

Development of Optimal Energy Infrastructures for the Oil Sands Industry with Effective Steam Management

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Abstract

The Athabasca oil sand mines are a valuable natural resource and a large source of revenue. There has been a significant investment made into the recovery of oil from these oil sands reserves. One of the major concerns is the high natural water consumption in the process and methods of conservation of water and energy. Water and steam management are essential for the development of optimal energy infrastructures for the oil sands industry. This paper focuses on a case study on the effective steam management for an existing oil sands company in Canada. Based on an analysis of the material and energy balances of the existing plant, several design improvements were proposed. These design improvements focus on recovering energy lost due to steam wastage and provides effective and energy efficient methods of steam generation to meet the company's requirements. Design simulations were completed using Aspen Plus, and accordingly a techno-economic analysis evaluating the feasibility of the proposed design improvements was conducted.

Keywords

Steam management, oil sand operations, wastewater, optimization.

1.0 Introduction

The Alberta oil sands, which comprises of 174 billion barrels of oil currently, contribute towards about 60 percent of world's investable oil reserves in addition to being the world's largest capital project. However, in order to produce one million barrels of oil every day, the industry would require withdrawals from the Athabasca River that is enough to sustain a city populated with two million people annually (Davidson and Hurley 2007). An Alberta report, entitled Investing in our future, noted that "over the long term, the Athabasca River may not sufficient flows to meet the needs of all the planned mining operations and maintain adequate flows." Thus there is a concern for the amounts of water being withdrawn and the oil sands industry must look into options of conserving water.

Furthermore, the Petroleum Technology Alliance Canada has recently stated that its largest concern in the oil sands production was the amount of water being used as well as re-used because bitumen production is much more fresh water intensive than any other oil production operation. Thus, it is important to raise the awareness of the need to conserve water throughout the oil sands industry.

According to the Canadian Association of Petroleum Producers, it is predicted that by 2015 the amount of upgraded bitumen production is predicted to increase to about three million barrels per day, compared to the current amount of one million barrels every day. At that point in time, it will be already too late to address the impacts of the rapid energy development on water scarcity and to responsibly consider options to mitigate such a problem. So, it is important for oil industries to take steps in order to try and conserve water without further delay (Ordorica-Garcia 2007).

Oil and gas prices are very unpredictable and thus, controlling the cost of energy used in a process has become crucial (Russel 2007). Rising energy prices can result in the exhaustion of the base cost of the process, unprofitability and competitiveness. Steam has also been a primary utility for several processes and many companies have now invested in trying to improve and manage their steam systems more efficiently (Risko 2008). Thus, the awareness for steam management is evident in the industry worldwide, and this paper will be providing an option to effectively manage as well as conserve the amount of steam being used within a particular process. Worrel et al. (2001), Yukako (2001), Therkselen and McKance (2013), and several authors of studies in the literature have focused on proposing techniques to effectively manage steam in the industry to entail significant energy savings.

This paper focuses on effective steam management for a crude oil processing plant. Based on an analysis of the mass and energy balances of the plant, the units that provide high potential of energy savings (i.e. steam waste reduction) will be identified. Accordingly, a technique to effectively manage steam being used in the upgrading process of the plant will be proposed. A techno-economic feasibility analysis of the proposed design is presented in this paper. The feasibility study will be assessing the energy efficiency, total cost, payback period as well as the ability of the options to compile with the country's government regulations.

2.0 Waste steam recovery

The production of one barrel of synthetic crude oil relies on energy supplied by the on-site utilities plant. The utilities operation supplies steam, water, air, nitrogen and electricity. Fuel for utility steam and power production is primarily from Coker burner overhead gas and plant fuel gas. The steam is supplied by three boilers rated at 800 klb/hr at maximum continuous rating each, two carbon monoxide (CO) boilers rated at 750 klb/hr MCR each and two once through steam generators (OTSGs) rated at 224 klb/hr each.

