UNIVERSITY OF CALGARY

ENCH 423 / ENPE 423 / ENER 400 Term Project

CO_2 Recovery from Flue Gas Through Amine Scrubbing

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Date of Submission: April 5, 2019

Letter of Transmittal

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Re: ENER 400/ ENPE 423 Term Project Winter of 2019

Date: April 5, 2019

This design project report is to be presented to Dr. Qingye Lu, Professor of ENER 400/ ENPE 423/ ENCH 423 – Engineering Design and Economics. This design project report was performed by Group 34. All data found, researched and calculated are referenced.

We researched and analyzed the process of Amine Scrubbing, Amine Scrubbing examines the absorption of CO_2 from the atmosphere. We researched the economic and the technical sides related to our study to determine if the project is feasible.

We chose our plant location to be by the Athabasca Oil Sands at Fort McKay, near Fort McMurray. The reason why we chose this location is because of two factors: the high flow rates of CO_2 coming out of refineries, meaning much more concentration of CO_2 in the atmosphere; and because of the lack of competitors present at this location. Because we are reducing the emission of greenhouse gases emitted by these refineries, we will also be contributing to solving problems occurring in our world today such as global warming and climate change.

Please refer to the Design Project report for more detailed information regarding Amine Scrubbing

Best regards,

Group 34

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Table of Contents

Nomenclature 5
Executive Summary 6
Background Information 1
Market Evaluation 1
Case Study 3
Process Design and Description 3
  Heat Integration 5
Plant Location 6
Economic Analysis 7
  Capital Cost Estimation 8
  Operating Costs 9
  Economic Potential: 9
Sensitivity Analysis 10
Risk Assessment 11
  Process Hazard Analysis 11
  Environmental Impact 11
  Commercial Risk 12
Conclusions and Recommendations 12
References 13
Appendices 15
  Appendix A - Background Information 15
  Appendix B – Case Study 16
  Appendix C – Process Design Tables and Figures 17
  Appendix D - Equipment Specifications 22
  Appendix E – Plant Location Figures 27
  Appendix F – Cost Analysis 29
  Appendix G – Risk Analysis 31
  Appendix H – Economical Analysis Calculations 33
  Appendix I – Condensed Full Report 35
  Appendix I – Full Material and Energy Report 37

Table of Figures

Figure 1: Total Carbon Dioxide Emissions from Fossil Fuels in 2010 15
Figure 2: Process Chemistry Loop for Carbon Engineering DAC Pilot Plant 16
Figure 3: General Process Flow Diagram as Described by the GPSA 17
Figure 4: PFD of Amine Scrubbing Process 19
Figure 5: HYSYS Simulation Run and Stream Data for Flue Gas 19
Figure 6: HYSYS Simulation Run and Stream Data for Flue Gas 20
Figure 7: Variation of Pressure and Temperature with Tray Position for Desorber Column 20
Figure 8: Un-optimised E-100 Heat Exchanger 21
Figure 9: Optimised E-100 Heat Exchanger 21
Figure 10: Plant Location Near Fort Mackay 27
Figure 11: Geological Formations of the Athabasca Oil Sands Region 28

Table 1: Project Operating Costs of the Quest CCS Facility 16
Table 2: Inlet and Outlet Mass Flowrates 17
Table 3: Inlet and Outlets Energy Flow rates 17
Table 4: Data Regarding the Flue and Atmospheric Models 18
Table 5: Comparison Between Atmospheric and Flue Gas Model 18
Table 6: Information about Items, Rates, Operating Pressure and Temperature 22
Table 7: Absorber and Desorber Conditions and Sizing Specifications 22
Table 8: Desorber Reflux Condenser Sizing Specifications 23
Table 9: Desorber Reboiler Conditions and Sizing Specifications 23
Table 10: Desorber Reflux Pump Efficiency and Specifications 24
Table 11: Desorber Heat Exchanger Specifications and Design Conditions 25
Table 12: Process Heater/Cooler Specifications and Design Conditions 26
Table 13: CO2 Final Separator Design Specifications and Operating Conditions 27
Table 14: Summary of Project Capital Cost 29
Table 15: Summary of Operating Costs 29
Table 16: Net Cash flow Analysis for The First Five Years 30
Table 17: Profitability Indicators for the First Five Years 30
Table 18: Capital Cost Estimation 30
Table 19: Process Hazards 31
Table 20: Environmental Hazards 31
Table 21: Commercial Risks 32
Table 22: Qualitative Risk Matrix 32

Equation 1: Sample Calculations Regarding Process Design 18
Equation 2: Annual Deprecation Cost 33
Equation 3: Unit Depreciation 33
Equation 4: Total Revenue 33
Equation 5: Annual Income Before Tax 33
Equation 6: Product Cost 33
Equation 7: Economic Potential 34

Nomenclature

AER: Alberta Energy Regulator

AEP: Alberta Environment and Parks

BFD: Block Flow Diagram

CAPP: Canadian Association of Petroleum Producers

CCS: Carbon Capture and Storage

CO_2: Carbon Dioxide

DAC: Direct Air Capture

EOR: Enhanced Oil Recovery

FIC: Fixed Capital Investment

GHG: Greenhouse Gas

GPSA – Gas Processors Suppliers Association

IRR: Internal Rate of Return

ISBL: Inside Battery Limits Investment

LSD: Legal Subdivision

Mbarrels: 1000 barrels

MEA: Monoethanolamine

MM: Million

NPV: Net Present Value

NRR: Net Return Rate

OSBL: Outside Battery Limits Investment

PFD: Process Flow Diagram

WC: Working Capital

Executive Summary

The team decided to establish our plant near Fort McKay. The purpose of our plant is to recover carbon dioxide, a greenhouse gas, that is being polluted into our atmosphere by employing a process referred as Amine Scrubbing. This process uses an amine solvent to absorb the CO_2 from flue gas. Because Alberta has a high demand for natural gas, there are a lot of CO_2 emissions in the atmosphere, thus we can expect that there is a higher concentration of CO_2. It is estimated that there are 135,100 tonnes of CO_2 being released as flue gas per day.

As estimated though ASPEN, our capital cost for this project was $19MM USD, our contingency factor was 10%. This was to prepare for unexpected expenses that might arise, thus our total FCI was said to be $21 MM USD. With the location factor and the working capital, the final FCI calculated was around $38 MM USD. The utilities cost estimated by ASPEN was estimated to be at about $51 MM USD, and the book value of the equipment was $17 MM USD. Using the straight-line depreciation method, the salvage values for these utilities after 10 years are 3.6 MM USD.

The project is technically feasible and simulated on ASPENHysys but has proven to be not economically feasible. The cost analysis demonstrated that the capital cost and operating cost way too high for the relatively little sales - due to the low value for CO_2. The cost analysis was performed with a sales price of $50 per metric ton of CO_2. The CO_2 is sold for enhanced oil recovery operations, which utilizes CO_2, to the oil production companies nearby. **Overall there is no profit being produced thus making the project economically non-feasible, unless receiving a government grant.** Regardless, selling the CO_2 allows us to offset the recovery costs.

In our risk analysis there were three types of risks/hazards: process hazards, environmental hazards, and commercial risks, each having their own probable risks. In process hazards, the two most probable risks were amine degradation and the change in flue gas composition due to corroded pipes. For environmental hazards, the most probable was waste water getting released into the atmosphere. For the commercial risk the most probable issue was that the project is not running according to schedule. However, this only has a moderate impact on the project and doesn’t harm any of the workers or the environment.

Background Information

Amine scrubbing has been used since the 1930s to separate carbon dioxide from natural gas and hydrogen. The absorption of CO_2 into aqueous amine solution is regarded to be one of the most promising technologies for post combustion CO_2 capture due to its maturity, cost effectiveness, and capacity to handle large amounts of exhaust streams. [1]

It has been noted that CO_2 concentrations have been rising since the industrial revolution. This is primarily due to anthropogenic CO_2 emissions, commonly from combustion of fossil fuels for energy, the of increase has grown throughout the years as we begin to depend more and more on the burning of fossil fuels for energy – this can be seen from Figure (1) of Appendix (A), where more populated areas of the world demand more energy and therefore use more fossil fuels. [2] This will result in an increase in global temperatures which is commonly referred to as global warming. This in turn leads to issues such as melting of snow in the ice caps, rising sea levels, and more severe weather patterns. With that said, reducing the increase of CO_2 concentrations is essential to reducing the risks of global warming. [3]

There are a few different types of technology options for CO_2 removal, such as absorption of CO_2 using chemical solvents, Adsorbed beds, Membrane filters. Even though these methods are effective, they also have certain drawbacks to them. For example, Absorption uses chemical solvents that are commercially available, and the operations would be done at an ordinary temperature and pressure. Certain drawbacks or problems to this method would include the heat of solvent due to regeneration being too high. Another example would be Adsorption. This method is very effective and efficient in recapturing CO_2; however, it needs to be run at very high pressure thus making it costly.[4]

Market Evaluation

One of the main reasons for considering CO_2 removal is the costs related to Carbon tax. Alberta currently has a Carbon tax program in place where $30 per tonne of carbon emissions is charged, with future increases coming in the following years. If considering the oil sands emissions limit of 100 mega tonnes that Alberta has in place as part of its Climate Leadership Plan [5], the total carbon tax currently amounts to approximately $3 billion. By capturing and redirecting these carbon emissions to other uses, such as Carbon Capture and Storage (CCS) for Enhanced Oil Recovery (EOR) and/or selling for use in other processes or products such as food grade CO_2carbon costs can be minimized and can even create profit.

This report is considering Fort McMurray as its location. As a major location for oil sands production, there is an abundance of carbon emissions present that can be captured, either by a separate capture facility or through retrofitting of existing production plants to capture emissions. Captured emissions can then be repurposed for CCS processes, and as the CO_2 is obtained “locally”, transportation costs are further reduced.

Aside from CCS, CO_2 can be sold for commercial purposes; Praxair and Air Liquide are examples of industrial gas companies that market compressed CO_2 as one of its products. As they have penetration into a wide variety of markets such as food processing and welding [6], some demand at the very minimum can be expected and therefore, a potential source of profit. A 2016 report by Synapse Energy Economics projected that in the US at 2022, the general price for CO_2 would be in the range of 15 USD to 25 USD per ton, which will increase over time. [7] However, another study conducted by Advanced Resources International Inc. in 2011 assumes a cost of $45 per ton CO_2 for use in Enhanced Oil Recovery processes [8], which suggests that more profits can be made than the projected price mentioned earlier. This, in conjunction with the carbon tax savings of $30 per ton from not releasing CO_2 into the atmosphere, provides an avenue for making profit while reducing operating costs.

Case Study

A report by the American Physical Society (APS) from 2011 states that, with current technologies, a typical direct air capture (DAC) system that uses chemicals will cost approximately $600 or more per metric ton of CO_2 removed [9]. The technical challenges of this system are further proven by the theoretical system that the APS designed; using the guideline of 20 tons of CO_2 per year per square meter of area for air flow, for a 1000 megawatt coal power plant, "a DAC system consisting of structures 10 meters high that removes CO_2 from the atmosphere as fast as this coal plant emits CO_2 would require structures whose total length would be about 30 kilometers." [9] The sheer scope of this system would have extremely high capital costs as well as regular recurring costs such as the cost for chemicals, maintenance and personnel, not to mention the amount of power required to operate this facility. A conundrum of this is that the power used by such a system will most likely be mostly sourced from fossil fuel generators which will nullify a major portion of the amount of CO_2 captured.

A study published in 2018 by a Canadian company called Carbon Engineering showed that they were able to develop a system that, through testing with a pilot plant, reduced the DAC levelized cost to a range of 94 to 232 USD per ton of CO_2 [10]. This was achieved by developing a loop process that uses the chemicals KOH and CaOH in an air-liquid contactor, as shown in Figure (2) of Appendix (B).

While this pilot system shows a significant decrease in costs compared to a typical DAC system, a carbon capture and storage (CCS) system is still much economical as proven by a currently operating facility; the 2017 annual report for the Quest CCS facility near Edmonton, Canada, states that it captures approximately 1.2 million tons of CO_2 per year for an operating cost of approximately $32 million in 2017, as shown in Table (2) of Appendix (B). [11] This results in an approximate cost of only $26.67 per ton of CO_2, which, combined with the Carbon tax savings and the government funding received, results in significant savings compared to no CO_2 capture.

Process Design and Description

The objective of the process is to remove carbon dioxide gas from atmosphere. This is performed using a liquid amine solvent that has an affinity to carbon dioxide vs other gasses. When the air and amine solvent are mixed, the amine attaches to it the carbon dioxide molecules effectively removing it from the air. This happens at the "absorbing column" is designed to allow for maximum contact between the phases. The fluids are then separated; the air is now free of carbon dioxide and is free to exhaust into the atmosphere, the liquid amine (which now contains carbon dioxide) is then taken for further processing to allow the removal of carbon dioxide so the solvent can be reused, and the carbon dioxide sold. This removal of carbon dioxide happens at the "desorption column" which essentially heats up the solvent in low pressure until carbon dioxide can escape. The lean amine (which now only carries residual loading of CO_2) is recycled back to the "absorbing column." This recycling of solvent, absorption and desorption is an effective way to remove CO_2 gas from air. A general process flow diagram described by the GPSA [12] is as illustrated in Figure (3) of Appendix (C).

This process of amine scrubbing is utilized as an effluent management system. The feed stream is carbon dioxide flue gas from a nearby facility. The process designed to release clean (carbon dioxide reduced air) air into the atmosphere and sell the sequestered carbon dioxide gas to a drilling company utilizing this gas for enhanced oil recovery. The carbon dioxide gas can also be sold for dry ice products as well soda companies. An estimated value of $50 USD per ton is placed allowing us to offset the operating cost of the waste treatment plant with some revenue.

