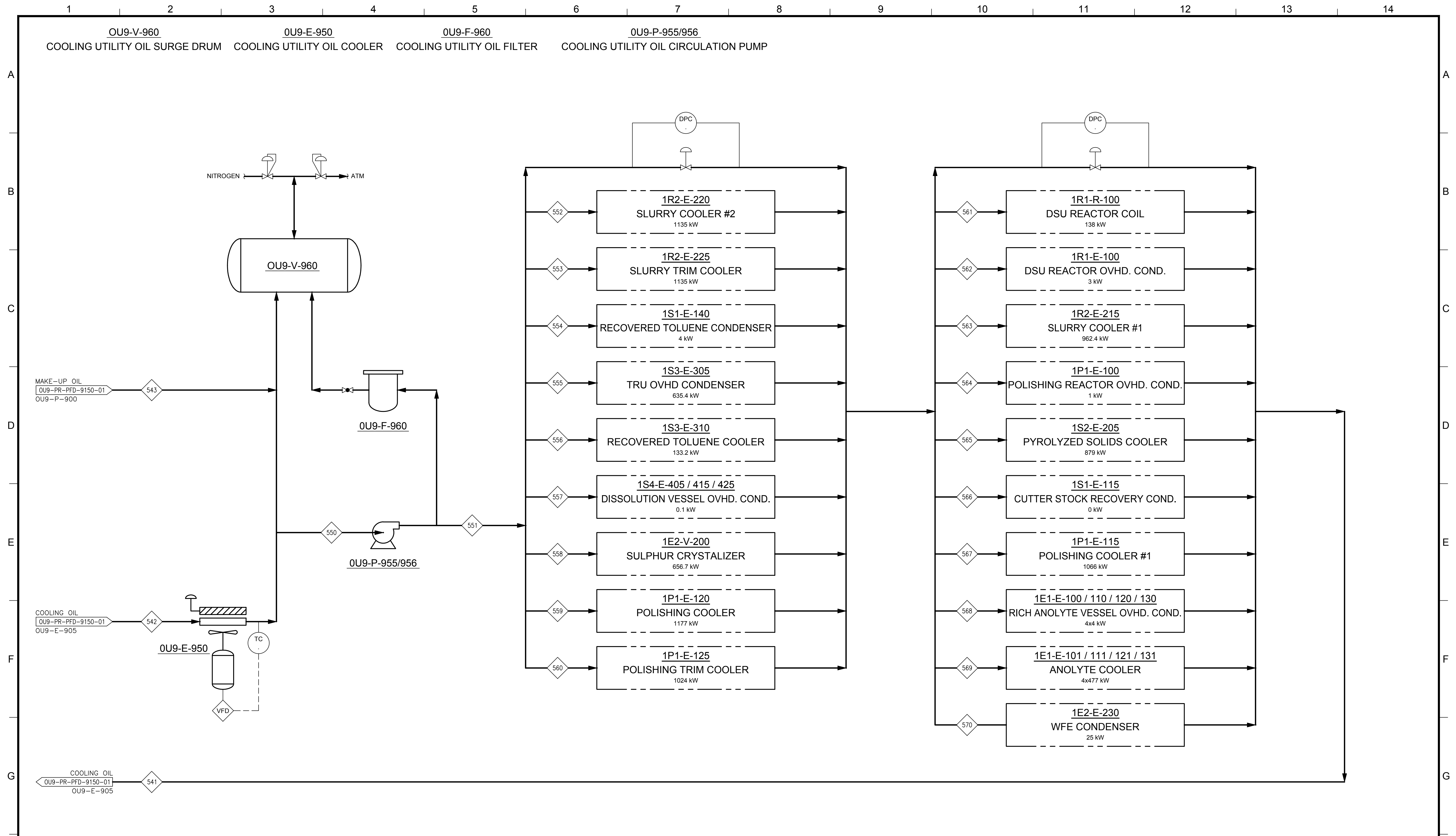
Appendix C - FLD-0U8-PR-SKT-0001 – ORC System #1: Flue Gas Waste Heat Recovery


Appendix D - FLD-0U8-PR-SKT-0002 – ORC System #2: Cooling Oil Exit Waste Heat Recovery

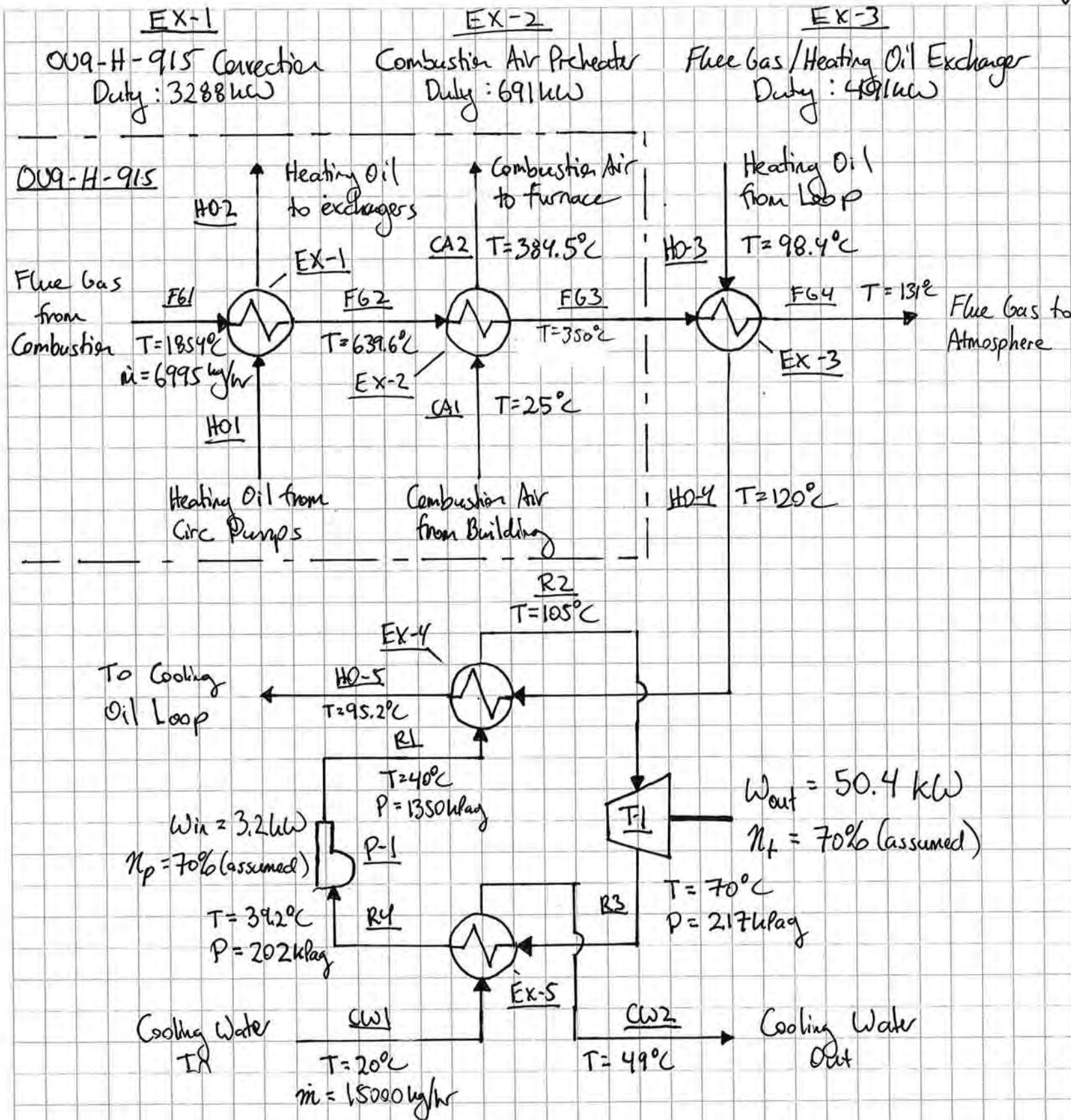
Appendix E - FDU-017-060-01-001 - ORC Waste Heat Calculations



NOTES AND GENERAL INFORMATION				REF DWG NO	REFERENCE DRAWING DESCRIPTION	REV	REV DATE (YYYY-MM-DD)	REVISION DESCRIPTION	BY	CHK'D	APP'D	ENGINEERS AND PERMIT STAMP	<div>CLEANSEAS</div> <div>A FIELD  Upgrading™ PROJECT</div> <div>CLEAN SEAS DEMONSTRATION PROJECT</div> <div>HEATING OIL UTILITY SYSTEM</div> <div>PROCESS FLOW DIAGRAM</div> <div>SCALE: NONE DWG No: FS1-OU9-PR-PFD-9150-01 REV: A</div>			
NOTES: 1. ALL INSTRUMENTS & VALVE TAGS PRECEDED BY ### - UNLESS NOTED OTHERWISE.				-		A	2017-03-24	ISSUED FOR APPROVAL	WD	KC	MEM					
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OU9-H-915