Steam is produced at three different pressure levels that are used in several process units. 600 psig steam is used in large and medium sized turbines such as cooling water circulation pump drivers and process steam heating. The 600 psig steam is directed to the 600 psig/ 150 psig and 600 psig/ 50 psig letdown stations for header pressure control as required. 150 psig steam is mostly used in the steam tracing system, and also in upgrading units where it is used as stripping steam, fluidization steam and for process heating. Any excess 150 psig steam is letdown through pressure control to the 50 psig header, which is mostly used for recycle water trim heaters, diluents recovery unit and the amine unit reboilers.

Water used for steam production is taken from the Athabasca River. The water imported is first sent to the gravity clarifier that induces the first separation step. The impurities present in the raw water are separated from it as they settle down as sludge. This water is then sent for further separation to the Water Treatment Plant (WTP). The water that comes out of the WTP, demineralized water, is sent to the deaerators (D201, D224 and D202). The water from the deaerators is sent to seven boilers (CO1 boiler, CO2 boiler, CO3 boiler, CO4 boiler, 201 boiler, 202 boiler and 203 boiler) that produce steam in the form of 50 psig steam, 150 psig steam, 600 psig steam, potentially dirty condensate, stripped sour water, cold condensate and plant 9 condensate. The flow rate of demineralization water entering the system is 8657.9 USgal/min. The steam used is eventually vented to the atmosphere and only 6.2% of it is recovered. The distribution of steam in its various forms is illustrated in Figure 1. High potential in energy savings can be produced by reducing 600 psig steam waste ("Steam Distribution System" 2006).

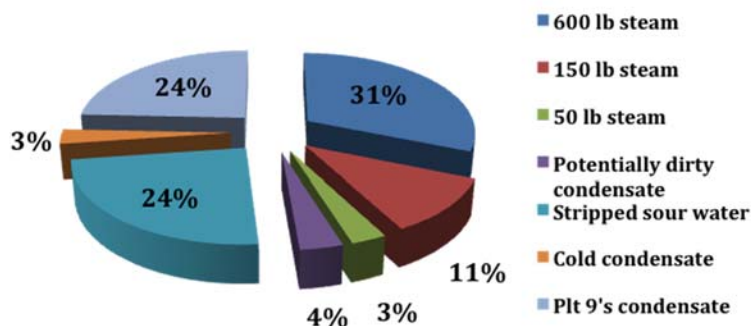


Figure 1: Amount of steam wasted in the form of different commodities

2.1 Heat recovery design

With today's high fuel cost, companies cannot afford to release steam into the atmosphere. Typical chemical process plants should be able to recover 60% of the condensate from steam vented to the atmosphere (Gibson 2010). When steam is vented to the atmosphere, a specific amount of heat energy will be released for each low-pressure condition (Swagelok 2010). This heat energy causes an effect called flash steam, which is a percentage of condensate being re-evaporated at low pressure. In any steam distribution system in a process plant, there should be some means of returning back the energy from vented steam to other sections of the plant. An analysis was conducted on the 600 psig steam distribution system existing in the plant to determine sources of steam wastage and finding effective means of managing it. As mentioned before, the 600 psig steam system resulted in the highest amount of steam wastage when compared to other steam commodities. Figure 4 shows the 600 psig steam distribution system in the utilities section of the plant. Water from the Water Treatment Plant (WTP) is used as the main source for generating steam and enters into the boiler at about 2188 Kilo pound per hour (KPPH). The inflow and outflow material balance numbers are represented in units of KPPH.