Current CO_2 concentration in our atmosphere is 406.58 ppm and is accelerating at the rate of 0.7ppm per year. Pre industrial revolution concentration was 280ppm and is expected to cross the 500ppm mark around 2050. [13] This rapid increase in CO_2 would create a global temperature rise of 3C and would cause irreparable environmental impacts. [14] This makes $_{\text{CO2 capture}}$ and recovery necessary for the survival of the human species. Alberta has $1.24 billion to two carbon capture and storage projects which reduce carbon emission by 2.76 million tonnes per year. It is evident that the demand as well as the funding for this carbon capture process exists.

Aspen HYSYS was used to simulate the amine scrubbing process as shown in Appendix (C) as Figure (6). Amine Package was utilized with the thermodynamic model Kent-Eisenberg. 30,000 moles of inlet flue gas were assumed with a CO_2 concentration of 0.0385 mole fraction. MEA (Monoethanolamine) was used as the amine solvent. Properties of this amine solution were extracted from GPSA Data Book, 14^{th} edition (chapter 21: hydrocarbon treating) [12]. The amine circulation calculations yield a required rate of 38,812 kmol of 28% by weight MEA solution. Relevant calculations are attached in Appendix (C) as Equation (1).

A 96.3% efficient $_{\text{CO2}}$ recovery is achieved where 48.9 tonnes of CO_2 is removed from the atmosphere every hour – that is 8 and a half Olympic sized swimming pools every hour. Material Balance is as attached in Appendix (C) as Table (2).

Note that 1.63 % exists due to the recycle function employed in the simulation. To assist with the convergence of the recycle flow, an allowing sensitivity was inputted. Total consumed energy per hour is $1.23x10^9$ kJ; that is 8.8 MJ per kilogram CO_2. This is a severely high energy consumption when compared to optimized literature values of around 4MJ per kilogram of CO_2. [15] The energy balance is attached in Appendix (C) as Table (3). Note than an error of 2.65% exists due to the sensitivity of the recycle function.

Equipment were sized using Aspen HYSYS and are attached in Appendix (D) as multiple tables; Table (5) shows the sizing for key unit operations - the absorber, Desorber and an economizer (heat exchanger). The absorber (T-100) is sized for 25 trays, a vessel diameter of 10 m and a height of 12.3 m; the Desorber (T-101) is also sized for 25 trays, a vessel diameter 5.18m and a height of 20.3m; and the heat exchanger (E-100) sizing resulted in a heat transfer area of 150.8m, tube OD of 25.4mm and length of 6m, the number of shell and tube passes are 1. Temperature, pressure and vapor flow profiles for the desorber (T-101) can be found in Appendix (D), Table (8). This heat exchanger is utilized for the thermal exchange between the hot lean amine exiting the absorber and the cold rich amine exiting the desorber. This heat exchange between the two process streams allows for a reduction for hot and cold utilities.

Summary of the Utility data, with rate, cost per hour and operating temperatures and pressures can be found in Appendix (C), Table (6). Primary utility fluid is steam used in the reboiler with the reboiler duty of $1.222x10^5$ kW.

A comparative study between flue gas recovery and atmospheric recover was performed. The inlet flow rate of gas was held constant as the control variable. In both cases the inlet flowrate is approximately 870,000 kg/hr for atmospheric air or flue gas. The air stream for the atmospheric air was modelled with a carbon dioxide concentration of 0.03 mol%, this is consistent with the average carbon dioxide found in our air (around 400ppm, but modelled as 500ppm). The co2 content in the flue stream was consistent with literature data found with a value of 3.85 mol%. The atmospheric air stream is modelled at ambient temperatures and pressure. A comparison of inlet air streams can be found Table (4) of Appendix (C.). It should be noted that the atmospheric co2 capture model has an air collection system design with three parallel compressors to collect and compress the air. The compressors are followed by aerial coolers that cool the compressed air for effective absorption of co2, as absorption is optimal in high pressures and low temperatures. Three individual inlet streams are independently compressed and cooled. It is designed in this fashion to accommodate for the high gas flow rates. It is impossible to compress and cool the given volume of gas without the temperature being outlandishly high. There for a parallel design is adopted to allow for reasonable temperatures to maintain.

As evident from the inlet stream data it is there is more CO2 to recover from a flue gas recovery system than direct atmospheric recovery. The collection system proves to be extremely expensive, the operating costs high and the co2 recovered very low. A summarized cost, production, and energy comparison is provided in Table (5) of Appendix (C).

Heat Integration

In order to fully optimize the E-100 heat exchanger a pinch analysis was performed. Pinch analysis is a technique to reduce energy consumption and maximize heat recovery.

Currently the inlet hot stream inlet is at 145 °C and outlet at 130.1 °C, the cold stream inlet is at 33.38 °C and outlet at 50 °C. The temperature-enthalpy diagram of this exchange is as attached in figure (8): Appendix(C). As evident, this heat exchange is un-optimized. A pinch analysis study reveals that, that to maximize heat transfer, the hot stream inlet should be at 53 °C and outlet at 38 °C. This is assuming a minimum pinch point temperature differential of 10°C.

Based on Figure [9] in Appendix C, the pinch point position for the hot stream is 50 ^{o}C and for the cold stream, it's 38 ^{o}C. The maximum heat that can be recovered between both streams is 10,691 kW. The cold stream requires an additional 20,300 kW to heat it. A heating utility with an output of 122,000 kW currently being used. The hot stream requires an additional 21,195 kW to cool it. A cooling utility with an output of 210,900 kW is currently being used.

Currently the hot and cold utility are consuming 332,995 kW of energy that can be saved. Implementing this pinch analysis to our process would result in an overall savings of $1582.4 per hour or $13.86 million per year, for the steam utility cost of $\$1.32 \times 10^{-6}$ kJ. As the main operating cost of this design is utility cost, it is imperative that this study be implemented in our design.

Plant Location

The location of our Carbon Capture plant will be in the Athabasca Region, 3 km north of Fort MacKay – a satellite image of the location is provided as Figure (10) of Appendix E. The approximate area of the facility will be 74 acres or (400m × 750m) with the specific Legal Subdivision (LSD) coordinates of (LSD: 13-6-95-10W4). A map view can be seen in Figure (10) of Appendix (E).[16] This is public land in Alberta held by the federal government, thus being subjected to federal and provincial regulations. The relevant federal regulations are the "Federal Real Property and Federal Immovable Act" [17], the "Territorial Lands Act" [18] and the AER have created the Public Lands Act [19]. The sole purpose for these regulatory documents is to ensure that the operations on this public land are carried out in a responsible manner and that work is done closely in conjunction with Alberta Environment and Parks (AEP).

According to the Canadian Association of Petroleum Producers (CAPP), the Alberta oil sands emit 9.8% of all GHG emissions in Canada, which is the main reason why this area was chosen.[20]

Once the bitumen is extracted, it is transported to upgraders where it is upgraded. Upgraders are facilities that upgrade bitumen (or extra heavy oil) into synthetic crude oil. Each barrel of bitumen has roughly 100kg of CO2. There are 5 upgraders in the Fort McMurray Area: Syncrude, Shell, CNRL, Suncor, and Nexen. Totalling up to 1351 M barrels of bitumen produced by all these upgraders per day. This amounts to 135,100 tonnes of CO2 being released as flue gas per day. We aim to capture as much of this CO2 as possible from these upgraders as well as the other facilities in this area.[21]

The geology of this location works well with the storage of CO2. In order for the successful storage of CO2, it must be stored in a permeable formation lying underneath multiple overlying layers of an impermeable formation that can act as a seal, so the CO2 does not escape.

Appendix (E): Figure (11) displays the geology of the Athabasca Oil Sands. [22] The top formations contain unconsolidated materials of sandstone, silt, and shale. Underneath are cretaceous formations, which mostly consist of shale rocks. At the very bottom is the Devonian waterways formation. The Waterways formation is 213m thick of argillaceous limestones. Carbon Dioxide can be stored here since limestone is a permeable rock type, and the upper layer of cretaceous shale formations can act as a proper seal, because of shales' impermeable properties. This makes this location overall the best area for the safe storage of CO2.

With the abundance of gas pipelines in this area, CO2 can also be transported and be used as an artificial lift method in older oil wells or as a commercial product. There is also a lack of competition since there are only 3 carbon capture plants that are currently operating in Alberta, none of which are in this area. [23][7]

Economic Analysis

In order to determine the economic viability of the project, a detailed economic analysis of the project was done using standard conceptual stage techniques. All of the process equipment that was used in our simulations was used to estimate the capital as well as operating cost for the unit. Data from this was then used to determine if the project is to be profitable.

With the nature of the proposed project being one of environmental improvement, the likelihood of being profitable is slim. The viability of the project will be due to government grants as well as cost incentives for the parent plant from carbon tax.

The analysis performed was done over a period of twenty years with a CEPCI of 603.1 [24] for 2018. All prices shown are in USD. Plant location factor was omitted in the analysis shown in Appendix (F) but cost was adjusted within the report and shown in Table (12), Table (13) and Table (16) with a factor of 1.6 for the Fort McMurray location chosen, as Fort McKay is located only about 60 km north of Fort McMurray. [25]

As this is a conceptual phase, the process equipment, sizing and general flowrates may need to be changed as more details of the project come together. This will affect the capital as well as the operating costs.

Capital Cost Estimation

Capital cost at the preliminary stage is a combination of the FCI and the WC. FCI for this project was calculated through Aspen Capital Cost Estimation software using the process equipment and specifications that were simulated in Aspen HYSYS.

The FCI is comprised of ISBL, OSBL, and engineering costs. Costs specific to this project include:[25]

ISBL

- Plant Cost
  - Infrastructure
- Direct Field Cost
  - Equipment
  - Installation
  - Piping
  - Electrical
  - Instrumentation and Controls
- Indirect Field Cost
  - Construction
  - Insurance
  - Labor
  - Misc. Overhead

OSBL

- Additions to Infrastructure
- Power Generation
- Shipping Facilities

Engineering

- Detailed Designs
- Procurement
- Construction Supervision
- Project Management
- Contractors Fees

ASPEN has estimated that the capital cost will be approximately $19,000,000. This is including all of the costs as described above. A contingency factor of 10% was added to the FCI to account for any unforeseen costs that may arise as a result of continued planning. This cost is usually said to be only 10% of the ISBL and OSBL, but as ASPEN has done this estimation, the 10% was taken as the entire FCI just for ease of calculation. This brings the FCI to approximately $21,000,000.

Lastly, there needs to be a working capital cost associated with the initial investment. The working capital, as a rule, needs to be able to cover at least one month of operations. This will include: [25]

- Raw Materials
- Salaries
- Cost of Utilities
- Maintenance Supplies
- Miscellaneous Items

For conceptual phase projects, working capital is generally 10%-20% of the FCI. For this project it has been taken as 15% of the FCI. Working capital was calculated to be just over $3,000,000 for the first year. This working capital was added to the FCI to generate our final value for initial investment. The final capital cost for the project was calculated at just under $24,000,000. [25]

The capital costs estimated for the project was then multiplied by the location factor of 1.6 for Fort McMurray giving us a total just under $38,000,000. [25]

A summary of the above information as well as a detailed account of the capital cost estimation can be found in Appendix (F).

Operating Costs

The operating costs required to extract carbon dioxide from the flue gas and separate it into a pure product involve variable and fixed costs. Feedstocks and utilities are the variable costs in this study. Flue gas from a gas fired plant is obtained at no cost. Using Aspen Process Economic Analyzer, the utilities cost amounted to 51,856,100 USD, as shown in Table (13) of Appendix (F). This relatively high estimate compared to the capital cost resulted from the Rich Amine Desorption column high reboiler duty demand, to maximize the separation of the carbon dioxide from the Rich Amine, a process that is more efficient at temperatures in the range of 127 C to 145 °C. The second highest cost of steam production appeared in the Pumped Rich Amine Heater, which was needed to achieve the required temperature of the rich Amine fed into the desorption column. The 690 kPa steam cost for this Desorption Column Reboiler was 3397.63 USD/hr while the pumped Rich Amine Heater steam cost was 2077.1 USD/hr. The other relatively lower demanding utilities resulted from cooling water used in the condenser desorption column and that being used in cooling the lean amine coming out of the desorption column before being reintroduced back into the absorption column. The cooling water cost for the Desorption Column Condenser and the Lean Amine cooler were 82.40 USD/hr and 285.35 USD/hr, respectively. Freon-12 refrigerant was used to cool the CO2 overhead product out of the Desorption Column at a cost of 57.94 USD/hr. The electricity cost required to pump the evolved Rich Amine from the absorption column was 195.878 USD/hr. The water stream leaving the V-100 Separator as seen in Appendix C, Figure 6 is composed of 99.76 % H_20 and 0.24 % CO2 by mole. Hence, waste water treatment incorporation is not environmentally or commercially required. The total operating labor cost was 657,450 USD/yr while the maintenance cost amounted to 328,725 USD/yr as per Aspen calculations. Table (13) in Appendix (F) summarizes the operating costs incurred using Aspen Economic Analyzer

The depreciable cost for the proposed plant equipment was obtained using the straight line method with a salvage value of 20%, as a fraction of the initial capital cost. The depreciable capital cost of the plant equipment was evaluated at 17.96 MM USD. This results in a salvage value of 3.6MM USD. The annual depreciation based on equation 2 in Appendix H is 1.44 MM USD while the depreciable cost is 14.4 MM USD over a 10-year period. The unit depreciation using equation 3 and based on a production volume of 429,240 metric ton of CO2/yr over a 10-year period resulted in a unit depreciation of 0.00335 USD/kg.