Adiabatic Flame Temperature: 1854°C

Heat Transfer - Convection: 3288 kW

Assumed Boiler Efficiency: 70%

Assumed Air Excess: 15%

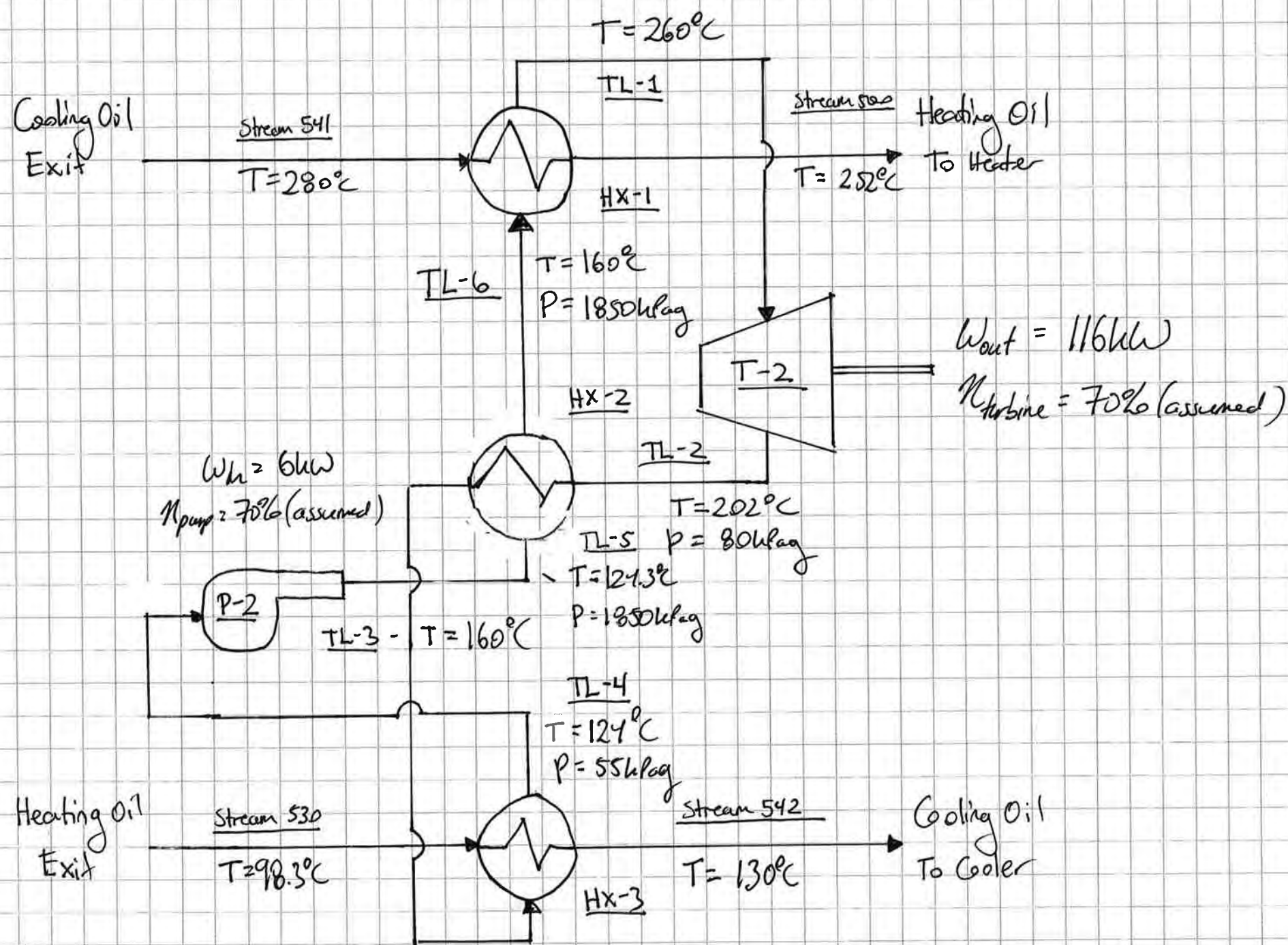
City Flow Rate: 338.2 kg/hr

ORC System

Working Fluid: 1,1,1,3,3-Pentafluoropropane (HFC-245fa)

Mass Flow Rate HFC-245fa: 9200 kg/hr

HX-1 Cooling Oil ORC Evaporator Duty: 850kW
HX-2 Cooling Oil ORC Recuperator Duty: 131kW
HX-3 Cooling Oil ORC Condenser Duty: 740kW
P-2 Cooling Oil ORC Pump Duty: 6kW
T-2 Cooling Oil ORC Turbine Duty: 116kW



ORC System
Working Fluid: Toluene
Mass Flow Rate: 9200 kg/hr

CLIENT: Field Upgrading Ltd.

PROJECT: DSU™ Technology

SUBJECT: ORC Waste Heat Calculations

DISCIPLINE: Process

PAGE: 1 OF 3

ORIGINATOR: Pat Stewart / PS

CHECKER: Ali Farzaneh

ELECTRONIC FILE LOCATION: \\Senfps01\sentio\Projects\Engineering\Field Upgrading\FDU-017-60 2111 Process Engineering\Calculations\FDU-017-060-01-CAL-001\FDU-017-060-01-001 - C

PURPOSE OF CALCULATIONS

1. Determine the flue gas flow rate and adiabatic flame temperature from OU9-H-915 to input into VMG
2. Determine the increase in heater duty and CO2 emissions with an ORC system in place
3. Calculate the efficiency, estimated cost, and payback period of the identified ORC Systems

DESIGN CRITERIA

ASSUMPTIONS AND LIMITATIONS

1. Fuel Gas used is Methane
2. 15% excess air to boiler
3. 100% combustion of methane (No CO, NOx, SOx emissions)
4. Adiabatic Flame Temperature assumed to be the flue gas temperature in the heater
5. VMG used to determine duty of exchangers, process parameters, and output of turbines
6. Boiler, Pump, and Turbine efficiencies all assumed to be 70%
7. Exchange Rate CAD/USD assumed to be 1.33
8. Direct Energy Rate for Oilfield Service used as a basis, averaging historical rates since Jan 2015
9. The installation cost for the ORC is assumed for the unit only. It does not include additional equipment outside of the ORC system

REFERENCES

1. FS1-OU9-PR-PFD-9150-01 Heating Oil Utility System
2. FS1-OU9-PR-PFD-9151-01 Cooling Oil Utility System
3. FLD-OU8-PR-SKT-0001 ORC System #1 - Flue Gas Waste Heat Recovery
4. FLD-OU8-PR-SKT-0002 ORC System #2 - Cooling Oil Exit Waste Heat Recovery
5. VMG Process Simulation: DSU Plant 2500 bpd - Esso VR-Rev9 IFU PS ORC Utility Heater
6. FDU-000-PR-STY-0001_RA WHR Study

SOFTWARE USED (Title and Version)

VMG Process Simulation v10.0

A	DESCRIPTION	PS BY	DATE	CHK	DATE	APP'D	DATE
REV	Issued for Review		23-Mar-17		23-Mar-17		23-Mar-17

CALCULATION RECORD

The electronic form of this document on the Prone Intranet is the latest version. Printed copies are uncontrolled and may not be the latest revision

OU9-H-915 Heating Utility Oil Heater

Assumption 15% excess air

Combustion Reaction: $\text{CH}_4 + 1.15 \times 2(\text{O}_2 + 3.76\text{N}_2) \rightarrow \text{CO}_2 + 2\text{H}_2\text{O} + (2.3 - 2)\text{O}_2 + (3.76 \times 2.20)\text{N}_2$
 $\text{CH}_4 + 2.3\text{O}_2 + 8.648\text{N}_2 \rightarrow \text{CO}_2 + 2\text{H}_2\text{O} + 0.3\text{O}_2 + 8.648\text{N}_2$

Total flue gas mol	11.472
nCO2 mol basis	8.7%
nH2O	17.4%
nO2	1.7%
nN2	72.1%
	100.0%

Fuel mix mol	25.944
nC	3.9%
nH	15.4%
nN	63.8%
nO	17.0%
	100%

Partial Pressure H2O 17.4 Dew Point Temp 56.9 C

No Cooling Oil ORC 2 Used

Heating Output to Oil 3288 kW LHV CH4 50 MJ/kg
 Boiler Efficiency 70% mass flow CH4 338.2 kg/hr
 Heat from Combustion 4697.1 kW Volume Flow 471.7 m3/hr
 Molar Flow 21.08 kmol/hr

Reactants	Stoic mol ratio	Molar Flow (kmol/hr)	Molar Mass (g/mol)	Mass flow (kg/hr)
O2	2.3	48.49	32	1552
N2	8.648	182.34	28	5105
			Total	6657

Products	Stoic mol ratio	Molar Flow (kmol/hr)	Molar Mass (g/mol)	Mass flow (kg/hr)	Mass Flow (t/yr)
CO2	1	21.08	44	928	8127
H2O	2	42.17	18	759	6649
O2	0.3	6.33	32	202	1773
N2	8.648	182.34	28	5105	44724
			Total	6995	61273

Cooling Oil ORC 2 In Service

Heating Output to Oil 3526 kW LHV CH4 50 MJ/kg
 Boiler Efficiency 70% mass flow CH4 362.7 kg/hr
 Heat from Combustion 5037.1 kW Volume Flow 505.8 m3/hr
 Molar Flow 22.61 kmol/hr

Reactants	Stoic mol ratio	Molar Flow (kmol/hr)	Molar Mass (g/mol)	Mass flow (kg/hr)
O2	2.3	52.00	32	1664
N2	8.648	182.34	28	5105
			Total	6770

Products	Stoic mol ratio	Molar Flow (kmol/hr)	MM (g/mol)	Mass flow (kg/hr)	Mass Flow (t/yr)
CO2	1	22.61	44	995	8715
H2O	2	45.22	18	814	7130
O2	0.3	6.78	32	217	1901
N2	8.648	195.54	28	5475	47961
			Total	7501	65708

Increase in CO2 Emissions from ORC 2 7%

Adiabatic Flame Temperature

Assumption Combustion Air Temperature = 25 C

$$0 = -n\text{CH}_4 \cdot \text{HfCH}_4 + n\text{CO}_2(\text{Hf} + \text{dh}) + n\text{H}_2\text{O}(\text{Hf} + \text{dh}) + n\text{O}_2 \cdot \text{dh} + n\text{N}_2 \cdot \text{dh}$$

	h formation	delta h @ 2000K	delta h @ 2200K
CH4	-74873		
CO2	-393522	91439	103562
H2O	-241826	72788	83153
O2		59176	66770
*Unit Costs Retrieved From Quolin, 2013 -		56137	63362
Total		-136933.424	-39320.424

Adiabatic Flame Temp 2127 K 1854 C

ORC System Efficiency Analysis and Cost Analysis

Drawing Source:

Carnot Cycle Efficiency

$$N_{\text{carnot}} = (T_h - T_c) / T_h * 100\%$$

T_h Maximum Working Fluid Temperature
 T_c Rejection Temperature
 N_{carnot} Carnot Efficiency (Maximum, no entropy)

	T_h (K)	T_c (K)	N_{carnot}
ORC System #1	378	323	15%
ORC System #2	533	433	19%

Actual Cycle Efficiency

$$N = (W_t - W_p) / Q_{\text{evapo probe}}$$

W_t Work by Turbine
 W_p Work by Pump
 $Q_{\text{evaporator}}$ Heat Absorbed by evaporator
 N Efficiency of System
 N/N_{carnot} Efficiency as a fraction of N_{carnot}

	W_t (kW)	W_p (kW)	$Q_{\text{evaporator}}$ (kW)	N	N/N_{carnot}
ORC #1	50.4	3.2	562	8%	58%
ORC #2	116	6	850	13%	69%

Estimated Installation Cost - 2500 bbl/d

March 22 CAD/USD Exchange Rate 1.33

	W_t (kW)	Unit Cost (\$USD/kW)	Unit Cost (\$CAD/kW)	Installation Cost (CAD)
ORC #1	50.4	4000	\$5,320	\$268,128
ORC #2	116	2500	\$3,325	\$385,700