Roughly 1 tonne/hr of steam is being vented to the atmosphere in the current setup from plants 8-1 and 12-1. With today's energy pricing and the need to reduce emissions, a plant's steam/condensate systems cannot afford to vent flash steam to the atmosphere. The cost of venting approximately 1000 lbs of 600 psig steam commodity in the plant is \$12.60. This yields a cost of approximately \$221,000/yr for the plant by not effectively managing the venting steam to the atmosphere. As part of our design analysis, to prevent the flash steam loss to the atmosphere in the form of 1 tonne/hr, installing a flash steam vent condenser will prove useful. By doing so, the energy from the exhaust steam can be re-circulated to provide heat to other processes in the plant. Based on the pressures involved in the process, 10%-40% of the energy content of the condensate is contained in the flash steam. By using a heat exchanger, the energy from the vented steam can be recovered and used as a source of heat for another fluid in a separate process. By recovering the flash steam energy, the boilers will have to produce less steam, thereby reducing emissions from the boiler operation. In the case of our design, the energy lost to the atmosphere (in the form of steam) is recovered using a vent condenser to heat a mixture of benzene, toluene and octane. A standard shell and tube heat exchanger with a U-tube and counter flow configurations is designed to serve the purpose for this application (Figure 2). The process fluid consumes the flash steam and allows the condensate to drain back into the condensate tank.

The vent condenser design and operation has been simulated using Aspen Plus software. Numerous iterations of the simulation were performed with different configurations, but the shell and tube exchanger configuration resulted in the lowest area required and hence the least amount of cost. In the design steam is introduced in the shell side and the process fluid in the tube side. The process fluid is a hydrocarbon mixture of benzene, toluene and octane, which needs to be maintained at 165 °F. The design modification proposed is to heat the fluid with the 1 tonne/hr of steam vented to the atmosphere from the 600 psig steam system.

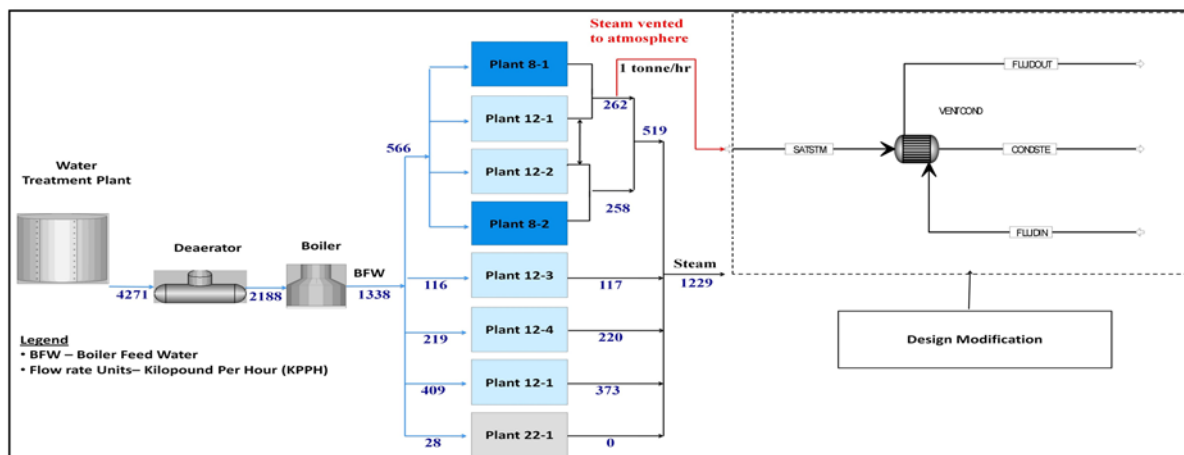


Figure 2: 600 psig steam distribution system with recommended design modification

2.2 Heat recovery simulation results

The design of a heat exchanger involves a two-pass shell with eight tube passes. Increasing the number of tubes and passes increases the heat duty of the exchanger. This results in significant energy consumption for the exchanger. The desired temperature gradient for the process fluid was achieved with the two-pass shell with eight-tube pass configuration. The pressure drop across the exchanger was within acceptable limits, and would have been significantly influenced by increasing the number of shell and tube passes. The detailed specifications of the exchanger are summarized in Table 1.