Economic Potential:

To calculate the unit price of production (USD/kg), Equation (6) of Appendix (H) is used. The total operating costs were found to be 57.779 MM USD/yr. The production rate was 48928.5 kg/hr, which amounts to 429,240/ton CO2/yr. Hence the unit production price based on Equation (6) is 138 USD/ton.

The market value of CO2 for enhanced oil recovery is estimated at 50 USD/ton as discussed in the Market Evaluation section. The annual CO2 produced is 429,240 ton/yr. Hence the total annual revenue using Equation (4) in Appendix (H) is 21.462 million USD. The annual income before tax is calculated using Equation (5) in Appendix (H) and amounts to -36,317,000 USD. Hence no tax is applied for this negative value. The resulting economic potential of this project based on 1 Ton of produced carbon dioxide is calculated based on equation 7 and comes out to **be -37.773120 MM USD/yr. The economic potential analysis result is to be expected, as the motive of the plant setup is to focus purely on maximizing the removal of CO2 from flue gas rather than to maximize to the profitability potential.** This proposal is to be funded to achieve the sole aim of mitigating Carbon emissions. What follows is a comparison between using two sources of CO2 and the efficacy when it comes to the efficiency of the removal and the costs incurred. Tables (14) and (15) in Appendix (F) summarize the project profitability including the net earnings cash flow, NPV, IRR, and NRR. Since a negative value of cash flow of approximately -45 MM USD has resulted each year, profitability data cannot be graphed as shown in Table (15) of Appendix (F)

Sensitivity Analysis

To investigate the adaptation ability of the plant setup and operation to differing sources of Feed CO2, using atmospheric air as a source for CO2 removal was investigated as potential scheme. The techno-economic analysis was performed to compare its viability to using flue gas as a source. The preliminary design is simulated in Aspen HYSYS, as shown in Appendix (C), Figure (5) The major design deviations from the flue gas setup involve the requirement of incorporating compressors and subsequent coolers to direct the feed into the absorption column at the required state variables. The coolers are required due to the high temperature of the compressed air which is not favorable for absorption. The rest of the train design is identical to that of the flue gas setup. The capital and operating costs will correspondingly change due to the addition of compressors and the heat duty variations being sensitive to flowrate and composition changes. The capital cost obtained for the atmospheric air run using Aspen Economic Analyzer was 125,075,000 USD while the operating costs were 149,073,000 USD. The capital costs are about 7-fold that of the flue gas run while the operating costs are 3 times that of the flue gas run. The rate of producing dry CO2 1509.3003 kg/h resulting in the production of 130403 Tonne/Yr compared to 429,240 Tonne/Yr produced from flue gas. This agrees with mass transfer principles which favor high concentration gradient for absorption to occur efficiently. With a utility cost of 132,560,000 USD, the cost of production is 1016 USD/Ton. This cost is 10-fold that of the flue gas run which had a 138 USD/Ton production cost. The difference in the rate is due to the concentration of CO2 in atmospheric air being 0.03% by mole based on a concentration 406 ppm in Fort McMurray whereas in the flue gas it was 3.85 % by mole. Therefore, a major contributor to the difference in production rate is the flowrate difference in the feeds, whereby in flue gas 50796 kg/hr of CO2 is being fed to the absorption column while, for the atmospheric air, it amounted to 8662 kg/hr. The flue gas evidently is a more commercially and technically viable source of removing CO2.

Risk Assessment

The risk assessment for a plant at conceptual stage is vital in understanding if the project is worth taking to the next level. By using tools such as a risk matrix, the risks are laid out and easy to understand.

At this level, the risks that are being assessed are quite broad and cover a very wide range of equipment, processes, tasks and finances. For this proposal, the risk assessment has been divided into process hazards, environmental risks and commercial risks. For each of these categories, certain hazards were identified, and a risk level was assigned based on the likelihood of that hazard occurring, as well as what the impact to the project would be if that event actually occurred.

The risk matrix, as seen from Table (20) of Appendix (G), was taken from Project Risk Manager [26] Once the risk level was identified, mitigation strategies were put in place to reduce either the likelihood that the event would occur or to at least reduce the severity. In most cases for this project although the likelihood of the events occurring was reduced, it was found that even with mitigation strategies in place, the impact of these hazards remained quite high.

More precise hazards and mitigation strategies will become apparent at a later stage of production.

Process Hazard Analysis

The process hazard analysis is the portion of this risk assessment that will go through the most changes and will become more up to date as the project progresses. What was found through case studies and research into other types of plants is that there is a huge risk of corrosion and leaking of the chemicals required to perform the process. By implementing standardized operating procedures, maintenance schedules and choosing the right materials for the job, the risks for most of these hazards was reduced from major to moderate. While there are still some hazards that pose a very high risk, these can be maintained by constant assessment and being vigilant.[27]

The process hazard risk assessment can be found in Appendix G Table (17).

Environmental Impact

With this project trying to follow the global millennium challenge and its ultimate goal to reduce a plant’s emissions, the environmental impact was taken very seriously. Most of the hazards mentioned in the environmental impact assessment were of leaking either process fluids or water back into the environment. These fluids can contain contaminants or heat and can also include an increase in the very emissions that we are trying to be contain. By once again ensuring that we have the right materials for the job, working closely with the local and federal environmental groups, installing a water treatment unit, as well as using the existing process and systems that will already be in place at the plant, the risk of these hazards occurring is able to be greatly reduced.

The environmental impact assessment can be found in Appendix (G) Table (18).

Commercial Risk

With the entire project required to be commercially profitable in order to continue operation, the greatest risk lies in this category. The likelihood of these events occurring are generally less than with environmental or the process hazards but have a much greater impact on the project. If there was a breakdown in the financing of the project, it would cease to operate. Mitigation strategies for this category did not seem to do much as the impact remains high. With keeping good communication with plant workers, politicians, and legislative groups, there is a much lower risk of having catastrophic consequences to the project.

The commercial risk assessment can be found in Appendix (G). Table (19).

Conclusions and Recommendations

After a detailed research on Amine Scrubbing, according to our process design and financial analysis we have concluded that performing Amine scrubbing using the gas in the atmosphere is not a feasible idea, economically. However, this project is targeted as a gas waste treatment, and a grant from government would offset the costs incurred. The cost of production for this project is estimated to be at 57M USD/year. This included both the operating cost and the maintenance cost. The revenue calculated was at 21.46M USD/year, resulting in a significant loss. This project is not worth the investment since we are not close to the breakeven point.

Out of all the amines there is, we recommend using MDEA as the primary amine for use because it provides the removal process with the highest treating capacity. Because CO2 gas is considered an acid gas, it is highly toxic and dangerous to us as humans and also to the environment, and it is very important for us to filter out all the CO2 if we want to come close to creating an impact on global warming. Training employees is also recommended to ensure that the proper amount of amine is being used. No excess amines should be used because this can cost us in the long run, due to expenses.

Another recommendation to keep in mind is the energy consumed. This a major factor impacting our cost value. In order to reduce our energy consumption one can install an increment number of trays in both the absorber and the regenerator unit. This can result in a decrease in spending by reducing the reflux ratio which separates the CO2 from the vapour that was injected from the reboiler.

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Appendices

Appendix A - Background Information

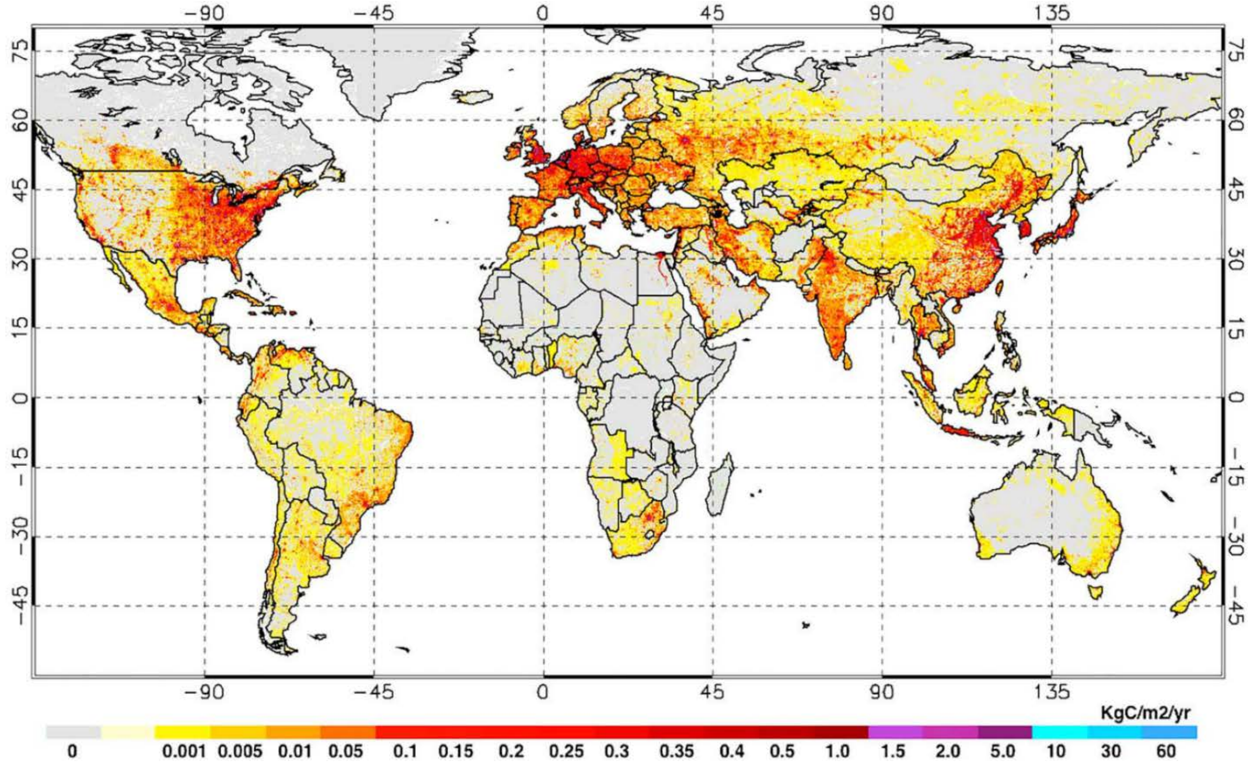

Figure 1: Total Carbon Dioxide Emissions from Fossil Fuels in 2010

[2]

Appendix B – Case Study

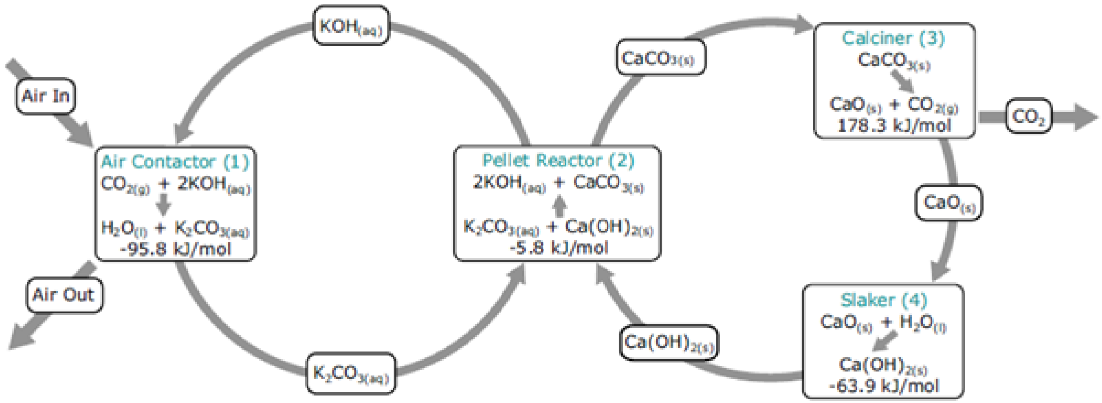

Figure 2: Process Chemistry Loop for Carbon Engineering DAC Pilot Plant

[10]

Table 1: Project Operating Costs of the Quest CCS Facility

[11]

Cost Category	Oct 1, 2015 – Dec 31, 2016	2017 Jan 1 – Dec 31
Power	3,717.70	4,513.96
Steam	8,414.46	8,834.50
Compressed Air	67.67	62.59
Cooling Water	427.95	389.81
Direct Labour and Personnel Costs	7,829.42	5,635.83
Maintenance Materials and Technical Services	969.42	942.63
Property Tax	2,003.72	2,000.28
Sequestration Opex	7,052.85	6,797.59
MMV after Operations	1,690.41	1,655.74
Post Closure Stewardship Fund	272.07	264.28
Other Well Costs	431.49	442.12
Subsurface Tenure Costs	362.50	420.00
Pipeline - Inspection and Pigging	145.78	340.49
Amine	340.67	0.00
Chemicals	20.35	97.92
Vendor rebates	-122.32	-100.36
Corporate and Other Costs	119.24	205.95
Total	33,743.37	32,503.34

Appendix C – Process Design Tables and Figures

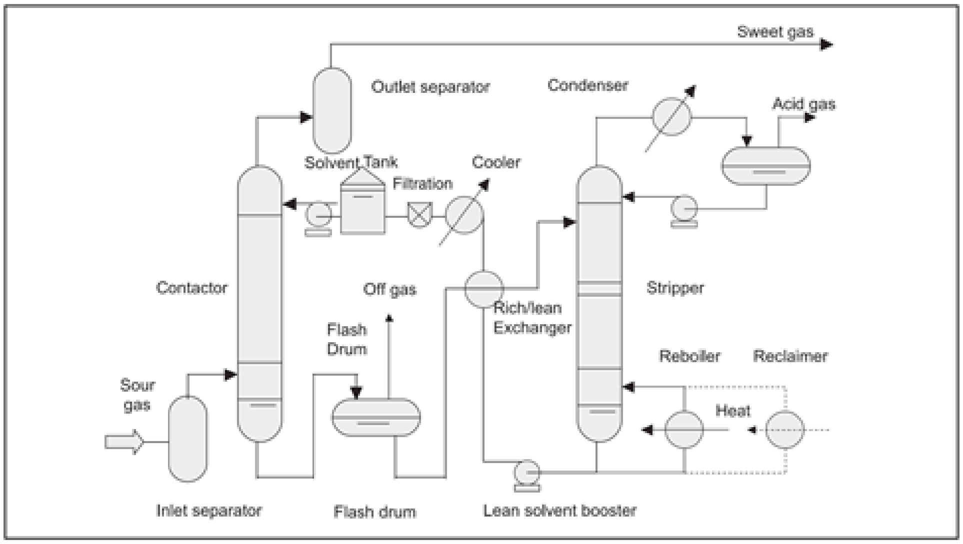

Figure 3: General Process Flow Diagram as Described by the GPSA [14]