Estimated Payback - 2500 bbl/d

Direct Energy Rates for Oilfield - Average since Jan 2015 0.04687 \$/kWh

	kWh	kWh/year	\$/year	Payback (Years)
ORC #1	1132.8	413,472	\$19,378	14
ORC #2	2640	963,600	\$45,161	9

Estimated Installation Cost - 10,000 bbl/d

	W_t (kW)	Unit Cost (\$/kW)	Unit Cost (\$CAD/kW)	Installation Cost (CAD)
ORC #1	201.6	2000	\$2,660	\$536,256
ORC #2	464	1700	\$2,261	\$1,049,104

Estimated Payback - 10,000 bbl/d

	kWh	kWh/year	\$/year	Payback (Years)
ORC #1	4531.2	1,653,888	\$77,512	7
ORC #2	10560	3,854,400	\$180,643	6

3.5 Year Payback Case

	W_t (kW)	Unit Cost (\$/kW)	Unit Cost (\$CAD/kW)	Installation Cost (CAD)
ORC #1	5000	1000	\$1,330	\$6,650,000
ORC #2	5000	1000	\$1,330	\$6,650,000

	kWh	kWh/year	\$/year	Payback (Years)
ORC #1	112500	41,062,500	\$1,924,463	3.5
ORC #2	113684	41,494,737	\$1,944,720	3.4

*Unit Costs Retrieved From Quolin, 2013 - Secion 9.0 (1) in FDU-000-PR-STY-0001_RA



Appendix 7: BLOOM DSU Environmental Report

Environmental Benefits Final Report

For
DSU Technology

Prepared for:
Field Upgrading Limited

Prepared by:
The Bloom Centre for Sustainability

BP 4001-55-002

November 2017
December 2017 – Revision 2.0



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EXECUTIVE SUMMARY

Field Upgrading Limited has demonstrated its DSU™ technology, an innovative sulphur removal technology that uses sodium to selectively remove the components of sour heavy oil feedstocks that reduce its value. Initially, the focus of the project was on bitumen partial upgrade and on marine fuel production from bitumen. Currently, Field Upgrading is focusing on producing marine fuel with low sulfur from several feedstock rather than partially upgraded bitumen for refineries. This is the result of the emerging of new market for low sulphur marine fuel as a result the new Sulphur regulations.

This report was developed by the Bloom Centre for Sustainability (BLOOM) on behalf of Field Upgrading Limited. The purpose of this report is to quantify the environmental benefits of the DSU™ at commercial scale. The environmental benefits to be assessed for this project is reduction of energy use and greenhouse gases (GHG) and air pollutants generated during marine fuel production with sulphur content not exceeding 0.5%. The baseline selected for this project is marine diesel oil (MDO) with sulphur content of 0.5%. The functional unit of the project is bbl of marine residual fuel (MRF) with low S content.

Environmental impact calculations and assumptions are presented in details in the attached excel worksheets. Table S.1 presents technology environmental benefits per functional unit. Tables S.2 and S.3 summarize the technology market roll out environmental benefits.

Table S.1 - Environmental Benefits per Functional Unit

Bitumen Feedstock	CO ₂ e (kg/bbl Marine fuel)		SO _x (kg/bbl Marine fuel)		NO _x (kg/bbl Marine fuel)		PM (kg/bbl Marine fuel)		CO (kg/bbl Marine fuel)		VOC (kg/bbl Marine fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline	151	10%	0.13	8%	0.12	13%	0.02	10%	0.06	12%	0.03	11%
Project	138	6%	0.04	4%	0.16	6%	0.01	6%	0.07	6%	0.02	6%
Reduction from Baseline	13	139%	0.10	11%	-0.04	47%	0.01	22%	-0.01	81%	0.01	25%
VR Blend Feedstock	CO ₂ e (kg/bbl Marine Fuel)		SO _x (kg/bbl Marine Fuel)		NO _x (kg/bbl Marine Fuel)		PM (kg/bbl Marine Fuel)		CO (kg/bbl Marine Fuel)		VOC (kg/bbl Marine Fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline Scenario	69	7%	0.13	7%	0.13	9%	0.02	8%	0.06	9%	0.01	7%
Project	55	5%	0.07	8%	0.16	8%	0.01	10%	0.07	8%	0.03	9%
Reduction from Baseline	14.3	42%	0.06	18%	-0.03	56%	0.00	69%	-0.01	79%	-0.01	20%

Table S.2 – Canadian Market Roll Out Environmental Benefits

Year	New installation	Additional Annual Capacity (bbl)	Cummulative Annual Capacity (bbl)	GHG Reductions in ref. year (kilotonnes/y)	SO _x Reductions in ref. year (tonnes/y)	NO _x Reductions in ref. year (tonnes/y)	PM Reductions in ref. year (tonnes/y)	CO Reductions in ref. year (tonnes/y)	VOCs Reductions in ref. year (tonnes/y)
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	1	625,000	625,000	8	59	-24	5	-7	8
2021	1	1,875,000	2,500,000	32	238	-94	18	-26	34
2022	0	0	2,500,000	32	238	-94	18	-26	34
2023	1	6,250,000	8,750,000	121	627	-298	36	-85	-49
2024	0	0	8,750,000	121	627	-298	36	-85	-49
2025	1	12,500,000	21,250,000	281	1,817	-770	126	-215	120
2026	0	0	21,250,000	281	1,817	-770	126	-215	120
2027	0	0	21,250,000	281	1,817	-770	126	-215	120
2028	0	0	21,250,000	281	1,817	-770	126	-215	120
2029	1	6,250,000	27,500,000	361	2,411	-1,006	172	-280	204



Table S.3 – Rest of the World Market Roll Out Environmental Benefits

Year	New installation	Additional Annual Capacity (bbl)	Cumulative Annual Capacity (bbl)	GHG Reductions in ref. year (kilotonnes/y)	SOx Reductions in ref. year (tonnes/y)	NOx Reductions in ref. year (tonnes/y)	PM Reductions in ref. year (tonnes/y)	CO Reductions in ref. year (tonnes/y)	VOCs Reductions in ref. year (tonnes/y)
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0
2022	1	6,250,000	6,250,000	89	389	-204	17	-59	-82
2023	1	6,250,000	12,500,000	179	778	-408	35	-117	-165
2024	1	6,250,000	18,750,000	268	1,168	-612	52	-176	-247
2025	1	6,250,000	25,000,000	357	1,557	-816	69	-234	-330
2026	1	6,250,000	31,250,000	447	1,946	-1,020	87	-293	-412
2027	0	0	31,250,000	447	1,946	-1,020	87	-293	-412
2028	0	0	31,250,000	447	1,946	-1,020	87	-293	-412
2029	1	6,250,000	37,500,000	536	2,335	-1,224	104	-351	-495



1.0 INTRODUCTION TO SDTC

1.1 SUSTAINABLE DEVELOPMENT TECHNOLOGY CANADA (SDTC)

1.1.1 Role

Sustainable Development Technology Canada (SDTC) is a not-for-profit arms-length foundation created by the Government of Canada that finances and supports the development and demonstration of clean technologies which provide solutions to issues of climate change, clean air, water quality and soil, and which deliver economic, environmental and health benefits to Canadians.

1.1.2 Mission and Mandate

SDTC was established by the Government of Canada in 2001 and commenced operation in November of that year. SDTC's mission is to act as the primary catalyst in building a sustainable development technology infrastructure in Canada. However, SDTC does much more than simply fund groundbreaking technologies – it works closely with an ever-growing network of stakeholders and partners to build the capacity of Canadian clean-technology entrepreneurs, helping them form strategic relationships, formalize their business plans, and build a critical mass of sustainable development capability in Canada.

1.1.3 Bridging the Gap

There are many links in the innovation chain between research and commercialization. Two of the most critical—but traditionally under-supported—links are development and demonstration. These are the critical stages at which technologies exit the laboratory and prove themselves in full-scale, real-world test situations. SDTC bridges the gap in the innovation chain by fast-tracking groundbreaking clean technologies through development and demonstration, in preparation for commercialization. SDTC fosters and encourages innovation and collaboration among private, academic and public-sector partners, and strives to ensure the dispersion of clean technologies in relevant market sectors throughout Canada.

1.1.4 Reducing the Risk

One of SDTC's chief aims is to de-risk clean technologies in a way that will ultimately attract downstream private-sector investment and open up opportunities for commercial success. This is done by employing a stringent due diligence process when selecting technologies to support, and by actively strengthening project consortia—requiring every project to involve representatives from the entire supply chain: researchers, product developers, manufacturers, distributors, retailers and end customers. In all, 80 percent of funded consortia are industry-led.

1.1.5 Building Capacity

By assembling consortia of partners who strengthen one another's go-to-market capabilities, SDTC helps build the capacity for innovation and success of Canada's clean-technology entrepreneurs. Through this process innovators are helped to sharpen their market savvy, increase their ability to identify the economic and environmental strengths of sustainable



development projects, and define the investment potential that their clean technologies ultimately represent to venture capital financiers.

1.1.6 Defining Sustainable Development

Sustainability is about doing all that we do today as societies and economies with three considerations in mind:

- Environmental—ensuring that resources are not consumed faster than they can be replenished;
- Economic—supporting prosperity and growth; and
- Social—respecting the values, culture and human needs of communities.

All of the projects funded by SDTC support these goals.

1.2 SUSTAINABLE DEVELOPMENT BENEFITS REPORTING SYSTEM

Within the SDTC Business Plan and Funding Agreement, SDTC is committed to report the performance and impacts of all SDTC funded projects. The purpose of the Benefits Report is to provide:

- Guidance to project proponents and fund managers to evaluate the GHG claims of SDTC projects; and
- An example to businesses and their associations, the Government of Canada and international community of an approach used in Canada to evaluate GHG mitigation technology projects.

The Sustainable Development Benefits Report (*Benefits Report*) was designed as a practical and cost-effective approach to provide a clear and accurate evaluation of the technical performance and impacts of projects. As well, the Benefits Report offers many benefits to both project proponents and government programs. Companies benefit by establishing credibility, gaining experience and know-how, showing leadership, building competitive advantage, maintaining constructive government and public relations, and developing a network of partners and relationships to be prepared to participate in future climate change initiatives. The Government of Canada benefits in the confidence and knowledge that its investments have real-world results, are fiscally responsible, build capacity in the private sector, and reduce risks associated with climate change and clean air, water and soil.