Table 1: Shell and tube heat exchanger specifications

Heat exchanger specifications			
TEMA Shell type	Two Pass Shell	Tube type	BARE
No of Tube Passes	8	Total number of tubes	80
Exchanger orientation	Horizontal	Tube length	16 ft
Inside Shell Diameter	3.33 ft	Nominal Diameter	0.75 in
Shell to Bundle clearance	1.83 ft	Inside Diameter	0.0486 ft
Tubes in Baffle Window	YES	Outside Diameter	0.0625 ft
No of segmental Baffles	40	Tube Thickness	0.0069 ft
Tube sheet to 1st baffle distance	0.762 ft	BWG	14
Shell-baffle clearance	0.021 ft	Pattern	Triangle
Tube-Baffle clearance	0.0013 ft	Pitch	0.083 ft
Nozzle Inlet Diameter	1 ft	Material	Carbon Steel
Nozzle Outlet Diameter	1ft	Thermal Conductivity	29.68 Btu-ft/hr F

From the stream results (Table 2), it is evident that the process fluid temperature increased by 43 °F with only 1 tonne/hour of steam flow rate. The heat duty and exchanger area are used to calculate the cost of the exchanger. The overall objective of raising the temperature of the process fluid to 165 °F has been met. This simulation indicates that steam can be successfully captured and the heat generated can be effectively used in the process.

Table 2: Stream results for the two-stage compressor

	Inlet	Outlet
Hot side	Saturated Steam	Condensate
Temperature (°F)	383	379.5
Pressure (psia)	195	195
Vapor Fraction	1	0
Cold side	Process In	Process Out
Temperature (°F)	122	165
Pressure (psia)	29.4	29.4
Vapor Fraction	0	0
Heat Duty (kW)	567.9	
Exchanger Area (ft²)	252	

3.0 Steam generation

There is an existing steam deficit in the bitumen upgrading processes of the plant. The gross steam required by the upgrading process is 873.28 tonnes steam/hr and the amount produced internally is 517.25 tonnes steam/hr. Therefore, the deficit amount of steam (356.03 tonnes steam/hr) has to be recovered in the form of superheated steam at 915 psi. This imposes a requirement for an alternate form of steam generation in the bitumen upgrading Process.

The plant has four cooling towers. Each of them has water being wasted as blow down water. The cooling tower that can be efficiently used to meet the deficit is the UE-1 cooling tower. The UE-1 forced draft and cross flow process-cooling tower is 150,000 USgal/min in capacity. It consists of 18 identical cells arranged side by side. Figure 3 below shows the schematic of the UE-1 cooling tower.