Table 2: Inlet and Outlet Mass Flowrates

Inlet Material Stream	Mass Flow (kg/hr)	Outlet Material Stream	Mass Flow (kg/hr)
Collected Flue Gas	880789	Air	842914
Makeup Water	32884	Water	6939
Total Mass In	913673	Dry CO2	48909
		Total Mass Out	898762

Table 3: Inlet and Outlets Energy Flow rates

Inlet Stream	Energy Flow (kJ/hr)	Outlet Stream	Energy Flow (kJ/hr)
Collected Flue Gas	260,728,802	Air	255,968,224
Pump Energy	661,751	Condenser Energy	63,843,332
Reboiler Energy	430,231,789	Cooler Energy	759,156,208
Make up Water	62,255,802	Water	13,193,566
Heater Energy	439,788,699	Dry CO2	10,245,676
		CO2 Cooler	21,507,579
Total	1,069,155,238	Total	1,097,527,453

Table 4: Data Regarding the Flue and Atmospheric Models

	Flue Gas Stream	**Collected Atmospheric Air**	Individual Inlet stream
Pressure (kPa)	25	30	25
Temperature (°C)	200	260	98
Overall Molar Flow (kmol/h)	30,000	30,000	10000
Overall Mass Flow (kg/h)	880,800	863,000	288,000
CO2 Molar Flow (kmol/h)	1,154.2	9.903	3.301
CO2 Mass Flow (kg/h)	50,796.5	435.8	145.3
CO2 Mol Frac	0.0385	0.003	0.003
CO2 Mass Frac	0.0577	0.005	0.005

Table 5: Comparison Between Atmospheric and Flue Gas Model

	Atmospheric Model	Flue Gas Model
Inlet Gas Mass (kg/h)	863,000	880,800
Carbon Dioxide Produced (kg/h)	740.2	48,910
Removal efficiency	0.839	0.963
Reboiler energy per kg CO2 (MJ/kg)	2,400	8.8
Capital Cost (USD)	125,075,000 USD	20,234,900
Operating Cost(USD)	149,073,000 USD	57,779,700

Equation 1: Sample Calculations Regarding Process Design

Calculation of Amine Required:

Lean Amine Gas Loading (residual CO2): $\frac{0.025 \text{ mol CO2}}{\text{mol MEA}}$

Maximum Rich Amine Gas Loading: $\frac{0.5 \text{ mol CO2}}{\text{mol MEA}}$

MEA Solution (wt%): 0.28 MEA (0.0625 mol frac), 0.72 H2O

Inlet CO2: 1154 kmol/h

$$\text{MEA required: } \frac{1154 \text{kmol CO2}}{(0.5-0.025)\text{kmol CO2}/\text{kmol MEA}} = 2429.4 \text{ kmol MEA}$$

$$\text{Solution Required: } \frac{2429.4 \text{ kmol MEA}}{0.0625} = 38,872 \text{ kmol}$$

CO$_2$ Recovery from Flue Gas Through Amine Scrubbing

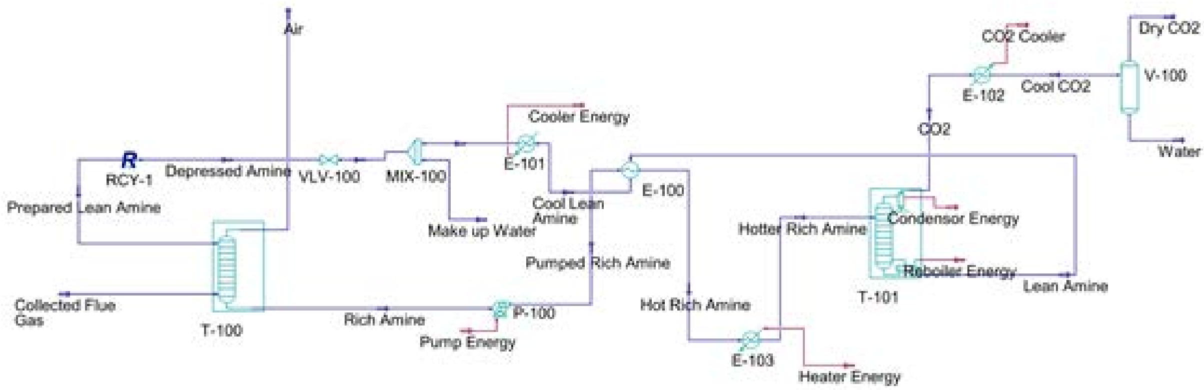

Figure 4: PFD of Amine Scrubbing Process

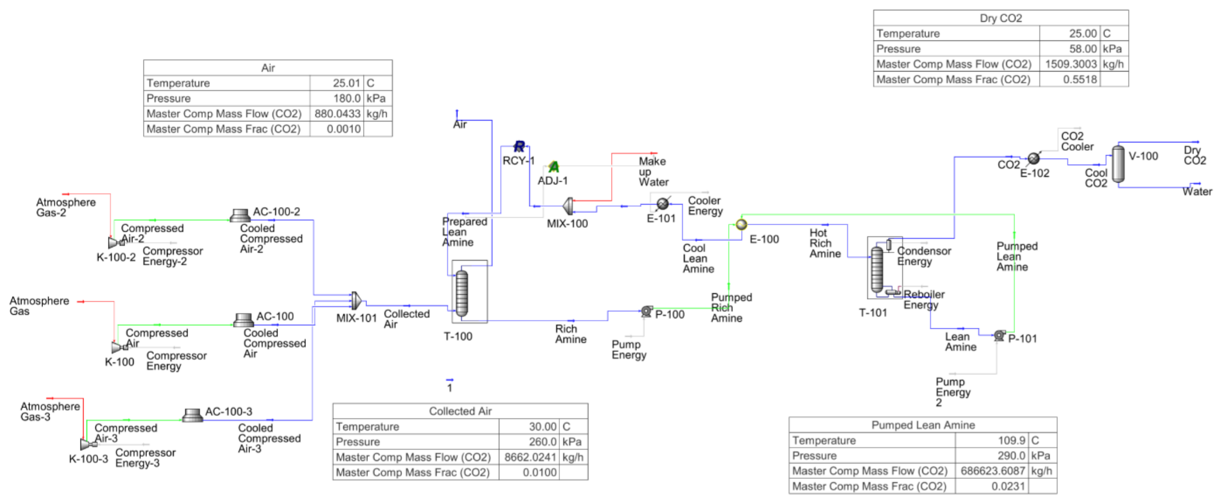

Figure 5: HYSYS Simulation Run and Stream Data for Flue Gas

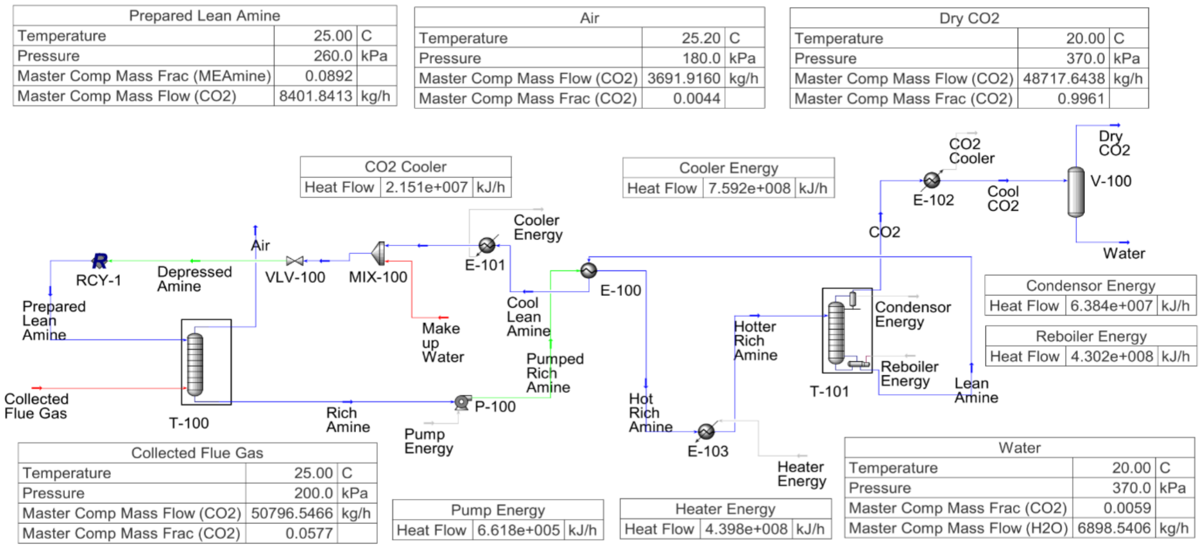

Figure 6: HYSYS Simulation Run and Stream Data for Flue Gas

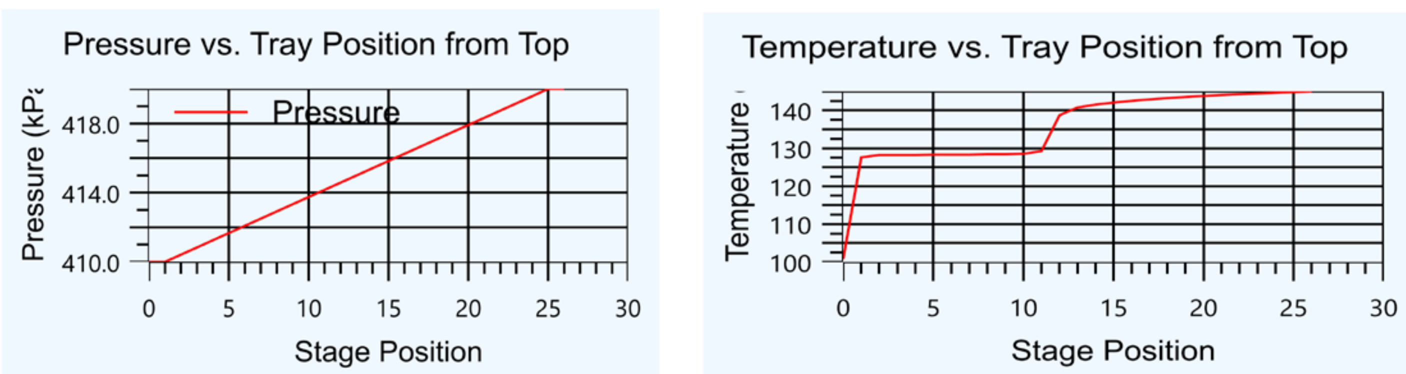

Figure 7: Variation of Pressure and Temperature with Tray Position for Desorber Column