1.3 OBJECTIVES

Fundamentally, GHG, air, water and soil emission reductions result from a reduction in activity and/or a reduction in emissions intensity (e.g., GHG emissions per unit activity relative to the baseline activity). The general objective of the Benefits Report is to determine the advantages of the technology/project in terms of:

- Emissions reductions per unit (e.g., tonnes of CO₂e mitigated per unit of energy, mass, or activity);
- Annualized emission reductions per unit of technology/project (e.g. tonnes of CO₂e mitigated per unit technology per year); and



- Total emission reductions (e.g., tonnes of CO₂e mitigated) for the SDTC-funded project.

Please note, however, that the Benefits Report itself is not intended to certify or otherwise confirm GHG emission reduction credits.



2.0 PROJECT DOCUMENT OVERVIEW

2.1 BENEFITS REPORT

This Report has been prepared by the BLOOM Centre for Sustainability in collaboration with the SDTC office and the project proponent, Field Upgrading. The BLOOM Centre for Sustainability has been retained by Field Upgrading for this project.

This report has been developed consistent with the Sustainable Development Benefits Reporting System, as provided by the SDTC office. As established by the guidelines, and modified as appropriate based on project-specific circumstances and discussions with the SDTC office and the project proponent, this report documents the following:

- a) Project Overview
- b) Demonstration Project Results
- c) Project and Baseline Emission Source Identification and Selection
- d) Project and Baseline Emissions Quantifications
- e) Project and Market Roll-Out Results
- f) References

This report has been developed based on demonstration results and previous work and information provided by the project proponent.

Accompanying this report are various spreadsheets, which have been used to generate the quantitative environmental impacts results provided in this report:

- An emission calculator spreadsheet.
- A market roll-out summary spreadsheet, including market roll-out absolute emission reduction calculations.

Documentation used in this report is noted in the References section at the end of this report. References for factors, etc. contained solely in the spreadsheets can be found in the spreadsheets.



3.0 PROJECT OVERVIEW

3.1 BACKGROUND

Field Upgrading Limited has contracted the BLOOM Centre for Sustainability (BLOOM) in February 2015, as a third party environmental impact quantification expert to complete the Initial (baseline) environmental impacts report as required by Sustainable Development Technology Canada (SDTC) in order to ensure optimal quality benefits quantification during the project completion phase. BLOOM has developed the report “Initial Environmental Benefits Report for Desulphurization and Upgrading Technology” dated March 2015.

Field Upgrading has completed the project and submitted the following documents to complete the Environmental Benefits Final Report:

- Field Upgrading Limited. SDTC Milestone 1 Report – March 31, 2015
- Field Upgrading Limited. SDTC Milestone 2 Report – September 30, 2016
- Field Upgrading Limited. SDTC Milestone 3 Report – March 31, 2017
- Field Upgrading Limited. SDTC Milestone 4 Report and Final Report – May 30, 2017
- Field Upgrading Limited. Environmental Tables – Excel Spreadsheets FEED M\$EB – November 13, 2017
- Field Upgrading Limited. Environmental Tables – Excel Spreadsheets Bitumen M&EB – November 15, 2017

The report summarizes BLOOM’s assessment of the project and presents the updated environmental impacts quantification and market roll-out.



3.2 PROPOSED PROJECT DESCRIPTION

(Source: Schedule A)

All oil sands bitumen must be upgraded prior to being processed by refineries. Upgrading typically removes the heaviest fractions, removes impurities, and reduces the density and viscosity of the bitumen. Field Upgrading Limited intends to pilot its DSU™ technology, an innovative sulphur removal technology that uses sodium to selectively remove the components of sour heavy oil feedstocks that reduce its value.

The reactivity of sodium allows for the elimination of many conventional upgrader steps by combining sulphur removal, metals precipitation and upgrading in one step; this is estimated to reduce capital costs by 50%, and operating costs by 30% when compared to conventional upgraders. In addition, the modular nature of the DSU facilities allows for better capacity matching with production facilities as well as better cost control, maintenance and uptime.

Field Upgrading will design, build and operate a 10 Bpd pilot facility to provide the necessary data to advance the technology to build a commercial demonstration plant in Fort Saskatchewan, located on Aux Sable's site. The pilot facility will be comprised of four skids: one for the reactor process, a second for the separation processes, a third for electrolytic regeneration, and a final skid containing all utilities. Key partner suppliers include Zeton for the design and fabrication of the skids and Ceramatec with whom Field Upgrading has the exclusive worldwide rights to the DSU™ technology for oil and gas applications (Ceramatec will also perform lab testing and the development of the e-Cell. Dupont and Creative Engineers have been engaged to address safety procedures and standards associated with sodium handling.

3.3 TECHNOLOGY DESCRIPTION

(Source: Contribution Agreement -Schedule A)

DSU™ differs from incumbent technologies by selectively removing the components of oil sands bitumen (or other sour heavy petroleum feedstocks) including sulphur, heavy metals and Total Acid Number (TAN) that reduce its value without reducing volumetric yield typically as a result of dropping out coke and asphaltenes. The key to the process is sodium, a potent reducing agent with a strong affinity for heteroatoms and metals interspersed in the complex heavy oil molecule. Figure 3.1 shows a simplified diagram of the DSU™ process.

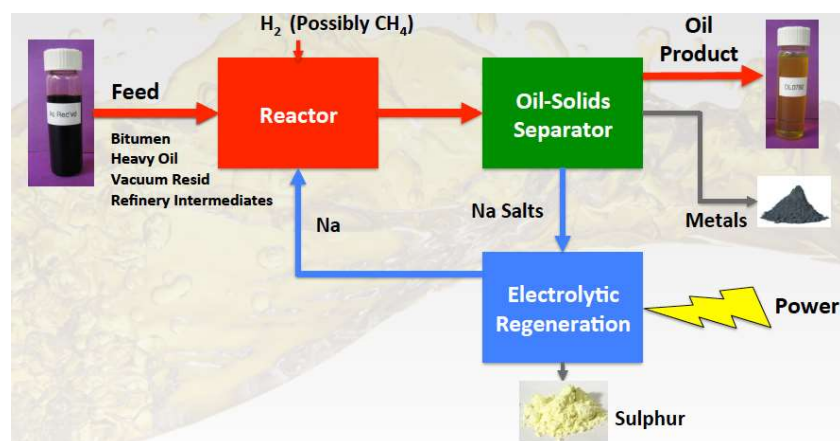
By selectively removing undesirable components, the process forms lower density molecules and breaks some of the larger molecules into smaller molecules. In addition, the DSU™ technology is the only partial upgrading technology that can directly produce a Low Sulphur Fuel Oil for sale into the marine bunker fuel market. The main competing approaches achieve similar quality improvements by dropping out byproducts such as petroleum coke and asphaltenes. Based on bench-test data obtained to date, these approaches generate lower liquid yield (88% - 92%) compared to the DSU™ technology (96% - 100% liquid yield). This means that for similarly priced



end products, alternative approaches to DSU™ would earn ~10% less revenue for each barrel of feedstock.

Conventional upgrading and hydro-treating technologies require large quantities of hydrogen, which results in significant CO₂ emissions and high operating costs.

Figure 3.1: DSU™ Diagram



The proposed process had three general steps:

- Removal of sulphur, nitrogen and metals: Sodium, hydrogen and heavy oil are mixed in a reactor at ~350 °C and pressures up to 1500 PSIG. The sodium preferentially seeks out and eliminates TAN, reduces metals to elemental form and removes sulphur. Hydrogen attaches to the newly exposed ends of the bitumen molecules. The resulting DSU™ product is partially upgraded with virtually no TAN and very low metals such as vanadium and nickel and sulphur.
- Separation of solids: The product solids, which include sodium sulfide, metals and a small amount of residual carbon, are separated from the oil. The sodium salts (primarily sodium sulfide) are selectively dissolved in a solvent, allowing the remaining metals and residual carbon to be recovered. The metals are recovered in pure elemental form and could be sold as a by-product.
- Regeneration of sodium using a patented ceramic transport membrane reactor: The dissolved sodium salts are introduced to a bank of electrolytic cells. When electricity is applied, elemental sodium is extracted through the membrane and recycled to the process. The ability to recover >90% of the sodium is the key economic factor that makes this technology unique. The remaining product is elemental sulphur, which may be sold as a by-product.



3.4 PROPOSED PROJECT OBJECTIVES

(Adopted from Contribution Agreement- Schedule A)

The initial objectives of the project were to:

- Design build and operate a continuous larger scale pilot facility that will validate the DSU™ technology in a continuous 100 plus hour operation using representative feedstocks.
- Operate the pilot plant through commissioning, optimization and campaign-style test runs for up to 8 months with zero Health, Safety or Environmental incidents demonstrating safe and reliable operations of the DSU™ process.
- Complete the testing necessary to collect the detailed engineering data required to design and build a modular 1,000 Bpd commercial demonstration plant.
- Complete economics and design to confirm the economic and environmental advantages of the DSU™ process for target markets estimated at the outset of the project.

Testing and objectives completed during the project are summarized in the Section below.

3.5 PROJECT RESULT

3.5.1 Milestone 1 – Complete Design of System Components

(Source: Field Upgrading Limited. SDTC Milestone 1 Report – March 31, 2015)

The milestone started in November 28, 2014 and was completed January 31, 2015. During this period, Field Upgrading has finalized designs for the reactor, solid separation, and eCell module skids. The following were completed during this milestone:

- Testing at external lab verified that condensate can be used as a wash rather than toluene was completed.
- Lab work at Ceramtec confirmed pyrolysis of the solids is a sufficient firewall for the ecells.
- Testing Evodos' centrifuge confirmed its ability to separate Na₂S.
- Lab-scale eCell (V0) achieved sulphur dropout with selected solvent after two months of testing.
- Thirty different variety of feedstocks including asphaltenes were tested and results optimization are achieved after three runs.

3.5.2 Milestone 2 – DSU Pilot Plant

The second milestone was completed December 31, 2015 and the following were delivered:

- Installation, commissioning of reactor skid and new micro-pilot eCell skid, and partial commissioning of solid separation skid were completed.



- Reducing the residual sodium in the DSU final product to **below 100ppm to meet the marine fuel ISO 8217 specification** was met using a unique process.
- Successfully testing the process on a Chinese-supplied Venezuelan Vac Resid with 4% S content achieving a final product with **only 0.1% S and a 98% yield**.