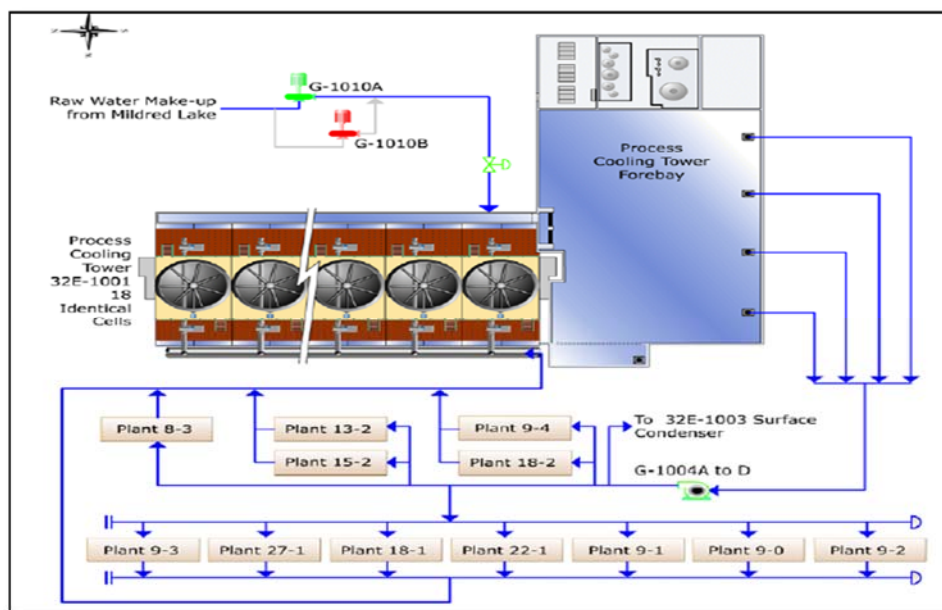


Figure 3: Schematic of UE-1 process cooling tower

The process cooling water tower is an open cooling system and losses of cooling water occur through drift, evaporation, blowdown and leaks. Blow down is the controlled discharge of water from the system to reduce total dissolved solids (TDS) and turbidity, and to control cycles. Loss of water through blow down can be a controlled event, by manipulating a control valve ("UE-1 Cooling Tower" 2008). The water wasted as blow down water is clean treated water and hence it can be used to meet the steam deficit in the upgrading process. The total blow down losses was calculated to be 1,470 m³/hr of water. Twenty five percent of the intentional blowdown losses (356 tonnes/hr) can be converted to superheated steam at 915 psig and 500°C.

3.1 Steam generator design

To achieve the required design specifications, the use of a centrifugal compressor was considered. Due to the high temperature and pressure of the steam, which cannot be handled by a single-stage compressor, a two-stage centrifugal compressor was chosen to meet this requirement. Multi-stage centrifugal compressors are suitable when working with large volumes and high superheated steam (Ling 2011). When a compressor has more than one stage, an intercooler is installed between each two stages. The main functions of the intercooler are protection and efficiency of the compressor. The intercooler cools down the compressed medium from the discharge of the first stage prior to the steam entering the next stage. This decrease in temperature reduces the likelihood of the damage of components of the compressor. Large industrial size compressors typically have a water-cooled intercooler in between the stages of compression. Figure 4 shows a diagram of the intercooler in between stages in a two-stage centrifugal compressor.

The material to be used for the compressor is a 410 stainless steel impeller and a nickel-plated casing. The 410 stainless steel has 11.5% chromium content and it has the ability of resisting dry atmospheric conditions, can retain itself in fresh water, is corrosion resistant and can withstand steam and hot gases. A nickel-plated casing was chosen, as nickel is usually the choice of material for steam applications due to its capability of withstanding high pressures. (Rennie 2006).

3.2 Steam generation simulation results

The simulations performed as a result keep the specific outputs in perspective. There is minimal scope available for optimization due to the fixed parameters. However, justifications with regard to process operation and cost have been provided for the recommended design. The multi stage compressor has been modeled in Aspen Plus. The design scheme involves utilizing a boiler to arrive at saturated steam from the water feed. The steam is then sent to the multistage compressor for the required pressure and temperature increase to 915 psig and 500°C. The deficit steam amount is 356 tonnes/hr, which is high, and hence the flow is split up into three streams with each multi stage compressor responsible for 120 tonnes/hr. The overall volume is realistically too high for only one piece of equipment and as a safety feature, it is generally recommended to have more than one piece of equipment, in case of a potential failure. The simulation layout is shown in Figure 5.