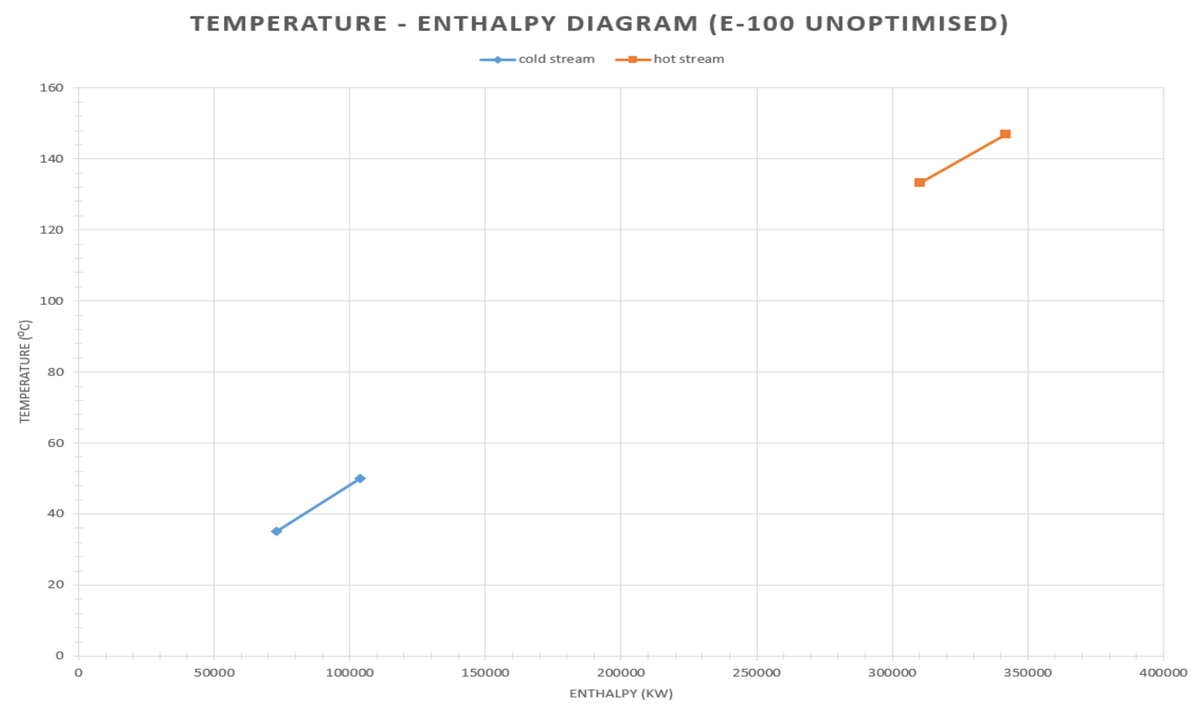

Figure 8: Un-optimised E-100 Heat Exchanger

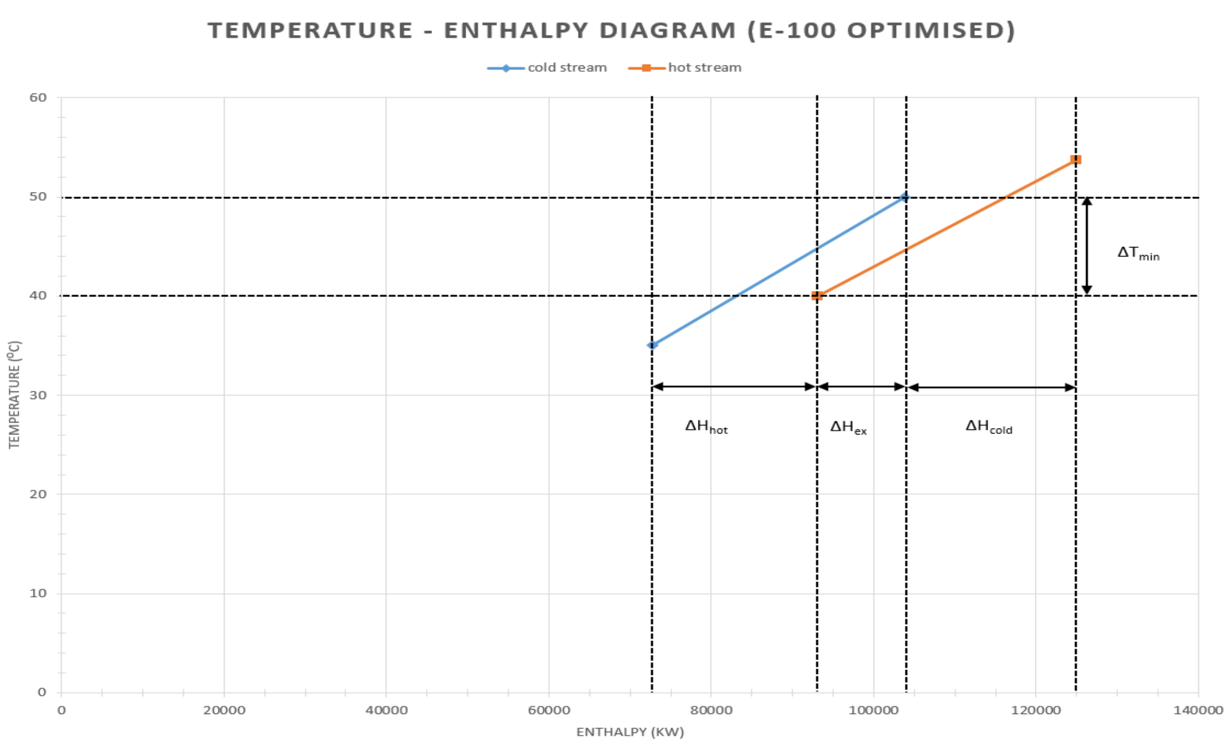

Figure 9: Optimised E-100 Heat Exchanger

Table 6: Information about Items, Rates, Operating Pressure and Temperature

Fluid	Item Description	Rate	Rate Units	Cost per Hour (USD)	Operating Pressure (kPa)	Operating Temperature (°C)
Water	E-101	9001.7	M3/H	$ 285.35	345	35
Water	T-101-Main TS-cond	2599.4	M3/H	$ 82.40	345	35
Refrigerant	E-102	340.8	TON/H	$ 57.94	105	-29.8
Steam	T-101-Main TS-reb	189.7	TON/H	$ 3,397.63	689.5	164.3
Steam	E-103	115.9	TON/H	$ 2,077.09	689.5	164.3
Electricity		195.97	KW	$ 15.18	-	-

Appendix D - Equipment Specifications

Table 7: Absorber and Desorber Conditions and Sizing Specifications

Equipment	DTW TRAYED T-100-TS-1-tower (Absorber)	DTW TRAYED T-101-Main TS-tower (Desorber)
Tray type	SIEVE	SIEVE
Vessel Diameter (m)	10.05	5.18
Vessel tangent to tangent height (m)	12.34	20.26
Design gauge pressure (KPa)	243.67	488.67
Design Temperature C	125.00	176.23
Operating Temperature C	52.06	146.23
Number of Trays	25	25
Tray spacing (cm)	609.60	609.60
Molecular weight overhead product	29.36	22.66

Table 8: Desorber Reflux Condenser Sizing Specifications

Equipment	DHT HORIZ DRUMT-101-Main TS-condenser/ accumulator
Liquid Volume (m3)	6.31
Vessel diameter (m)	1.37
Vessel Tangent to Tangent Length (m)	4.27
Design gauge pressure (kPa)	478.67
Design Temperature (Deg. C))	153.76
Operating Temperature (Deg. C)	123.76

Table 9: Desorber Reboiler Conditions and Sizing Specifications

Equipment	DRB U TUBE T-101-Main TS-reboiler
Number of identical items	1.00
Heat transfer area [M2]	5616.48
Tube design gauge pressure [KPAG]	758.17
Tube design temperature [DEG C]	194.30
Tube operating temperature [DEG C]	164.30
Tube outside diameter [MM]	25.40
Shell design gauge pressure [KPAG]	488.67
Shell design temperature [DEG C]	176.92
Shell operating temperature [DEG C]	146.92
Tube length extended [M]	6.10
Tube pitch [MM]	31.75
Tube pitch symbol	TRIANGULAR
Number of tube passes	2.00
Duty [MEGAW]	108.93
TEMA type	BKU

Table 10: Desorber Reflux Pump Efficiency and Specifications

Equipment	DCP CENTRIF T-101-Main TS-reflux pump
Liquid flow rate [L/S]	17.57
Fluid specific gravity	0.94
Design gauge pressure [KPAG]	478.67
Design temperature [DEG C]	153.41
Fluid viscosity [MPA-S]	0.50
Pump efficiency [PERCENT]	70.00

Table 11: Desorber Heat Exchanger Specifications and Design Conditions

Equipment	DHE TEMA EXCH T-101-Main TS-cond
Number of identical items	1.00
Heat transfer area [M2]	455.45
Front end TEMA symbol	B
Shell TEMA symbol	E
Rear end TEMA symbol	M
Tube design gauge pressure [KPAG]	413.67
Tube design temperature [DEG C]	166.58
Tube operating temperature [DEG C]	35.00
Tube outside diameter [MM]	25.40
Shell design gauge pressure [KPAG]	478.67
Shell design temperature [DEG C]	166.58
Shell operating temperature [DEG C]	136.58
Tube length extended [M]	6.10
Tube pitch [MM]	31.75
Number of tube passes	1.00
Number of shell passes	1.00

Table 12: Process Heater/Cooler Specifications and Design Conditions

Equipment	DHE TEMA EXCH E-100	DHE TEMA EXCH E-101	DHE TEMA EXCH E-102	DHE TEMA EXCH E-103
Number of identical items	1.00	1.00	1.00	1.00
Heat transfer area [M2]	150.80	7081.81	269.33	663.20
Front end TEMA symbol	B	B	B	B
Shell TEMA symbol	E	E	E	E
Rear end TEMA symbol	M	M	M	M
Tube design gauge pressure [KPAG]	568.67	413.67	285.34	758.17
Tube design temperature [DEG C]	176.92	163.21	153.76	194.30
Tube operating temperature [DEG C]	50.00	35.00	-29.80	164.30
Tube outside diameter [MM]	25.40	25.40	25.40	25.40
Shell design gauge pressure [KPAG]	488.67	448.67	478.67	528.67
Shell design temperature [DEG C]	176.92	163.22	153.76	140.00
Shell operating temperature [DEG C]	146.92	133.22	123.76	110.00
Tube length extended [M]	6.10	6.10	6.10	6.10
Tube pitch [MM]	31.75	31.75	31.75	31.75
Number of tube passes	1.00	1.00	1.00	1.00
Number of shell passes	1.00	1.00	1.00	1.00

Table 13: CO2 Final Separator Design Specifications and Operating Conditions

Equipment	DVT CYLINDER V-100
Liquid volume [M3]	5.85
Vessel diameter [M]	1.37
Vessel tangent to tangent height [M]	3.96
Design gauge pressure [KPAG]	438.67
Design temperature [DEG C]	22.00
Operating temperature [DEG C]	20.00

Appendix E – Plant Location Figures

Figure 10: Plant Location Near Fort Mackay

[16]

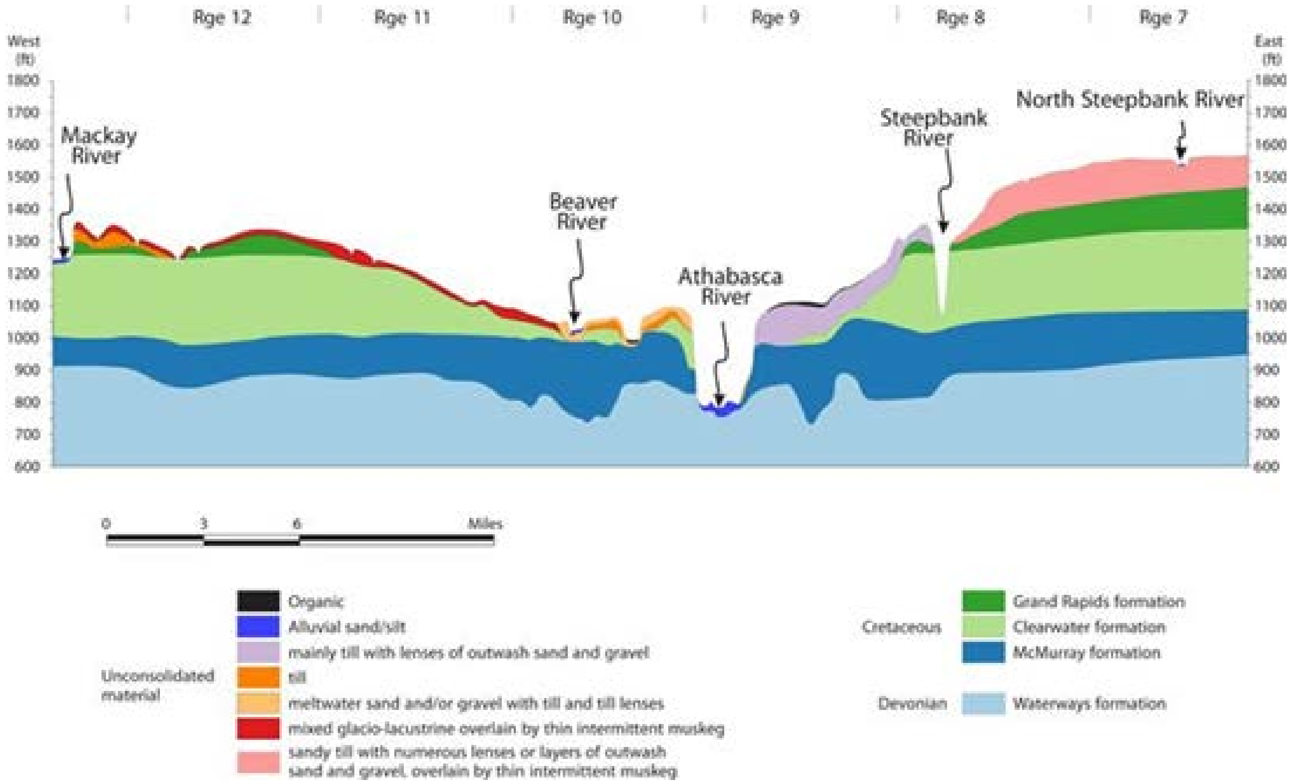

Figure 11: Geological Formations of the Athabasca Oil Sands Region

[18]

Appendix F – Cost Analysis

Table 14: Summary of Project Capital Cost

PROJECT CAPITAL SUMMARY		TOTAL COST	
Purchased Equipment	Cost	$	5,512,600.00
Equipment Setting	Cost	$	103,026.00
Piping	Cost	$	2,944,350.00
Civil	Cost	$	432,385.00
Steel	Cost	$	105,401.00
Instrumentation	Cost	$	794,820.00
Electrical	Cost	$	683,159.00
Insulation	Cost	$	329,578.00
Paint	Cost	$	97,161.70
Other	Cost	$	5,075,400.00
Subcontracts	Cost	$	-
G and A Overheads	Cost	$	420,662.00
Contract Fee	Cost	$	649,705.00
Escalation	Cost	$	-
Contingencies	Cost	$	3,086,680.00
Total Project Cost	Cost	$	20,234,900.00
Adjusted Total Project Cost	Cost	$	17,958,500.00

Table 15: Summary of Operating Costs

OPERATING COST RESULTS SUMMARY			
Total Operating Labor and	Cost/Year	$	986,175.00
Total Utilities Cost	Cost/Year	$	51,856,100.00
Total Operating Cost	Cost/Year	$	57,779,700.00
Operating Labor Cost	Cost/Year	$	657,450.00
Maintenance Cost	Cost/Year	$	328,725.00
Operating Charges	Cost/Year	$	164,363.00
Plant Overhead	Cost/Year	$	493,088.00
Subtotal Operating Cost	Cost/Year	$	53,499,700.00
G and A Cost		$	4,279,980.00