3.5.3 Milestone 3 – Pilot Plant Commissioning, Testing and Validation

During this milestone that ended in September 2016, two feedstocks, 2% S vacuum residue blend and 5% S bitumen, were tested by the pilot and samples were sent to Ceramtec laboratory to be tested for comparison. The pilot completed over 55 runs with bitumen as feedstock. Table 3.1 summarizes the result. Although the results showed that the pilot has similar S reduction to the laboratory scale process, the pilot was not able to fully separate the resulting solids (Na₂S). A third feedstock, a representative of the typical low value feedstock for commercial plant, will be tested during the last milestone. Table 3.2 summarizes full range properties comparison between DSU™ product from pilot and laboratory scales for Vacuum residue blend as feedstock

Table 3.1 – Summary Results from Lab and Pilot for Two Feedstocks

Variable	Feed 1	Feed 2
Type of feed	Vacuum residue blend	Bitumen
Sulphur content (%)	2%	5%
Reactor size tested	10 bpd	10 bpd
Laboratory S content result (%)	0.1%	0.5%
Pilot S content result (%)	0.1%	0.5%
Comments	Pilot does not retain light ends in the product thus a representative blended product was prepared for comparison	Completed 55 runs Pilot is unable to fully separate solids

Table 3.2 - DSU™ Product Pilot Scale versus Laboratory Scale

Properties	Lab Scale		Pilot Scale	
	VR- blend	DSU™ Product	VR-blend	DSU™ Product
Product Yield (vol %)	-	97	-	>96
API Gravity	12.4	19.0	14.5	14.8
Sulphur (wt%)	2.1	0.06	1.8	0.17
Carbon (wt%)	86.2	85.7	86.8	85.9
Nitrogen (wt%)	0.6	0.4	0.4	0.3
Hydrogen (wt%)	10.4	11.2	10.7	11.1
Viscosity @ 50°C (cSt)	807	235	253	234
Vanadium (wppm)	86	1	88	3
Nickel (wppm)	35	1	43	4
Na Residual (wppm)	55	45	33	N/A



3.5.4 Milestone 4 – Update Technical, Economic Models and Commercialization Plan

Milestone 4 was completed May 30, 2017. The following activities took place during the last milestone:

- Four different feedstocks were successfully processed. Three of the feeds are local Alberta product - LC Finer or HOS bottoms from the nearby Shell upgrader, ESSO Strathcona Refinery's vacuum residue and Cenovus bitumen.
- Pilot testing to gather the design data for the reactor scale-up. The following were confirmed:
 - Reaction kinetics of the sodium-sulphur reaction proceed by a zero-order mechanism
 - Feedstocks with a sulphur content up to 5.1% by wt have successfully been desulphurized to at least 0.5% S in a 6-minute residence time;
 - Optimal reaction operating conditions of 350°C and 5,200 kPa (660°F and 750 psig);
 - Continuous operation was confirmed for extended periods.
- Testing an alternative separation process in the latter part of 2016 that improved the solids separation and will reduce the size and number of vessels for a commercial plant.
- Testing low cost additive that will reduce the residual sodium concentration in the DSU™ product to meet the marine specification of less than 100ppm.
- Confirming eCell scale-up by testing a 4 membrane tall scaffold configuration.
- Continuing to look for alternative solvents to boost eCell performance to reduce the number of eCell modules and thus capital.
- Starting the design basis memorandum or feasibility study on the design of the modular 2500 Bpd demonstration project. This project is named CLEAN SEAS™ to reflect the focus to produce value-added direct-to-ship low sulphur marine fuel.
- Running 13 separate runs and 500 hours of operation on the reactor in 2016 plus another 700 hours in the first quarter of 2017, though the process continued to have plugging problems especially during the last run with the Shell feedstock. However, Field Upgrading believes this may be a function of the small piping in the pilot plant and will not plague us commercially with a larger plant.
- Completing a number of lab scale eCell tests using Na₂S solids made both in the lab and the pilot with results that match the eCell target performance criteria of 65mA/cm². However, there was not enough Na₂S solids in the pilot to run long enough to fully confirm meeting the target and to understand the long term impacts to eCell operation.
- The key success criteria were met as described in Table 3.3.

Table 3.3 - Technology Key Success Criteria

Metric	Success Criteria		
	Minimum	Target	Actual Results
e-Cells	sodium recovery ~95%	sodium recovery ~99% Cell voltage ~4V Current density ~65mA/sqcm	99% as all sodium in the anolyte is recovered. Losses occur earlier in the solids separation process.



Metric	Success Criteria													
	Minimum	Target	Actual Results											
			Current density of 65 mA/sq cm at 3.5 V have been repeatedly achieved. At 4V results at 80 mA/sqcm.											
Capital Intensity (AB)		<\$30,000/Bpd of nameplate capacity	\$25,000-\$30,000/BPD USD is still the range depending on the contingency applied.											
Product Specification	Residual Sodium <350ppm	Residual Sodium <100ppm for the marine industry to meet ISO 8217 2010 RMG 380 Specification	The polishing process consistently removed residual sodium to <100ppm											
	Product from the pilot meets the expected results shown below													
	<table><tr><th>Property</th><th>Expected Product Results</th></tr><tr><td>Product Yield, LV%</td><td>95 – 100%</td></tr><tr><td>API Gravity</td><td>+1-2 API/wt% of sulphur</td></tr><tr><td>Sulphur, wt%</td><td>>92% removal, meet marine specification of 0.5 %S for marine fuel</td></tr><tr><td>TAN, mg KOH/g</td><td>>99% removal</td></tr><tr><td>Ni+V, wppm</td><td>>98% removal</td></tr></table>			Property	Expected Product Results	Product Yield, LV%	95 – 100%	API Gravity	+1-2 API/wt% of sulphur	Sulphur, wt%	>92% removal, meet marine specification of 0.5 %S for marine fuel	TAN, mg KOH/g	>99% removal	Ni+V, wppm
Property	Expected Product Results													
Product Yield, LV%	95 – 100%													
API Gravity	+1-2 API/wt% of sulphur													
Sulphur, wt%	>92% removal, meet marine specification of 0.5 %S for marine fuel													
TAN, mg KOH/g	>99% removal													
Ni+V, wppm	>98% removal													

3.5.5 Demo Project

The pilot plant did not run continuously and only for certain test campaigns. The operation time was less than 50%. Field Upgrading was not able to provide activity data from the pilot demo for the quantification, thus the demonstration environmental impact quantification was not completed.

Estimations for the activity data of the full scale plant (2500 bpd) were provided by Field Upgrading and were applied to quantify project environmental benefits and market roll out estimation.

3.5.6 Project Final Outcomes

Field Upgrading has reported the following as the final outcomes of the project:

- Scaled up the DSU™ technology from the lab to the pilot, building a 10 bpd pilot facility that has been operating for over a year.
- Operated the pilot plant without incident during the project period.
- Four different feedstocks have been processed into a saleable DSU™ product. These feedstocks represent a range of quality we will likely process in a commercial operation.
- Reducing the reactor pressure from 1400 psi down to 750psi. This will greatly improve the capital cost and expand the number of potential vendors to fabricate the reactor.
- Confirmed scaleup of the Nasicon membrane and have commenced the design for a commercial style prototype eCell that we will test in mid 2017.
- Started the engineering for a 2500 Bpd commercial demonstration plant based on data gathered at the pilot.



- Developed and filed patents on new intellectual property related to the solid separation process and removal of residual sodium.

Initially for this project there were two project scenarios, partial upgrading of bitumen for refineries and bunker fuel from bitumen. However, Field Upgrading is planning to focus on producing marine fuel with low sulfur rather than partially update bitumen for refineries. As a result, this report will focus only on the marine fuel with low Sulphur.

3.6 ENVIRONMENTAL BENEFITS

The proposed environmental benefits of the technology included either:

- Reducing energy use and greenhouse gases and air pollutants generated during bitumen upgrading and refining by:
 - increasing product yield, and
 - reducing hydrogen required in conventional upgrading process.
- Reducing energy use and GHG and air pollutants generated during marine fuel production.

For this final report, the focus will be on marine fuel production and the benefit will be:

- Reducing energy use and GHG and air pollutants generated during marine fuel production.

3.7 REVISED PROJECT FUNCTIONS AND FUNCTIONAL UNIT

The project functions and functional units are based on the environmental benefits and objectives of the project discussed in the previous subsection. The main function for the project is the production of marine fuel (bunker fuel) with low S content. The functional unit of the project is bbl of marine residual fuel (MRF) with low S content. The functional unit will provide a quantitative reference to which the project GHG and AP emissions and energy inputs and outputs can be related.



4.0 IDENTIFICATION AND SELECTION OF ELEMENTS ATTRIBUTABLE TO THE PROJECT

4.1 PROCEDURE FOR IDENTIFYING ELEMENTS AND BOUNDARIES

As per System of Measurement and Reporting for Technologies protocol (SMART), the project and baseline boundaries and elements are identified using the following process:

1. Identify the elements for the system (i.e. those directly controlled or owned in the project), including the related (i.e., those elements that are related to the project by energy or material flows) and affected elements (i.e. those elements that cause changes in markets or activity outside the project boundary that are not connected to the project through material or energy flows);
2. Categorize the elements into owned or controlled, and related and affected elements. In accordance with good practice guidelines, elements affected by the project are included within the assessment boundary;
3. Define system boundaries; and
4. Determine if elements are in scope by assessing relevance, significance, and practicality.

4.2 PROJECT ELEMENTS AND BOUNDARIES

In order to determine boundaries and identify the elements attributable to the project and baseline, the procedure outlined above was applied. The boundaries for project will be from well to DSU™ exit gate.

Figure 4.1 provides the flow diagrams of the project scenario. Table 4.1 provides identification of all project elements.