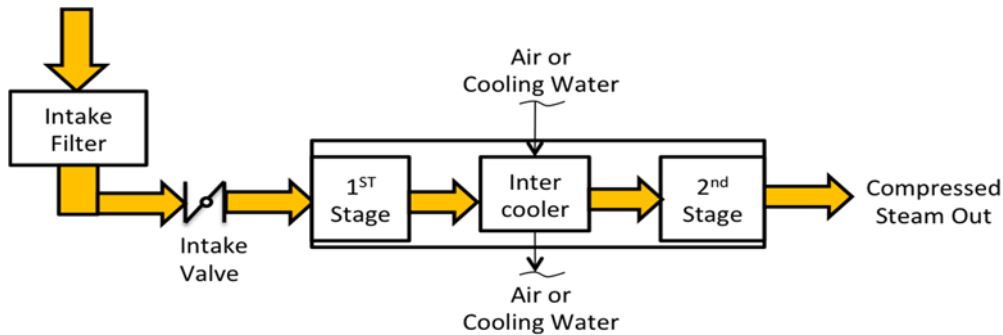


Figure 4: Intercooler for a two-stage centrifugal compressor

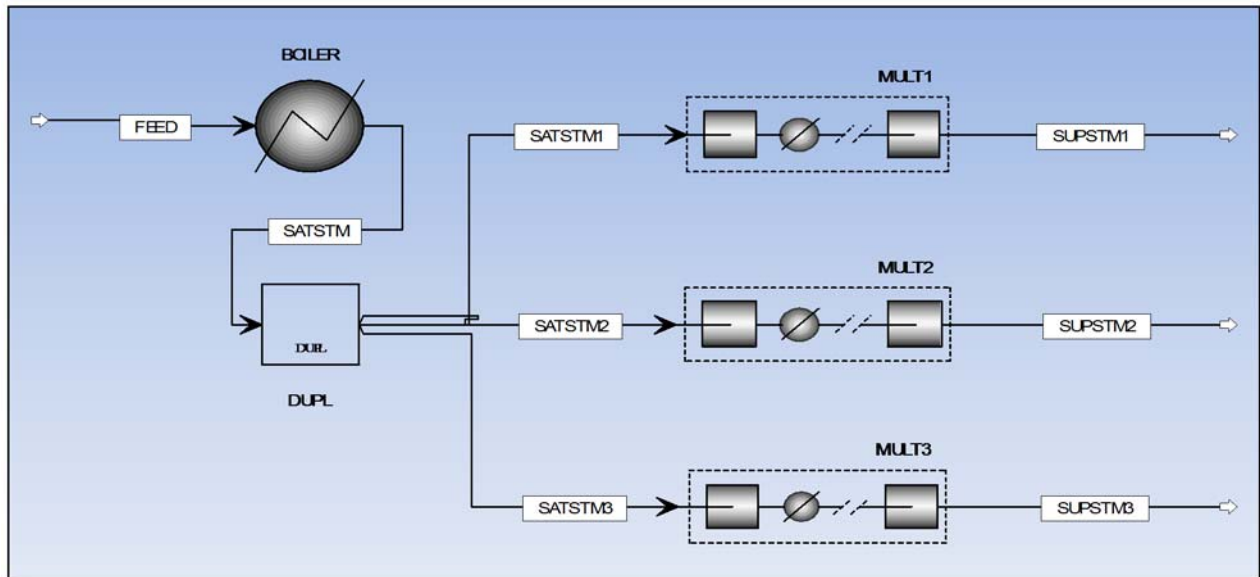


Figure 5: Simulation layout for the two-stage multi compressor

The incoming feed water is at 25 C and 14.7 psig. This is typically the temperature and pressure of the blow down water as was specified in the company's data. The boiler is designed to alter the vapor fraction of the incoming steam and raise the pressure of the saturated steam to 600 psig. The saturated steam is then passed on three identical multi stage compressors, and superheated steam is generated as a result. The multi stage compressors have been specified to have the outlet conditions of 915 psig and 500°C. An isentropic process model was selected, as this is the typical industrial configuration for the nature of operation. The results of the simulation can be summarized in Table 3. The total heat duty required was calculated as 18,246 kW. The payback period for a multi stage compressor of this size is typically 3-5 years (Bilge and Temir 2004).

Table 3: Multi-stage compressor simulation results

Compressors	Heat Duty (kW)	Pressure (psi)	Temp (°F)
Stage 1	2012	741	553
Stage 2	3327	915	1020
Intercooler	Heat Duty (kW)	Pressure (psi)	Temp (°F)
Stage 1	12,907	741	932
Total	18,246		
Stream Results	Feed	Saturated	Superheated
Temperature (°F)	77	488	932
Pressure (psi)	15	600	915
Enthalpy (MMBtu/hr)	1816	1489	1437

3.3 Sensitivity analysis

The combination of boiler and multi-stage compressor is the selected method of steam generation. Varying certain parameters in the boiler greatly affects the results in the multi-stage compressor. Varying the pressure in the boiler has a significant impact on the heat duty of the multi-stage compressor. The effect of varying the pressure of the boiler on the required heat duty of the compressor is presented in Figure 6 (a).