Table 16: Net Cash flow Analysis for The First Five Years

		Year 1	Year 2	Year 3	Year 4	Year 5
R (Revenue)	**Cost/Period**	$ (45,095,700)	$ (42,613,200)	$ (43,517,900)	$ (44,431,100)	$ (45,352,000)
DEP (Depreciation Expense)	Cost/Period	$ 1,436,680	$ 1,436,680	$ 1,436,680	$ 1,436,680	$ 1,436,680
E (Earnings Before Taxes)	Cost/Period	$ (46,532,400)	$ (44,049,900)	$ (44,954,600)	$ (45,867,800)	$ (46,788,700)
TAX (Taxes)	Cost/Period	$ -	$ -	$ -	$ -	$ -
NE (Net Earnings)	Cost/Period	$ (46,532,400)	$ (44,049,900)	$ (44,954,600)	$ (45,867,800)	$ (46,788,700)
TED (Total Earnings)	Cost/Period	$ (45,095,700)	$ (42,613,200)	$ (43,517,900)	$ (44,431,100)	$ (45,352,000)
TEX (Total Expenses (Excludes Taxes and Depreciation)	Cost/Period	$ 46,122,400	$ 61,298,500	$ 63,137,500	$ 65,031,600	$ 66,982,500
CF (CashFlow for Project)	Cost/Period	$ (45,095,700)	$ (42,613,200)	$ (43,517,900)	$ (44,431,100)	$ (45,352,000)

Table 17: Profitability Indicators for the First Five Years

		Year 1	Year 2	Year 3	Year 4	Year 5
NPV (Net Present Value)	Cost/Year	$ -	$ (37,579,700.00)	$ (67,172,300.00)	$ (92,356,300.00)	$ (113,783,000.00)
IRR (Internal Rate of Return)	Percent	$ -	N/A	N/A	N/A	N/A
MIRR (Modified Internal Rate of Return)	Percent	$ 5.63	N/A	N/A	N/A	N/A
NRR (Net Return Rate)	Percent	$ (71.79)	N/A	N/A	N/A	N/A
PO (Payout Period)	Period	$ -	N/A	N/A	N/A	N/A
ARR (Accounting Rate of Return)	Percent	$ (441.91)	N/A	N/A	N/A	N/A
PI (Profitability Index)		$ 0.28	N/A	N/A	N/A	N/A

Table 18: Capital Cost Estimation

Item	**Cost**
Cumulative Capital Cost	$18,856,400.00
Capital Cost With Contingency	$20,742,040.00
Working Capital	$3,111,306.00
CAP (Capital Costs)	$23,853,346.00
Capital Cost Adjusted for Fort McMurray	$38,165,353.60

Appendix G – Risk Analysis

Table 19: Process Hazards

						After Mitigation		
Hazard	**Description**	**Probability**	**Impact**	**Risk**	**Possible Mitigation**	**Probability**	**Impact**	**Risk**
Material Corrosion	Corrosion from improper absorber, pump, and valve material.	Probable	High	16 - Major	Chosing the right material for the job and following a strict inspection schedule	Possible	High	12 - Major
Amine Degradation	CO2 being present in amine at a temperature above 100°C can cause carbamate polymerization, the most common cause of amine degradation.	Highly Probable	Low	10 - Major	Testing the amine for qualiy and replacing it according to a schedule.	Possible	Low	6 - Moderate
No Flow Into the system	No flowrate into the system of either flue gas or amine caused by blockages, human error, or equipment failure.	Possible	Medium	9 - Moderate	Monitoring when the parent plant is shut down or when flow is reduced to react and shut the sweetening unit down.	Unlikely	Medium	6 - Moderate
Loss of Solvent/Flue Gas	Due to pipeline leakages and improper seals on equipment and valves.	Unlikely	Medium	6 - Moderate	Monitoring and maintaining all connection points (valves, fittings etc.	Possible	Medium	9 - Moderate
Overflow	Similar to no flow. Too much amine flow caused by human error or malfunctioning valves or pumps.	Possible	High	12 - Major	Having automated systems and level controllers in place to act as a backup.	Unlikely	High	8 - Moderate
Pressure Increases	Usually due to too much flue gas flow with an obstrucion in the gas outlet, causing an accumulation of gas in the system.	Possible	Very High	15 - Major	Pressure alarms and release valves in place throughout the system to automatically reduce pressure until the issue is resolved.	Unlikely	Very High	10 - Major
Change in Flue Gas Composition	Can be due to corrosion in the pipelines, but can be due to different combustion materials present.	Highly Probable	Low	10 - Major	Adjusting amine flowrate to accommodate.	Possible	Low	6 - Moderate

Table 20: Environmental Hazards

						After Mitigation		
Hazard	**Description**	**Probability**	**Impact**	**Risk**	**Possible Mitigation**	**Probability**	**Impact**	**Risk**
Amine Leakage	Amine leaking from vessels, corroded pipes, or valves into the outside invironment	Possible	High	12 - Major	Monitoring corrosion, valves and fittings, and doing equipment checks	Unlikely	High	8 - Moderate
Increased Emissions from Scrubbing Unit	Combustion process from the reboiler or heater may cause additional emissions if not closely monitored or combusting the material completely. Amine, CO2, CO, Nox, Sox	Possible	Medium	9 - Moderate	If an increase in emissions is detected through installed monitors, production will be slowed/stopped until the problem is recitfied.	Unlikely	Medium	6 - Moderate
Demolishment of Ecosystems	Due to the placement of the plant, as well as activity in the surrounding areas.	Possible	High	12 - Major	Building onto an existing plant will reduce the risk of demolishing an ecosystem	Rare	High	4 - Moderate
Contaminated Wastewater being released into environment	Wastewater from heat exchangers contaminated with chemicals, or heat being released to environment.	Probable	High	16 - Major	Water contaminated with chemicals/heat can be treated before release back into the environment.	Rare	High	4 - Moderate

Table 21: Commercial Risks

						After Mitigation		
Hazard	**Description**	**Probability**	**Impact**	**Risk**	**Possible Mitigation**	**Probability**	**Impact**	**Risk**
Existing Plant with out of Date Technology	The existing plant that is being built upon may have technology that is not compatible for flue gas capture	Possible	High	12 - Major	Taking stock of everything in the existng plant and retrofitting the parts that require update	Rare	High	4 - Moderate
No Room for Required Equipment	The equipment required for flue gas capture and sweetening may not fit in the already exisiting plant design	Possible	High	12 - Major	looking at schematics to see what can be moved or where new equipment can be placed	Unlikely	High	8 - Moderate
Timing	Project not following schedule may cause financial setbacks	Highly Probable	Medium	15 - Major	Daily/Weekly meetings and deadlines to stay on track for completion	Probable	Medium	12 - Major
Permits	Possibility of not getting required permits to build	Unlikely	Very High	10 - Major	Meeting with proper government agencies and poloticians to ensure that all legislation is being met	Rare	Very High	5 - Moderate
No Return on Investment	New plant may take longer than expected to turn a profit	Possible	Very High	15 - Major	By staying on track with other miigation strategies the likelihood of a return on investment is higher.	Unlikely	Very High	10 - Major

Table 22: Qualitative Risk Matrix

[22]

5x5 RISK MATRIX

PROBABILITY					
Highly Probable	5 Moderate	10 Major	15 Major	20 Severe	25 Severe
Probable	4 Moderate	8 Moderate	12 Major	16 Major	20 Severe
Possible	3 Minor	6 Moderate	9 Moderate	12 Major	15 Major
Unlikely	2 Minor	4 Moderate	6 Moderate	8 Moderate	10 Major
Rare	1 Minor	2 Minor	3 Minor	4 Moderate	5 Moderate
	Very Low	Low	Medium	High	Very High

IMPACT

Appendix H – Economical Analysis Calculations

Equation 2: Annual Deprecation Cost

$$Annual\ Depreciation\ Cost\left(\frac{USD}{yr}\right) = \frac{Depreciable\ Capital\ Cost(USD)}{10yr}$$

$$Annual\ Depreciation\ Cost\left(\frac{USD}{yr}\right) = \frac{14.4*10^6\ USD}{10yr} = 1.44\ \text{million USD}$$

Equation 3: Unit Depreciation

$$Unit\ Depreciation\ (USD/kg) = \frac{Depreciable\ Capital\ Cost(USD)}{(10yr)(Production\ Volume(\frac{Kg}{yr})}$$

$$Unit\ Depreciation\ (USD/kg) = \frac{14.4*10^6\ USD}{(10yr)(429240000\left(\frac{Kg}{yr}\right))} = 0.00335\ USD/kg$$

Equation 4: Total Revenue

$$Total\ Revenue\ (USD/kg) = Unit\ Price(USD) * Quantity\ of\ products\ Products\ Produced$$

$$Total\ Revenue\ (USD/yr) = 50(USD/Ton) * 429240\frac{Ton}{yr} = 21{,}462000\ USD$$

Equation 5: Annual Income Before Tax

$$Annual\ Income\ Before\ Tax = Revenue - \ (Fixed\ Operating\ Costs + Variable\ Operating\ Costs$$

$$Annual\ Income\ Before\ Tax = 21{,}462000\ USD - 57{,}779{,}000 = -36{,}317{,}000\ USD$$

Equation 6: Product Cost

$$Product\ Cost\ (USD/kg) = \frac{Operating\ Costs(\frac{USD}{yr}) + CCA}{(Production\ Rate\left(\frac{Kg}{yr}\right))}$$

$$Product\ Cost\ (USD/kg) = \frac{57.779*10^6\left(\frac{USD}{yr}\right) + 1{,}436680\left(\frac{USD}{yr}\right)}{(429{,}240000\left(\frac{Kg}{yr}\right))} = 0.138\ USD/kg = 138\ USD/ton$$

Equation 7: Economic Potential

$$Economic\ Potential = Sales\ Revenue - Cost\ of\ Feedstocks$$

$$Economic\ Potential = 21.462 * 10^6 \left(\frac{USD}{yr}\right) - \left(138\ \frac{USD}{Ton}\right) * \left(429{,}240 \frac{Ton}{yr}\right) = -37{,}773120\ \text{USD/yr.}$$

Appendix I – Condensed Full Report

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:57:56 2019

Workbook: Case (Main)

Material Streams

Fluid Pkg: All

Name		Rich Amine	Air	Pumped Rich Amine	Hot Rich Amine	CO2
Vapour Fraction		0.0000	1.0000	0.0000	0.0000	1.0000
Temperature	(C)	33.29	25.20	33.38	50.00 *	100.8
Pressure	(kPa)	200.0	180.0	500.0 *	460.0	410.0
Molar Flow	(kgmole/h)	8.896e+004	2.944e+004	8.896e+004	8.896e+004	1500
Mass Flow	(kg/h)	1.743e+006	8.429e+005	1.743e+006	1.743e+006	5.585e+004
Liquid Volume Flow	(m3/h)	1755	979.4	1755	1755	66.19
Heat Flow	(kJ/h)	-2.880e+009	2.560e+008	-2.880e+009	-2.764e+009	1.856e+007
Name		Cool Lean Amine	Prepared Lean Amine	Lean Amine	Cold Lean Amine	Mixed Amine
Vapour Fraction		0.0000	0.0000	0.0000	0.0000	0.0000
Temperature	(C)	130.1	25.00 *	145.0	25.00 *	25.00
Pressure	(kPa)	380.0	260.0 *	420.0	340.0	340.0
Molar Flow	(kgmole/h)	8.746e+004	8.840e+004 *	8.746e+004	8.746e+004	8.929e+004
Mass Flow	(kg/h)	1.687e+006	1.705e+006	1.687e+006	1.687e+006	1.720e+006
Liquid Volume Flow	(m3/h)	1689	1707	1689	1689	1722
Heat Flow	(kJ/h)	-2.092e+009	-2.885e+009	-1.976e+009	-2.851e+009	-2.914e+009
Name		Make up Water	Dry CO2	Water	Cool CO2	Collected Flue Gas
Vapour Fraction		0.0000	1.0000	0.0000	0.7441	1.0000
Temperature	(C)	25.00 *	20.00	20.00	20.00 *	25.00 *
Pressure	(kPa)	370.0 *	370.0	370.0	370.0	200.0 *
Molar Flow	(kgmole/h)	1825	1116	383.9	1500	3.000e+004 *
Mass Flow	(kg/h)	3.288e+004 *	4.891e+004	6939	5.585e+004	8.808e+005
Liquid Volume Flow	(m3/h)	32.95	59.23	6.962	66.19	1027
Heat Flow	(kJ/h)	-6.226e+007	1.025e+007	-1.319e+007	-2.948e+006	2.607e+008
Name		Hotter Rich Amine	Depressed Amine			
Vapour Fraction		0.0001	0.0000			
Temperature	(C)	110.0 *	25.00			
Pressure	(kPa)	420.0	260.0 *			
Molar Flow	(kgmole/h)	8.896e+004	8.929e+004			
Mass Flow	(kg/h)	1.743e+006	1.720e+006			
Liquid Volume Flow	(m3/h)	1755	1722			
Heat Flow	(kJ/h)	-2.324e+009	-2.914e+009			