Figure 4.1 – Project Flow Diagram

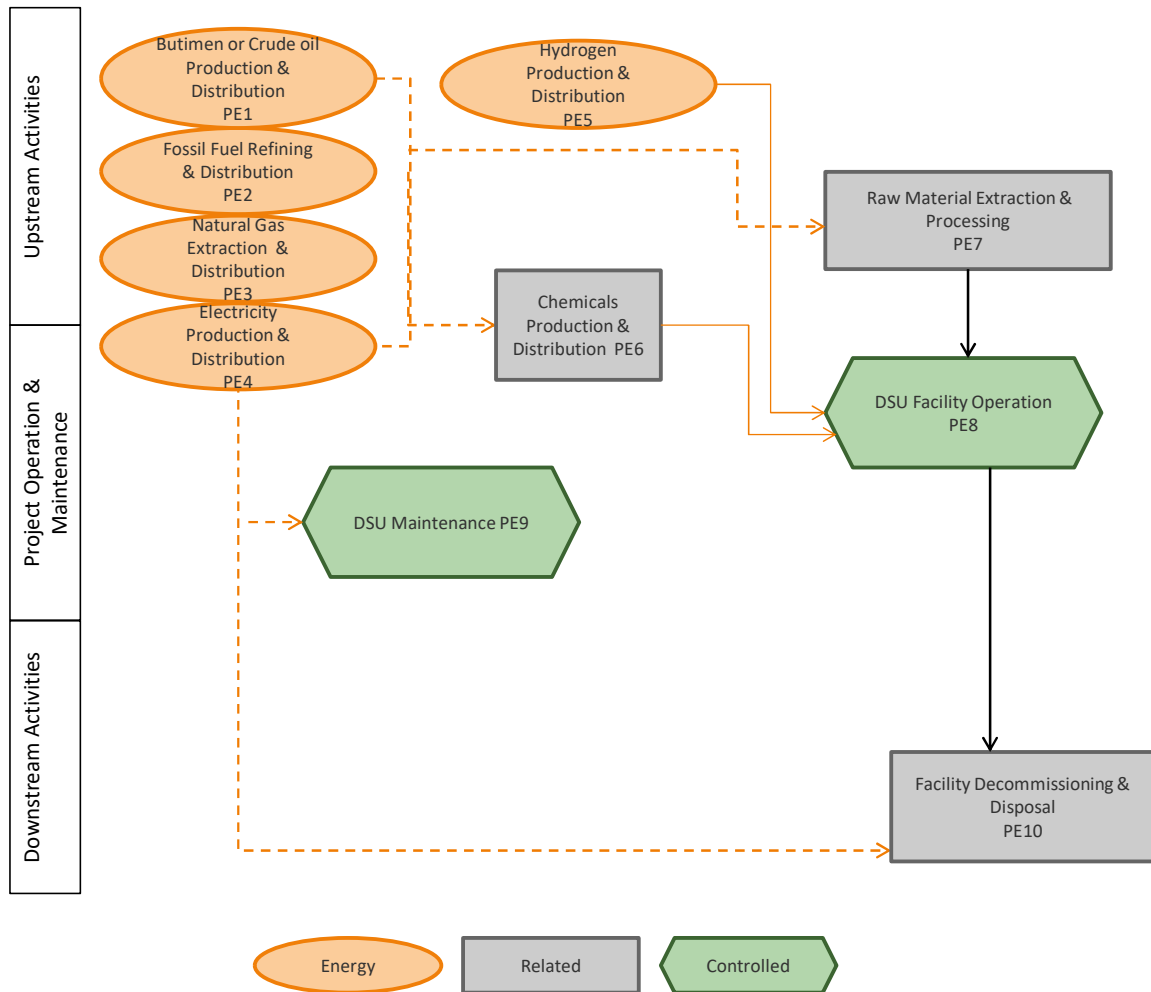




Table 4.1 – Project Elements Identification

Project Elements	Element Name	Element Description	Inputs	Outputs
PE1 Related	Bitumen or Crude Oil Extraction & transportation	Describes the activities involved in bitumen extraction and transportation	Energy Water	GHG AP Bitumen or CO
PE2 Related	Fossil fuel refining and distribution	Describes the activities involved in the production and distribution of transportation fuel	Crude oil Energy Water	Transportation fuel GHG AP By-products Wastewater Waste
PE3 Related	Natural gas production & distribution	Describes the activities involved in the production and distribution of natural gas	Raw material Fuel for energy	Natural gas GHG AP
PE4 Affected	Electricity production & distribution	Describes the activities involved in the production, transmission and distribution of electricity that will be used.	Fuel (renewable, nuclear and fossil fuels)	Electricity GHG AP
PE5 Related	Hydrogen production & distribution	Includes emissions from the extraction, refining raw materials, & manufacturing the system components including batteries	Natural gas Water	GHG AP H ₂
PE6 Related	Chemicals production & distribution	Includes all emissions from production of chemicals	Energy Raw material	GHG AP Chemicals Waste
PE7 Related	DSU™ raw material extraction, distribution & processing	Includes all emissions from extraction, transportation and processing	Fossil fuel Raw material	GHG AP Waste DSU™ process

Project Elements	Element Name	Element Description	Inputs	Outputs
PE8 Controlled	DSU™ operation	Includes energy and chemicals required for the process	Energy Hydrogen Dilbit NaOH Sodium Polar solvent	GHG AP Fuel gas DSU product Sulphur Solids Diluent (condensate)
PE9 Controlled	DSU™ process maintenance	Includes energy and material required during maintenance	Material Energy	GHG AP Waste Recyclable material
PE10 Related	DSU™ process decommissioning	Includes energy and material required for decommissioning	DSU™ facility	GHG AP Waste Recyclable material



5.0 BASELINE SELECTION AND JUSTIFICATION

5.1 BACKGROUND

One of the critical points that must be addressed is the determination of impact that can be attributed to the implementation of a particular project. In order to conduct project impact quantification, a credible baseline must be established. Without a credible baseline or benchmark, accurate estimations of environmental benefits cannot be attributed to a particular project. The baseline should be the best case scenario that would have occurred in the absence of the project and is used to estimate the environmental impacts/benefits of the project.

The approach used to establish the baseline follows current GHG good practice guidance including:

- ISO 14064: Greenhouse Gases – Part 2: Specification for the quantification, monitoring and reporting of project emissions and removals.
- WRI-WBCSD. 2005. The GHG Protocol for Project Accounting. Washington, DC: World Resources Institute.
- TEAM. 2002. Systems of Measurements and Reporting for Technologies (SMART).

Good practice guidance suggests developing a number of alternative baselines scenarios and assessing these against a variety of implementation barriers. Potential scenarios are developed considering project objectives and design, data availability and limitations, and temporal, economic and technical conditions.

In assessing the baseline, the following were assumed:

- The DSU™ process is capable of upgrading different feedstocks such as bitumen and vacuum residue blend by removing Sulphur, TAN and metals.
- For this report bitumen as a feedstock will be considered one of the major feedstock to be processed by DSU™, as it was the initial target feedstock. Vacuum residue blend will be added as a potential feedstock.

5.2 BASELINE SELECTION AND JUSTIFICATION

The new focus of the DSU™ process is the production of HFO or marine fuel bunker with S % that meets the International Maritime Organization (IMO). IMO on October 27, 2016 announced it was going ahead with a global sulfur cap of 0.5% on marine fuels starting from January 1, 2020¹.

As a result, the initial baselines have been revised to meet the revised focus.

Fuel types used in marine transportation differ from most transportation fuels. Marine bunker fuels are either residual fuels, also known as heavy residual fuel (HFO) or intermediate fuel oil (IFO). Substitutes for residual fuels are either marine diesel oil (MDO) and marine gas oil (MGO). Residual fuels are preferred if ship engines can accommodate its poorer quality, unless there are other reasons such as environmental compliance to use more expensive fuels. Of the two strokes engine, 95% use HFO and 5% use MDO while 70% of the four stroke engines are powered by HFO,

with remainder are burning either MDO or MGO. MDO and MGO have a mean sulphur content less than 0.5% Sulphur, 0.38 and 0.35% respectively, while IFO 380 and 180 have a mean Sulphur content of 2.4 and 2.6% respectively². MDO with sulphur content that meets the new regulations was selected as the baseline.

5.3 BASELINE

Based on the procedure defined earlier and given project objectives, Figure 5.1 provides the flow diagram of the baseline scenario. Boundaries for baseline are similar to the boundaries identified to the project in Section 4. Table 5.1 defines the elements for the baseline scenarios.