By increasing the boiler pressure a steep decline in compressor heat duty can be observed. The purpose for this examination is to optimize the costing for the system. The costing for a multi stage compressor is highly dependent on the heat duty value of the centrifugal compressors and the intercooler. The intercooler heat duty remained fairly stable with a change in the boiler pressure and its impact on costing is minimal. Hence, it can be ignored for the next component of the sensitivity analysis. The primary variable influencing cost is the centrifugal compressor heat duty as is observed in Figure 6 (b). By increasing the boiler pressure from 250 psig to 600 psig, the cost for the centrifugal compressors drops from 24 million to 3.2 million. This is a significant decrease in the overall cost of the configuration. However, increasing the boiler pressure does increase the boiler cost. The rate of increase is not significant and the cost only varies from \$3 million to \$3.8 million. The increase in boiler cost is significantly offset by the decrease in the compressor cost. Hence, the optimal point of operation is at a boiler pressure of 600 psig. This position yields the lowest heat duty for the centrifugal compressor and hence the lowest cost of the system. It is recommended to run the system at these conditions. This is a critical consideration when designing systems of this magnitude.

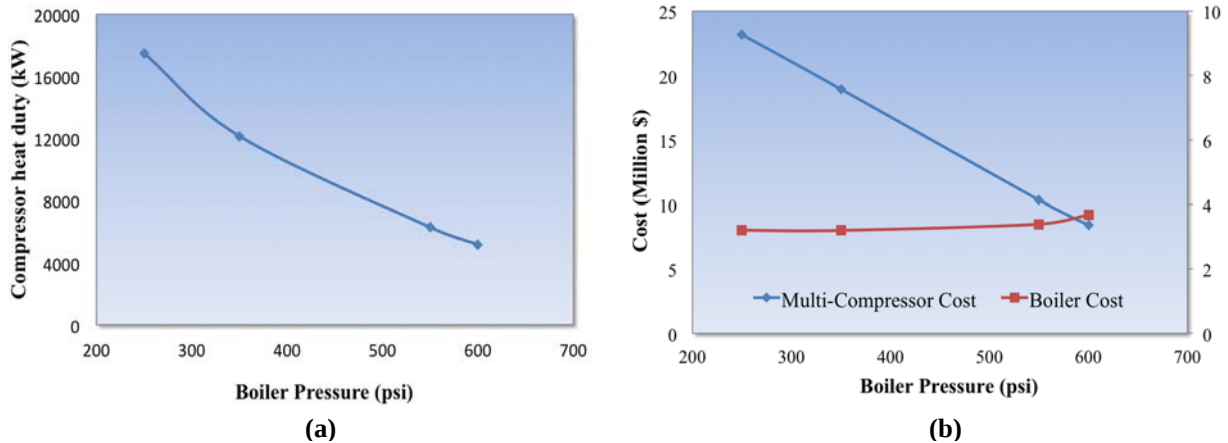


Figure 6: Effect of boiler pressure on compressor heat duty (a) and equipment cost (b)

4.0 Feasibility analysis

A feasibility study was conducted to assess the viability of the proposed designs. The outcome of the feasibility study indicates whether it is justifiable to proceed with the proposed design. A cost/ benefit analysis was conducted to determine the benefits and savings of the proposed design systems. Before taking any future actions it is important to accurately weigh the cost vs. benefits of each option. A comparison between the existing system and the proposed new design system for effective steam management was conducted by assessing the overall heat duty, source of water, payback period, and capital and installation costs.