Compositions

Fluid Pkg: All

Name	Rich Amine	Air	Pumped Rich Amine	Hot Rich Amine	CO2
Comp Mole Frac (Oxygen)	0.0000	0.1868	0.0000	0.0000	0.0004
Comp Mole Frac (MEAmine)	0.0280	0.0000	0.0280	0.0280	0.0000
Comp Mole Frac (H2O)	0.9578	0.0175	0.9578	0.9578	0.2601
Comp Mole Frac (CO2)	0.0142	0.0028	0.0142	0.0142	0.7385
Comp Mole Frac (Nitrogen)	0.0000	0.7928	0.0000	0.0000	0.0009
Name	Cool Lean Amine	Prepared Lean Amine	Lean Amine	Cold Lean Amine	Mixed Amine
Comp Mole Frac (Oxygen)	0.0000	0.0000 *	0.0000	0.0000	0.0000
Comp Mole Frac (MEAmine)	0.0285	0.0282 *	0.0285	0.0285	0.0279
Comp Mole Frac (H2O)	0.9698	0.9697 *	0.9698	0.9698	0.9704
Comp Mole Frac (CO2)	0.0018	0.0022 *	0.0018	0.0018	0.0017
Comp Mole Frac (Nitrogen)	0.0000	0.0000 *	0.0000	0.0000	0.0000
Name	Make up Water	Dry CO2	Water	Cool CO2	Collected Flue Gas
Comp Mole Frac (Oxygen)	0.0000 *	0.0006	0.0000	0.0004	0.1834 *
Comp Mole Frac (MEAmine)	0.0000 *	0.0000	0.0000	0.0000	0.0000 *
Comp Mole Frac (H2O)	1.0000 *	0.0066	0.9976	0.2601	0.0000 *
Comp Mole Frac (CO2)	0.0000 *	0.9916	0.0024	0.7385	0.0385 *
Comp Mole Frac (Nitrogen)	0.0000 *	0.0012	0.0000	0.0009	0.7781 *

LEGENDS Burlington, MA USA	
Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
Unit Set:	SI
Date/Time:	Thu Apr 04 21:57:56 2019

Workbook: Case (Main) (continued)

Compositions (continued)

Fluid Pkg: All

Name	Hotter Rich Amine	Depressed Amine			
Comp Mole Frac (Oxygen)	0.0000	0.0000			
Comp Mole Frac (MEAmine)	0.0280	0.0279			
Comp Mole Frac (H2O)	0.9578	0.9704			
Comp Mole Frac (CO2)	0.0142	0.0017			
Comp Mole Frac (Nitrogen)	0.0000	0.0000			

Energy Streams

Fluid Pkg: All

Name		Pump Energy	Condensor Energy	Reboiler Energy	Cooler Energy	CO2 Cooler
Heat Flow	(kJ/h)	6.618e+005	6.384e+007	4.302e+008	7.592e+008	2.151e+007
Name		Heater Energy				
Heat Flow	(kJ/h)	4.398e+008				

Unit Ops

Operation Name	Operation Type	Feeds	Products	Ignored	Calc Level
T-100	Absorber	Prepared Lean Amine Collected Flue Gas	Rich Amine Air	No	2500 *
E-100	Heat Exchanger	Pumped Rich Amine Lean Amine	Hot Rich Amine Cool Lean Amine	No	500.0 *
P-100	Pump	Rich Amine Pump Energy	Pumped Rich Amine	No	500.0 *
T-101	Distillation	Hotter Rich Amine Reboiler Energy	Lean Amine CO2 Condensor Energy	No	2500 *
E-101	Cooler	Cool Lean Amine	Cold Lean Amine Cooler Energy	No	500.0 *
E-102	Cooler	CO2	Cool CO2 CO2 Cooler	No	500.0 *
MIX-100	Mixer	Cold Lean Amine Make up Water	Mixed Amine	No	500.0 *
V-100	Separator	Cool CO2	Water Dry CO2	No	500.0 *
E-103	Heater	Hot Rich Amine Heater Energy	Hotter Rich Amine	No	500.0 *
RCY-1	Recycle	Depressed Amine	Prepared Lean Amine	No	3500 *
VLV-100	Valve	Mixed Amine	Depressed Amine	No	500.0 *

Appendix I – Full Material and Energy Report

LEGENDS
Burlington, MA
USA

Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
Unit Set:	SI
Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Rich Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	33.29	33.29			
Pressure:	(kPa)	200.0	200.0			
Molar Flow	(kgmole/h)	8.896e+004	8.896e+004			
Mass Flow	(kg/h)	1.743e+006	1.743e+006			
Std Ideal Liq Vol Flow	(m3/h)	1755	1755			
Molar Enthalpy	(kJ/kgmole)	-3.238e+004	-3.238e+004			
Molar Entropy	(kJ/kgmole-C)	77.49	77.49			
Heat Flow	(kJ/h)	-2.880e+009	-2.880e+009			
Liq Vol Flow @Std Cond	(m3/h)	1648 *	1648			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

Material Stream: Air

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase			
Vapour / Phase Fraction		1.0000	1.0000			
Temperature:	(C)	25.20	25.20			
Pressure:	(kPa)	180.0	180.0			
Molar Flow	(kgmole/h)	2.944e+004	2.944e+004			
Mass Flow	(kg/h)	8.429e+005	8.429e+005			
Std Ideal Liq Vol Flow	(m3/h)	979.4	979.4			
Molar Enthalpy	(kJ/kgmole)	8694	8694			
Molar Entropy	(kJ/kgmole-C)	186.5	186.5			
Heat Flow	(kJ/h)	2.560e+008	2.560e+008			
Liq Vol Flow @Std Cond	(m3/h)	---	---			

 * Specified by user.

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Air (continued)

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

COMPOSITION

Overall Phase

Vapour Fraction 1.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	5501.2190	0.1868	176039.0067	0.2088	154.7351	0.1580
MEAmine	0.2335	0.0000	14.2620	0.0000	0.0140	0.0000
H2O	514.7610	0.0175	9273.4708	0.0110	9.2922	0.0095
CO2	83.8887	0.0028	3691.9160	0.0044	4.4732	0.0046
Nitrogen	23342.5594	0.7928	653895.1280	0.7758	810.9080	0.8279
Total	29442.6615	1.0000	842913.7835	1.0000	979.4225	1.0000

Vapour Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	5501.2190	0.1868	176039.0067	0.2088	154.7351	0.1580
MEAmine	0.2335	0.0000	14.2620	0.0000	0.0140	0.0000
H2O	514.7610	0.0175	9273.4708	0.0110	9.2922	0.0095
CO2	83.8887	0.0028	3691.9160	0.0044	4.4732	0.0046
Nitrogen	23342.5594	0.7928	653895.1280	0.7758	810.9080	0.8279
Total	29442.6615	1.0000	842913.7835	1.0000	979.4225	1.0000

Material Stream: Pumped Rich Amine

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	33.38	33.38			
Pressure:	(kPa)	500.0 *	500.0			
Molar Flow	(kgmole/h)	8.896e+004	8.896e+004			
Mass Flow	(kg/h)	1.743e+006	1.743e+006			
Std Ideal Liq Vol Flow	(m3/h)	1755	1755			
Molar Enthalpy	(kJ/kgmole)	-3.237e+004	-3.237e+004			
Molar Entropy	(kJ/kgmole-C)	77.50	77.50			
Heat Flow	(kJ/h)	-2.880e+009	-2.880e+009			
Liq Vol Flow @Std Cond	(m3/h)	1648 *	1648			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Pumped Rich Amine (contin

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

Material Stream: Hot Rich Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	50.00 *	50.00			
Pressure:	(kPa)	460.0	460.0			
Molar Flow	(kgmole/h)	8.896e+004	8.896e+004			
Mass Flow	(kg/h)	1.743e+006	1.743e+006			
Std Ideal Liq Vol Flow	(m3/h)	1755	1755			
Molar Enthalpy	(kJ/kgmole)	-3.107e+004	-3.107e+004			
Molar Entropy	(kJ/kgmole-C)	79.23	79.23			
Heat Flow	(kJ/h)	-2.764e+009	-2.764e+009			
Liq Vol Flow @Std Cond	(m3/h)	1648 *	1648			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

LEGENDS Burlington, MA USA	Case Name: CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc Unit Set: SI Date/Time: Thu Apr 04 21:51:42 2019

Material Stream: CO2

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase			
Vapour / Phase Fraction		1.0000	1.0000			
Temperature:	(C)	100.8	100.8			
Pressure:	(kPa)	410.0	410.0			
Molar Flow	(kgmole/h)	1500	1500			
Mass Flow	(kg/h)	5.585e+004	5.585e+004			
Std Ideal Liq Vol Flow	(m3/h)	66.19	66.19			
Molar Enthalpy	(kJ/kgmole)	1.237e+004	1.237e+004			
Molar Entropy	(kJ/kgmole-C)	213.0	213.0			
Heat Flow	(kJ/h)	1.856e+007	1.856e+007			
Liq Vol Flow @Std Cond	(m3/h)	55.92 *	55.92			

COMPOSITION

Overall Phase

Vapour Fraction 1.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0004	20.0977	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	390.2732	0.2601	7030.8117	0.1259	7.0450	0.1064
CO2	1107.9032	0.7385	48758.4893	0.8731	59.0772	0.8926
Nitrogen	1.3811	0.0009	38.6884	0.0007	0.0480	0.0007
Total	1500.1856	1.0000	55848.0871	1.0000	66.1879	1.0000

Vapour Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0004	20.0977	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	390.2732	0.2601	7030.8117	0.1259	7.0450	0.1064
CO2	1107.9032	0.7385	48758.4893	0.8731	59.0772	0.8926
Nitrogen	1.3811	0.0009	38.6884	0.0007	0.0480	0.0007
Total	1500.1856	1.0000	55848.0871	1.0000	66.1879	1.0000

Material Stream: Cool Lean Amine

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	130.1	130.1			
Pressure:	(kPa)	380.0	380.0			
Molar Flow	(kgmole/h)	8.746e+004	8.746e+004			
Mass Flow	(kg/h)	1.687e+006	1.687e+006			
Std Ideal Liq Vol Flow	(m3/h)	1689	1689			
Molar Enthalpy	(kJ/kgmole)	-2.392e+004	-2.392e+004			
Molar Entropy	(kJ/kgmole-C)	88.04	88.04			
Heat Flow	(kJ/h)	-2.092e+009	-2.092e+009			
Liq Vol Flow @Std Cond	(m3/h)	1673 *	1673			

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Cool Lean Amine (continued

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0285	152096.7948	0.0902	149.5588	0.0886
H2O	84816.6180	0.9698	1.527979896e+06	0.9058	1531.0634	0.9066
CO2	153.3294	0.0018	6747.9826	0.0040	8.1761	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.9128	1.0000	1.686824673e+06	1.0000	1688.7983	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0285	152096.7948	0.0902	149.5588	0.0886
H2O	84816.6180	0.9698	1.527979896e+06	0.9058	1531.0634	0.9066
CO2	153.3294	0.0018	6747.9826	0.0040	8.1761	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.9128	1.0000	1.686824673e+06	1.0000	1688.7983	1.0000

Material Stream: Prepared Lean Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	25.00 *	25.00			
Pressure:	(kPa)	260.0 *	260.0			
Molar Flow	(kgmole/h)	8.840e+004 *	8.840e+004			
Mass Flow	(kg/h)	1.705e+006	1.705e+006			
Std Ideal Liq Vol Flow	(m3/h)	1707	1707			
Molar Enthalpy	(kJ/kgmole)	-3.264e+004	-3.264e+004			
Molar Entropy	(kJ/kgmole-C)	77.07	77.07			
Heat Flow	(kJ/h)	-2.885e+009	-2.885e+009			
Liq Vol Flow @Std Cond	(m3/h)	1688 *	1688			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
MEAmine	2490.1988 *	0.0282 *	152111.0568 *	0.0892 *	149.5728 *	0.0876 *
H2O	85721.6522 *	0.9697 *	1.544284179e+06 *	0.9058 *	1547.4006 *	0.9064 *
CO2	190.9088 *	0.0022 *	8401.8413 *	0.0049 *	10.1799 *	0.0060 *
Nitrogen	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
Total	88402.7599	1.0000	1.704797077e+06	1.0000	1707.1533	1.0000

LEGENDS Burlington, MA USA	Case Name: CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc Unit Set: SI Date/Time: Thu Apr 04 21:51:42 2019

Material Stream: Prepared Lean Amine (conti

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2490.1988	0.0282	152111.0568	0.0892	149.5728	0.0876
H2O	85721.6522	0.9697	1.544284179e+06	0.9058	1547.4006	0.9064
CO2	190.9088	0.0022	8401.8413	0.0049	10.1799	0.0060
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	88402.7599	1.0000	1.704797077e+06	1.0000	1707.1533	1.0000

Material Stream: Lean Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase	Aqueous Phase		
Vapour / Phase Fraction		0.0000	0.0000	1.0000		
Temperature:	(C)	145.0	145.0	145.0		
Pressure:	(kPa)	420.0	420.0	420.0		
Molar Flow	(kgmole/h)	8.746e+004	0.3926	8.746e+004		
Mass Flow	(kg/h)	1.687e+006	7.572	1.687e+006		
Std Ideal Liq Vol Flow	(m3/h)	1689	7.581e-003	1689		
Molar Enthalpy	(kJ/kgmole)	-2.260e+004	1.630e+004	-2.260e+004		
Molar Entropy	(kJ/kgmole-C)	89.56	213.1	89.56		
Heat Flow	(kJ/h)	-1.976e+009	6400	-1.976e+009		
Liq Vol Flow @Std Cond	(m3/h)	1673 *	7.511e-003	1673		

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0285	152096.7948	0.0902	149.5588	0.0886
H2O	84816.6180	0.9698	1.527979896e+06	0.9058	1531.0634	0.9066
CO2	153.3294	0.0018	6747.9826	0.0040	8.1761	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.9128	1.0000	1.686824673e+06	1.0000	1688.7983	1.0000

Vapour Phase

Phase Fraction 4.489e-006

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	0.0112	0.0285	0.6827	0.0902	0.0007	0.0886
H2O	0.3807	0.9698	6.8589	0.9058	0.0069	0.9066
CO2	0.0007	0.0018	0.0303	0.0040	0.0000	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.3926	1.0000	7.5720	1.0000	0.0076	1.0000

LEGENDS Burlington, MA USA	Case Name: CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc Unit Set: SI Date/Time: Thu Apr 04 21:51:42 2019