Figure 5.1 – Baseline Flow Diagram

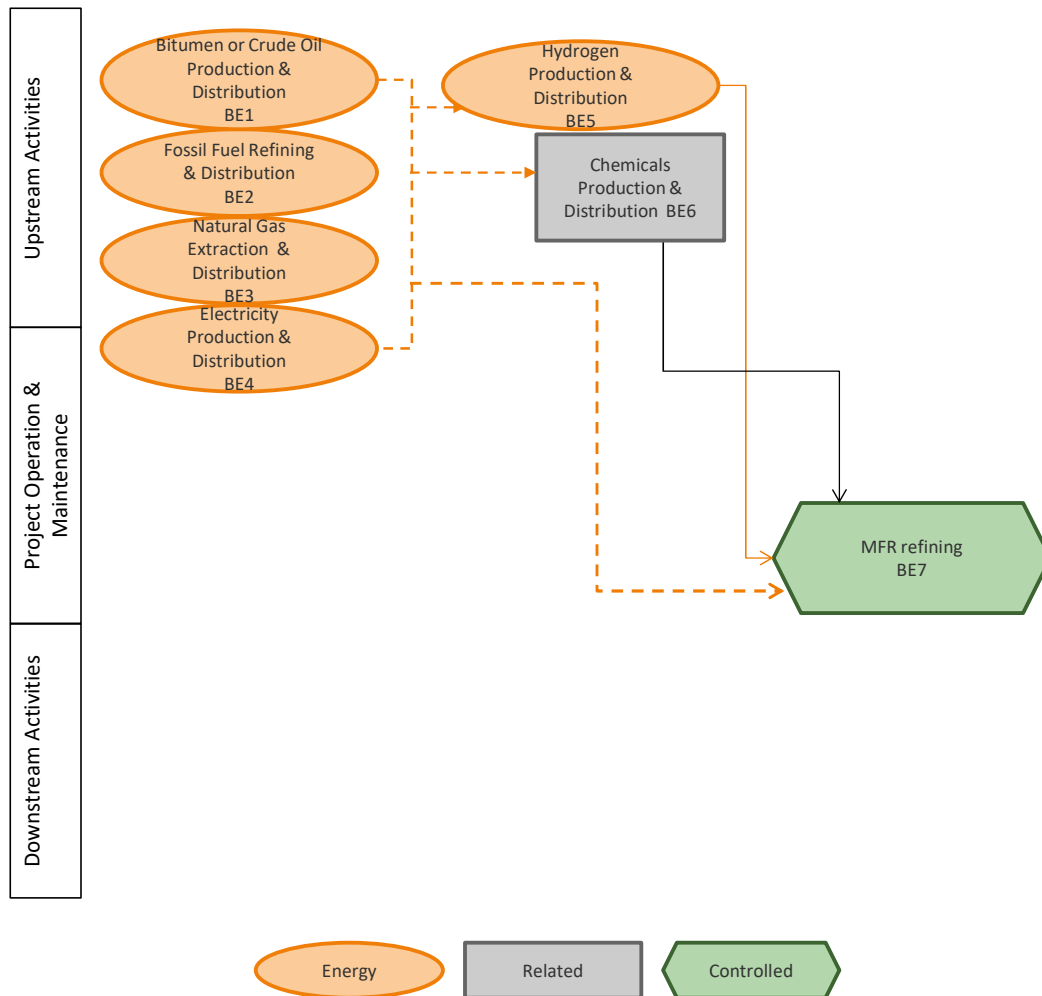


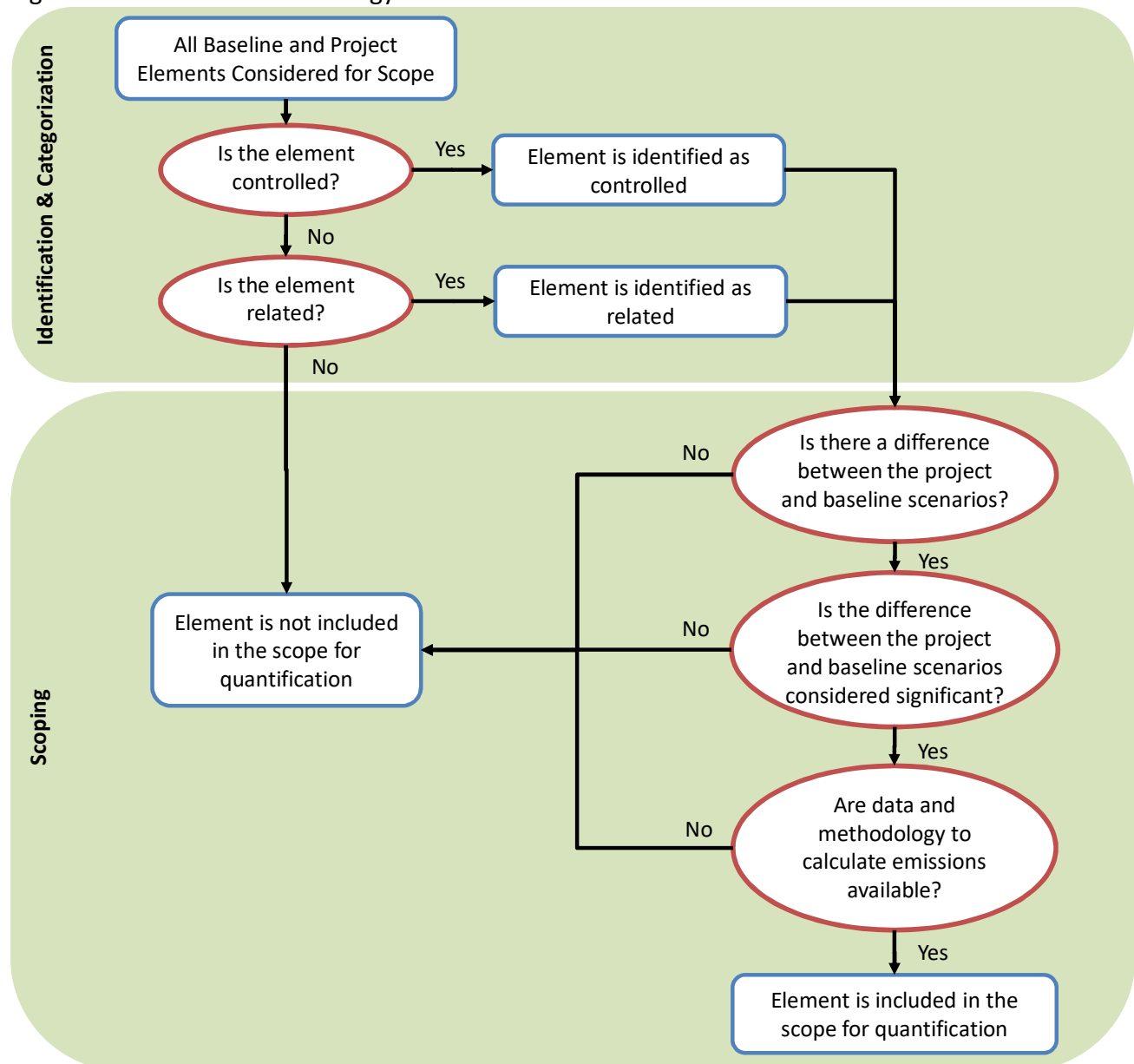
Table 5.1 – Baseline Elements Identification

Baseline Elements	Element Name	Element Description	Inputs	Outputs
BE1	Bitumen Oil or Crude oil Extraction & transportation	Describes the activities involved in bitumen extraction	Energy Water	GHG AP Bitumen or CO
BE2	Fossil fuel refining and distribution	Describes the activities involved in the production and distribution of transportation fuel	Crude oil Energy Water	Transportation fuel GHG AP By-products Wastewater Waste
BE3	Natural gas production & distribution	Describes the activities involved in the production and distribution of natural gas	Raw material Fuel for energy	Natural gas GHG AP
BE4	Electricity production & distribution	Describes the activities involved in the production, transmission and distribution of electricity that will be used.	Fuel (renewable, nuclear and fossil fuels)	Electricity GHG AP
BE5	Hydrogen production & distribution	Includes emissions from the extraction, refining raw materials, & manufacturing the system components including batteries	Natural gas Water	GHG AP H ₂
BE6	Diluents/chemicals production & distribution	Includes all emissions from production and distribution of diluents (condensate or naphtha)	Energy Raw material	GHG AP Diluents
BE7	Marine fuel refining (MFR)	Includes energy and chemicals required for refining bitumen or crude oil to marine residual fuel	Energy Fuel feedstock	GHG AP Marine fuel By-products

6.0 PROJECT SCOPE

All elements identified earlier are either directly or indirectly related to the project or the baseline. In order to determine whether these elements should be included in the scope of the project and would be part of the environmental impacts quantification, the methodology presented in Figure 6.1 was followed.

Figure 6.1 – General Methodology for Element Selection





6.1 SELECTION OF ELEMENTS FOR PROJECT AND BASELINE SCENARIOS

For the baseline scenario that has been identified and justified, the following table has been created to demonstrate that:

- each significant project element has a corresponding baseline element;
- upstream project elements correspond to upstream baseline elements; and
- downstream project elements correspond to downstream baseline elements.

Table 6.1 - Comparison of Project Elements with Baseline Elements

Project 2		Baseline 2	
Element Identifier	Element Name	Element Identifier	Element Name
PE1	Bitumen or crude oil extraction & transportation	BE1	Bitumen or crude oil extraction & transportation
PE2	Fossil fuel refining and distribution	BE2	Fossil fuel refining and distribution
PE3	Natural gas production & distribution	BE3	Natural gas production & distribution
PE4	Electricity production & distribution	BE4	Electricity production & distribution
PE5	Hydrogen production & distribution	BE5	Hydrogen production & distribution
PE6	Chemicals production & distribution	BE6	Diluent/chemicals production & distribution
PE7	DSU™ raw material extraction, distribution & processing	Not Applicable (NA)	
PE8	DSU™ operation	BE7	MFR refinery operation
PE9	DSU™ process maintenance	NA	
PE10	DSU™ process decommissioning	NA	

6.2 ELEMENTS IN THE SCOPE OF THE PROJECT

The scope of the project for GHG quantification included the elements that are relevant, different from the baseline, and have available quantification methodologies for the GHG emission reductions. On this basis, an assessment was undertaken, resulting in a number of elements being included. Project elements highlighted in Table 6.2 are in the scope of the study. Corresponding baseline elements were included in the GHG emission quantification for the baseline scenario. Table 6.3 summarize the baseline elements in the scope of the quantification.

Similar methodology was used to identify the scope for AP quantification. The project scope for AP calculation is similar to the scope for GHG calculation. The APs that were considered in the quantification are SO_x, NO_x, TPM, CO and VOC.

Table 6.2 – Project Elements Included in the Scope

Project elements identifier	Element name	Type of GHG & AP	Change from baseline to project?	Materially significant to direct GHG's ^a & AP?	Data and Quantification Methodology Availability	Included in scope
PE1	Bitumen or crude oil extraction & transportation	Source – Energy production	Yes	Yes	Yes	YES
PE2	Fossil fuel refining and distribution	Source – Energy production	Yes	Yes	Yes	YES
PE3	Natural gas Extraction & transportation	Source – Energy production	Yes	Yes	Yes	YES
PE4	Electricity production & distribution	Source – Energy production	Yes	Yes	Yes	YES^b
PE5	Hydrogen production & distribution	Source - fuel consumption	Yes	Yes	Yes	YES
PE6	Chemicals production & distribution	Source- Industrial and fuel consumption	Yes	Yes	Yes	YES
PE7	DSU™ raw material extraction, distribution & processing	Source- Industrial and fuel consumption	Yes	Yes	No	NO
PE8	DSU™ operation	Source- Industrial and fuel consumption	Yes	Yes	Yes	YES

^a Considered insignificant and was excluded when assumed less than 5% of the GHG or AP emissions from the project

^b Electricity assumed from Cogen on site for project and data aggregated for baseline

Project elements identifier	Element name	Type of GHG & AP	Change from baseline to project?	Materially significant to direct GHG's ^a & AP?	Data and Quantification Methodology Availability	Included in scope
PE9	DSU™ process maintenance	Source - fuel consumption	Yes	Yes	No	NO
P210	DSU™ process decommissioning	Source - fuel consumption	Yes	No	No	NO

Table 6.3 - Elements Included in the Scope

Baseline elements identifier	Element name	Type of GHG & AP	Change from baseline to project?	Materially significant to direct GHG's ^c & AP?	Data and Quantification Methodology Availability	Included in scope
BE1	Bitumen or crude oil extraction & transportation	Source – Energy production	Yes	Yes	Yes	YES
BE2	Fossil fuel refining and distribution	Source – Energy production	Yes	Yes	Yes	YES
BE3	Natural gas Extraction & transportation	Source – Energy production	Yes	Yes	Yes	YES
BE4	Electricity production & distribution	Source – Energy production	Yes	Yes	Yes	YES
BE5	Hydrogen production & distribution	Source - fuel consumption	Yes	Yes	Yes	YES
BE6	Chemicals production & distribution	Source- Industrial and fuel consumption	Yes	Yes	Yes	YES

^c Considered insignificant and was excluded when assumed less than 5% of the GHG or AP emissions from the project



Baseline elements identifier	Element name	Type of GHG & AP	Change from baseline to project?	Materially significant to direct GHG's ^c & AP?	Data and Quantification Methodology Availability	Included in scope
BE7	MRF refining	Source- Industrial and fuel consumption	Yes	Yes	Yes	YES



7.0 ENVIRONMENTAL IMPACT QUANTIFICATION

7.1 ACTIVITY DATA

The following were considered when preparing the environmental quantification worksheets:

- Feedstock with S content ranges 0.5-4% could be used to produce low S marine fuel by DSU™.
- Although Field Upgrading has tested several feedstock, for this quantification bitumen and vacuum residue blend were considered as feedstocks.
- Sulphur content in fuel is to be at most 0.5%.
- DMB (Global), marine diesel oil that is characteristics of all DMB sold globally was considered the baseline final product. The range of S content is 0.05-3.15% with mean at 0.350%. Note we opted not to select DMB 0.1% S as baseline since the DSU™ process is generating marine fuel with 0.5% S content.
- DSU™ transportation as marine fuel bunker to terminal was assumed equal to marine fuel transportation from refinery to terminal.
- Coke from the bitumen upgrader is assumed to be stored and not used as a fuel.