The process units involved in the capital cost estimation are the heat exchangers and compressor. To estimate their capital cost it is necessary to obtain an estimation of their sizing. This was based on information about the flowrate, temperature, pressure, and heat duty from the material and energy balance, which were obtained from the simulation. This sizing data can be used along with cost correlations available in the literature (Turton et al. 2003). The heat exchanger cost depends on the total heat transfer area. The overall heat transfer coefficient is typically $362.5 \text{ W/m}^2 \text{ }^\circ\text{C}$ (Perry and Green 2007), and the calculated heat exchanger surface area is then used for cost estimation. Sizing of the pumps rely on power consumption. The pumps are sized based on centrifugal types by considering material and pressure factors.

Steam lost to the atmosphere in the form of 600 psig saturated steam is nothing but heat and energy lost from the system to the atmosphere. Steam vented to the atmosphere is very expensive. The amount of steam lost as 600 psig steam is one pound per hour. Each pound of steam lost results in a pound of fresh water make up which needs to be heated. The annual cost for venting 1 lb/hr of steam to the atmosphere is \$221,000. In this paper a shell and tube heat exchanger is used to recover the heat lost by the steam vented to the atmosphere. The heat exchanger has an area of 252 ft² and it costs \$17,700/year. Compared to annual cost of venting, installing a shell and tube heat exchanger to capture the heat of the steam being lost represents high potential for cost savings.

The existing upgrading process requires a heat duty of 30,458 kW to generate superheated steam at 915 psig and 500°C. The heat duty required by the multi-stage compressor is 19,610 kW, which is considerably lower. The current source used for producing the superheated steam used by the existing upgrading process is natural water from the Athabasca River. Alberta had now set strict limits on how much water oil sands companies can withdraw from the Athabasca River. This sets a high level of protection that is balanced with the needs of the community and industry. The goal is to ensure low impact to the river ecosystem, coupled with water conservation and innovation by water users. The proposed design system uses the blow down water from the UE-1 cooling tower. Currently, twenty five percent of the treated blow down water from the cooling tower is wasted. This source of water is used by the proposed design technology to produce superheated steam since it does not require additional treatment. By using an already existing source of water within the company premises, it reduces the amount of fresh water that needs to be withdrawn from the Athabasca River thereby resulting in reduction of fresh water consumption, which is the primary goal of this study.

The configuration of three multi-stage compressors was used for achieving the desired results. The capital and installation costs for one unit configuration of the two-stage compressor were calculated as \$8,000,000/yr over a payback period, which was roughly estimated as 3-5 years. The costs related to this study are relatively high, but the design option successfully meets the steam deficit of the upgrading process and results in water conservation.

5.0 Conclusions

Steam is a major utility and its proper management could entail substantial savings. With oil and gas prices remaining unpredictable, controlling the cost of the energy used during processing is especially challenging. As a major utility supplying many process applications, steam is a highly effective heating medium and hence steam management is an extremely important consideration.

Venting steam at a pressure level of 600 psig is very expensive. The cost associated with installing a shell and tube heat exchanger to capture the wasted steam is considerably lower than venting it to the atmosphere. These annual costs are \$17,700 and \$221,000, respectively. A complete design of the heat exchanger was carried out, and the total surface area of the heat exchanger is 252 ft². Compared to annual cost of venting, installing a shell and tube heat exchanger to capture the heat of the steam being lost represents high potential for cost savings.

A multi-stage compressor was implemented to overcome the steam deficit (356 tonnes steam/ hr) in the bitumen upgrading process. The overall heat duty required by the two-stage compressor was 18,246 kW, with an associated annual cost of \$8 million and the pay back period is approximately 3-5 years. A trade off should be made between the cost and the energy. In the future a multi-stage compressor is the more feasible option since it requires lesser energy. When other costs will be implemented in the future by the government, since the energy requirement for the multi-stage compressor is lower than that of the existing design.

In future research it would be interesting to investigate the effect of combining excess heat generated from refineries or other industries with heat demanding nearby industries on reducing total green house gas emissions. It is also worth investigating comparing different feasible technologies and alternatives for excess heat utilization on the basis of increasing global environmental sustainability.

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Biography

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