7.2 PROJECT ACTIVITY DATA

For the initial environmental impact report a 25,000 barrel of bitumen per day was assumed for the quantification, inputs, outputs and mass and energy balance as reported in Schedules A and F of the Contribution Agreement were applied. All activity data in the initial report have been revised in this final report.

The focus of the process has been revised and Field Upgrading is considering only marine fuel as a product from the process. Several feedstocks have been tested to generated MRF with low S content from the DSU™. The process activity data estimates were provided by Field Upgrading. It should be noted that BLOOM can't assess the revised activity data as there were insufficient data from the demonstration project that can be used for evaluation. All project activity data are available in the Excel spreadsheets

7.3 BASELINE ACTIVITY DATA

For the baseline, the activity data was based on GREET (2016) for bitumen feedstock and default emission factors from EERA (2008)³ for refining residual oil.

It should be noted that most marine fuel LCA provide aggregated data from well to hull which makes it difficult to determine the portion of the process that can be compared to the DSU™ process.



7.4 GHG EMISSIONS

All default GHG emissions factors applied for the quantification are reported in the Excel spreadsheets.

7.5 AP EMISSIONS

All default emissions applied for the quantification are reported in the Excel sheets.

7.6 MARKET ROLL OUT DATA

Field Upgrading has provided revised market roll out for DSU product and MFR in November 2017 based on their revised market analysis. The revised numbers were applied for market roll out environmental benefit estimates.

7.7 UNCERTAINTY ANALYSIS

Sources of uncertainty that were included in quantification of emissions are:

- activity data uncertainty: uncertainty in the basic data, this includes but not limited to data adequacy, correctness and completeness; and
- model uncertainty or emission factor uncertainty is the uncertainty associated with the quantification methodology.

To calculate the uncertainty of emission estimate of each source the following equation was used:

$$u = \pm \sqrt{a^2 + b^2}$$

Where:

u = overall percent uncertainty for a source;

a = percent uncertainty associated with parameter A (e.g. EF);

b = percent uncertainty associated with parameter B (e.g. activity data)

To use the above mentioned equation the following are assumed:

- uncertainties follow a normal distribution

To calculate the combined uncertainty of the entire set of emission estimates the following equation can be used:

$$U = \pm \frac{\sqrt{\sum G_i^2 u_i^2}}{G}$$

Where:

U = overall percent uncertainty of total GHG or air pollutant estimates;

G_i = GHG or air pollutant estimates from source i ;

u_i = overall percent uncertainty for GHG or air pollutant estimates from source category i ;



G = total GHG or air pollutants estimates from all sources

7.8 UNCERTAINTY APPROACH AND ASSUMPTIONS

Based on our experience and several case studies, the following approach was established for assigning uncertainties to the activity data and EF:

1. If uncertainty levels were assigned with EF at the source, the uncertainty assigned was used.
2. Uncertainty associated with activity data based on actual measurement was assigned an uncertainty value of 1%.
3. Uncertainty associated with the activity level based on engineering calculations was assigned an uncertainty value of 5%.
4. Uncertainty associated with activity data based on previous empirical data and professional judgment was assigned an uncertainty value of 10%.
5. Uncertainty associated with EF based on the actual emission measured or monitored on site was assigned an uncertainty value of 5%.
6. Uncertainty associated with EF based on the use of Canadian data for resources and emissions was assigned an uncertainty of 10%.
7. Uncertainty associated with EF based on previous empirical data and professional judgment was assigned an uncertainty value of 30%.



7.9 ENVIRONMENTAL BENEFITS RESULTS

This section presents the summary data from the Excel spread sheets. Excel file is embedded in this Section. Click on the pin on the right to access file.



Table 7.1 - Environmental benefits summary per functional unit

<i>Bitumen Feedstock</i>	CO ₂ e (kg/bbl Marine fuel)		SO _x (kg/bbl Marine fuel)		NO _x (kg/bbl Marine fuel)		PM (kg/bbl Marine fuel)		CO (kg/bbl Marine fuel)		VOC (kg/bbl Marine fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline	151	10%	0.13	8%	0.12	13%	0.02	10%	0.06	12%	0.03	11%
Project	138	6%	0.04	4%	0.16	6%	0.01	6%	0.07	6%	0.02	6%
Reduction from Baseline	13	139%	0.10	11%	-0.04	47%	0.01	22%	-0.01	81%	0.01	25%
<i>VR Blend Feedstock</i>	CO ₂ e (kg/bbl Marine Fuel)		SO _x (kg/bbl Marine Fuel)		NO _x (kg/bbl Marine Fuel)		PM (kg/bbl Marine Fuel)		CO (kg/bbl Marine Fuel)		VOC (kg/bbl Marine Fuel)	
	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-	Value	+/-
Baseline Scenario	69	7%	0.13	7%	0.13	9%	0.02	8%	0.06	9%	0.01	7%
Project	55	5%	0.07	8%	0.16	8%	0.01	10%	0.07	8%	0.03	9%
Reduction from Baseline	14.3	42%	0.06	18%	-0.03	56%	0.00	69%	-0.01	79%	-0.01	20%

Table 7.2 - Environmental benefits forecast for the Canadian market

Year	New installation	Additional Annual Capacity (bbl)	Cummulative Annual Capacity (bbl)	GHG Reductions in ref. year (kilotonnes/y)	SO _x Reductions in ref. year (tonnes/y)	NO _x Reductions in ref. year (tonnes/y)	PM Reductions in ref. year (tonnes/y)	CO Reductions in ref. year (tonnes/y)	VOCs Reductions in ref. year (tonnes/y)
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	1	625,000	625,000	8	59	-24	5	-7	8
2021	1	1,875,000	2,500,000	32	238	-94	18	-26	34
2022	0	0	2,500,000	32	238	-94	18	-26	34
2023	1	6,250,000	8,750,000	121	627	-298	36	-85	-49
2024	0	0	8,750,000	121	627	-298	36	-85	-49
2025	1	12,500,000	21,250,000	281	1,817	-770	126	-215	120
2026	0	0	21,250,000	281	1,817	-770	126	-215	120
2027	0	0	21,250,000	281	1,817	-770	126	-215	120
2028	0	0	21,250,000	281	1,817	-770	126	-215	120
2029	1	6,250,000	27,500,000	361	2,411	-1,006	172	-280	204



Table 7.3 - Environmental benefits forecast for the Rest of the World market

Year	New installation	Additional Annual Capacity (bbl)	Cummulative Annual Capacity (bbl)	GHG Reductions in ref. year (kilotonnes/y)	SOx Reductions in ref. year (tonnes/y)	NOx Reductions in ref. year (tonnes/y)	PM Reductions in ref. year (tonnes/y)	CO Reductions in ref. year (tonnes/y)	VOCs Reductions in ref. year (tonnes/y)
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0
2022	1	6,250,000	6,250,000	89	389	-204	17	-59	-82
2023	1	6,250,000	12,500,000	179	778	-408	35	-117	-165
2024	1	6,250,000	18,750,000	268	1,168	-612	52	-176	-247
2025	1	6,250,000	25,000,000	357	1,557	-816	69	-234	-330
2026	1	6,250,000	31,250,000	447	1,946	-1,020	87	-293	-412
2027	0	0	31,250,000	447	1,946	-1,020	87	-293	-412
2028	0	0	31,250,000	447	1,946	-1,020	87	-293	-412
2029	1	6,250,000	37,500,000	536	2,335	-1,224	104	-351	-495



8.0 SENSITIVITY ANALYSIS

Sensitivity analysis consists of examining the likely variance of input factors. Table 8.1 presents the sensitivity analysis for environmental impact quantifications for the baseline and the project.

Table 8.1 - Sensitivity analysis

Sensitivity Parameter	Variations in Parameter	Potential Variation	Justification of Selection
Bitumen extraction method and emissions	Bitumen extraction method, energy inputs and emissions	High	Best available source Project will use Bitumen directly after extraction so no dilbit required for transportation while the baseline bitumen has to be sent to refinery using dilbit Same source was used for both project and baseline
Electricity source	Only used for project based on location	Low	Best available method
Material and construction of DSU facility	Data for DSU is not available, however, there is also no activity data for the baseline (upgrader)	unknown	No activity data available considered insignificant over the lifetime of the facility
DSU onsite activity data	Based on estimates from Field Upgrading	High	Best available estimates available at this stage
Feedstock used for DSU and DMB other than bitumen	The activity data and onsite emissions were based on data from EERA	High	EERA is a specific study for MRF refinery per type of fuel When comparing total emission from feedstock and operation reported in the EERA there is a large variation from GREET 2016 emissions from bunker fuel production
DMB	The activity data and onsite emissions were based on data from EERA	High	EERA is a specific study for MRF refinery per type of fuel



9.0 REFERENCES

¹ <https://www.platts.com/IM.Platts.Content/InsightAnalysis/IndustrySolutionPapers/SR-IMO-2020-Global-sulfur-cap-102016.pdf>

² Energy and Environmental Research Associates (EERA). 2008. Total fuel cycle analysis for alternative marine fuels: Sulfur and CO₂ emissions trade-offs of California's proposed low-sulfur marine fuel rule. Final Report. California Air Resources Board.

³Energy and Environmental Research Associates (EERA). 2008. Total fuel cycle analysis for alternative marine fuels: Sulfur and CO₂ emissions trade-offs of California's proposed low-sulfur marine fuel rule. Final Report. California Air Resources Board