Material Stream: Lean Amine (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9542	0.0285	152096.1121	0.0902	149.5581	0.0886
H2O	84816.2373	0.9698	1.527973037e+06	0.9058	1531.0565	0.9066
CO2	153.3287	0.0018	6747.9523	0.0040	8.1760	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.5202	1.0000	1.686817101e+06	1.0000	1688.7907	1.0000

Material Stream: Cold Lean Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	25.00 *	25.00			
Pressure:	(kPa)	340.0	340.0			
Molar Flow	(kgmole/h)	8.746e+004	8.746e+004			
Mass Flow	(kg/h)	1.687e+006	1.687e+006			
Std Ideal Liq Vol Flow	(m3/h)	1689	1689			
Molar Enthalpy	(kJ/kgmole)	-3.260e+004	-3.260e+004			
Molar Entropy	(kJ/kgmole-C)	77.12	77.12			
Heat Flow	(kJ/h)	-2.851e+009	-2.851e+009			
Liq Vol Flow @Std Cond	(m3/h)	1673 *	1673			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0285	152096.7948	0.0902	149.5588	0.0886
H2O	84816.6180	0.9698	1.527979896e+06	0.9058	1531.0634	0.9066
CO2	153.3294	0.0018	6747.9826	0.0040	8.1761	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.9128	1.0000	1.686824673e+06	1.0000	1688.7983	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0285	152096.7948	0.0902	149.5588	0.0886
H2O	84816.6180	0.9698	1.527979896e+06	0.9058	1531.0634	0.9066
CO2	153.3294	0.0018	6747.9826	0.0040	8.1761	0.0048
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	87459.9128	1.0000	1.686824673e+06	1.0000	1688.7983	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Mixed Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	25.00	25.00			
Pressure:	(kPa)	340.0	340.0			
Molar Flow	(kgmole/h)	8.929e+004	8.929e+004			
Mass Flow	(kg/h)	1.720e+006	1.720e+006			
Std Ideal Liq Vol Flow	(m3/h)	1722	1722			
Molar Enthalpy	(kJ/kgmole)	-3.263e+004	-3.263e+004			
Molar Entropy	(kJ/kgmole-C)	77.06	77.06			
Heat Flow	(kJ/h)	-2.914e+009	-2.914e+009			
Liq Vol Flow @Std Cond	(m3/h)	1706 *	1706			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0279	152096.7948	0.0884	149.5588	0.0869
H2O	86641.9756	0.9704	1.560863896e+06	0.9076	1564.0138	0.9084
CO2	153.3294	0.0017	6747.9826	0.0039	8.1761	0.0047
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	89285.2704	1.0000	1.719708673e+06	1.0000	1721.7486	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0279	152096.7948	0.0884	149.5588	0.0869
H2O	86641.9756	0.9704	1.560863896e+06	0.9076	1564.0138	0.9084
CO2	153.3294	0.0017	6747.9826	0.0039	8.1761	0.0047
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	89285.2704	1.0000	1.719708673e+06	1.0000	1721.7486	1.0000

Material Stream: Make up Water

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	25.00 *	25.00			
Pressure:	(kPa)	370.0 *	370.0			
Molar Flow	(kgmole/h)	1825	1825			
Mass Flow	(kg/h)	3.288e+004 *	3.288e+004			
Std Ideal Liq Vol Flow	(m3/h)	32.95	32.95			
Molar Enthalpy	(kJ/kgmole)	-3.411e+004	-3.411e+004			
Molar Entropy	(kJ/kgmole-C)	74.32	74.32			
Heat Flow	(kJ/h)	-6.226e+007	-6.226e+007			
Liq Vol Flow @Std Cond	(m3/h)	32.93 *	32.93			

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Make up Water (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Overall Phase Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
MEAmine	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
H2O	1825.3576 *	1.0000 *	32884.0000 *	1.0000 *	32.9504 *	1.0000 *
CO2	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
Nitrogen	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
Total	1825.3576	1.0000	32884.0000	1.0000	32.9504	1.0000

Aqueous Phase Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	1825.3576	1.0000	32884.0000	1.0000	32.9504	1.0000
CO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1825.3576	1.0000	32884.0000	1.0000	32.9504	1.0000

Material Stream: Dry CO2

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase	Aqueous Phase		
Vapour / Phase Fraction		1.0000	1.0000	0.0000		
Temperature:	(C)	20.00	20.00	20.00		
Pressure:	(kPa)	370.0	370.0	370.0		
Molar Flow	(kgmole/h)	1116	1116	0.0000		
Mass Flow	(kg/h)	4.891e+004	4.891e+004	0.0000		
Std Ideal Liq Vol Flow	(m3/h)	59.23	59.23	0.0000		
Molar Enthalpy	(kJ/kgmole)	9178	9178	-3.437e+004		
Molar Entropy	(kJ/kgmole-C)	199.9	199.9	73.72		
Heat Flow	(kJ/h)	1.025e+007	1.025e+007	0.0000		
Liq Vol Flow @Std Cond	(m3/h)	48.97 *	48.97	0.0000		

COMPOSITION

Overall Phase Vapour Fraction 1.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6280	0.0006	20.0970	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	7.3422	0.0066	132.2711	0.0027	0.1325	0.0022
CO2	1106.9751	0.9916	48717.6438	0.9961	59.0277	0.9967
Nitrogen	1.3811	0.0012	38.6878	0.0008	0.0480	0.0008
Total	1116.3265	1.0000	48908.6998	1.0000	59.2259	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Dry CO2 (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Vapour Phase Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6280	0.0006	20.0970	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	7.3422	0.0066	132.2711	0.0027	0.1325	0.0022
CO2	1106.9751	0.9916	48717.6438	0.9961	59.0277	0.9967
Nitrogen	1.3811	0.0012	38.6878	0.0008	0.0480	0.0008
Total	1116.3265	1.0000	48908.6998	1.0000	59.2259	1.0000

Aqueous Phase Phase Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0000	0.9976	0.0000	0.9941	0.0000	0.9929
CO2	0.0000	0.0024	0.0000	0.0059	0.0000	0.0071
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0000	1.0000	0.0000	1.0000	0.0000	1.0000

Material Stream: Water

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase	Aqueous Phase		
Vapour / Phase Fraction		0.0000	0.0000	1.0000		
Temperature:	(C)	20.00	20.00	20.00		
Pressure:	(kPa)	370.0	370.0	370.0		
Molar Flow	(kgmole/h)	383.9	0.0000	383.9		
Mass Flow	(kg/h)	6939	0.0000	6939		
Std Ideal Liq Vol Flow	(m3/h)	6.962	0.0000	6.962		
Molar Enthalpy	(kJ/kgmole)	-3.437e+004	9178	-3.437e+004		
Molar Entropy	(kJ/kgmole-C)	73.72	199.9	73.72		
Heat Flow	(kJ/h)	-1.319e+007	0.0000	-1.319e+007		
Liq Vol Flow @Std Cond	(m3/h)	6.949 *	0.0000	6.949		

COMPOSITION

Overall Phase Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	382.9310	0.9976	6898.5406	0.9941	6.9125	0.9929
CO2	0.9281	0.0024	40.8454	0.0059	0.0495	0.0071
Nitrogen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
Total	383.8592	1.0000	6939.3873	1.0000	6.9620	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Water (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Vapour Phase

Phase Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0006	0.0000	0.0004	0.0000	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0000	0.0066	0.0000	0.0027	0.0000	0.0022
CO2	0.0000	0.9916	0.0000	0.9961	0.0000	0.9967
Nitrogen	0.0000	0.0012	0.0000	0.0008	0.0000	0.0008
Total	0.0000	1.0000	0.0000	1.0000	0.0000	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	382.9310	0.9976	6898.5406	0.9941	6.9125	0.9929
CO2	0.9281	0.0024	40.8454	0.0059	0.0495	0.0071
Nitrogen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
Total	383.8592	1.0000	6939.3873	1.0000	6.9620	1.0000

Material Stream: Cool CO2

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase	Aqueous Phase		
Vapour / Phase Fraction		0.7441	0.7441	0.2559		
Temperature:	(C)	20.00 *	20.00	20.00		
Pressure:	(kPa)	370.0	370.0	370.0		
Molar Flow	(kgmole/h)	1500	1116	383.9		
Mass Flow	(kg/h)	5.585e+004	4.891e+004	6939		
Std Ideal Liq Vol Flow	(m3/h)	66.19	59.23	6.962		
Molar Enthalpy	(kJ/kgmole)	-1965	9178	-3.437e+004		
Molar Entropy	(kJ/kgmole-C)	167.6	199.9	73.72		
Heat Flow	(kJ/h)	-2.948e+006	1.025e+007	-1.319e+007		
Liq Vol Flow @Std Cond	(m3/h)	55.92 *	48.97	6.949		

COMPOSITION

Overall Phase

Vapour Fraction 0.7441

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0004	20.0977	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	390.2732	0.2601	7030.8117	0.1259	7.0450	0.1064
CO2	1107.9032	0.7385	48758.4893	0.8731	59.0772	0.8926
Nitrogen	1.3811	0.0009	38.6884	0.0007	0.0480	0.0007
Total	1500.1856	1.0000	55848.0871	1.0000	66.1879	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Cool CO2 (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Vapour Phase

Phase Fraction 0.7441

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6280	0.0006	20.0970	0.0004	0.0177	0.0003
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	7.3422	0.0066	132.2711	0.0027	0.1325	0.0022
CO2	1106.9751	0.9916	48717.6438	0.9961	59.0277	0.9967
Nitrogen	1.3811	0.0012	38.6878	0.0008	0.0480	0.0008
Total	1116.3265	1.0000	48908.6998	1.0000	59.2259	1.0000

Aqueous Phase

Phase Fraction 0.2559

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	382.9310	0.9976	6898.5406	0.9941	6.9125	0.9929
CO2	0.9281	0.0024	40.8454	0.0059	0.0495	0.0071
Nitrogen	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
Total	383.8592	1.0000	6939.3873	1.0000	6.9620	1.0000

Material Stream: Collected Flue Gas

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase			
Vapour / Phase Fraction		1.0000	1.0000			
Temperature:	(C)	25.00 *	25.00			
Pressure:	(kPa)	200.0 *	200.0			
Molar Flow	(kgmole/h)	3.000e+004 *	3.000e+004			
Mass Flow	(kg/h)	8.808e+005	8.808e+005			
Std Ideal Liq Vol Flow	(m3/h)	1027	1027			
Molar Enthalpy	(kJ/kgmole)	8691	8691			
Molar Entropy	(kJ/kgmole-C)	186.5	186.5			
Heat Flow	(kJ/h)	2.607e+008	2.607e+008			
Liq Vol Flow @Std Cond	(m3/h)	---	---			

COMPOSITION

Overall Phase

Vapour Fraction 1.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	5501.8470 *	0.1834 *	176059.1044 *	0.1999 *	154.7527 *	0.1506 *
MEAmine	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
H2O	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *	0.0000 *
CO2	1154.2125 *	0.0385 *	50796.5466 *	0.0577 *	61.5466 *	0.0599 *
Nitrogen	23343.9405 *	0.7781 *	653933.8164 *	0.7424 *	810.9560 *	0.7894 *
Total	30000.0000	1.0000	880789.4674	1.0000	1027.2553	1.0000

LEGENDS Burlington, MA USA	Case Name: CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc Unit Set: SI Date/Time: Thu Apr 04 21:51:42 2019

Material Stream: Collected Flue Gas (continue

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

COMPOSITION

Vapour Phase Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	5501.8470	0.1834	176059.1044	0.1999	154.7527	0.1506
MEAmine	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	1154.2125	0.0385	50796.5466	0.0577	61.5466	0.0599
Nitrogen	23343.9405	0.7781	653933.8164	0.7424	810.9560	0.7894
Total	30000.0000	1.0000	880789.4674	1.0000	1027.2553	1.0000

Material Stream: Hotter Rich Amine

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Vapour Phase	Aqueous Phase		
Vapour / Phase Fraction		0.0001	0.0001	0.9999		
Temperature:	(C)	110.0 *	110.0	110.0		
Pressure:	(kPa)	420.0	420.0	420.0		
Molar Flow	(kgmole/h)	8.896e+004	8.647	8.895e+004		
Mass Flow	(kg/h)	1.743e+006	283.6	1.742e+006		
Std Ideal Liq Vol Flow	(m3/h)	1755	0.3291	1755		
Molar Enthalpy	(kJ/kgmole)	-2.612e+004	1.254e+004	-2.613e+004		
Molar Entropy	(kJ/kgmole-C)	85.41	213.6	85.40		
Heat Flow	(kJ/h)	-2.324e+009	1.084e+005	-2.324e+009		
Liq Vol Flow @Std Cond	(m3/h)	1648 *	0.3172	1648		

COMPOSITION

Overall Phase Vapour Fraction 0.0001

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.6281	0.0000	20.0977	0.0000	0.0177	0.0000
MEAmine	2489.9653	0.0280	152096.7948	0.0873	149.5588	0.0852
H2O	85206.8913	0.9578	1.535010708e+06	0.8808	1538.1084	0.8764
CO2	1261.2327	0.0142	55506.4719	0.0319	67.2533	0.0383
Nitrogen	1.3811	0.0000	38.6884	0.0000	0.0480	0.0000
Total	88960.0984	1.0000	1.742672761e+06	1.0000	1754.9861	1.0000

Vapour Phase Phase Fraction 9.720e-005

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.3914	0.0453	12.5261	0.0442	0.0110	0.0335
MEAmine	0.0065	0.0008	0.3989	0.0014	0.0004	0.0012
H2O	2.9357	0.3395	52.8876	0.1865	0.0530	0.1610
CO2	4.3121	0.4987	189.7736	0.6691	0.2299	0.6987
Nitrogen	1.0010	0.1158	28.0411	0.0989	0.0348	0.1057
Total	8.6468	1.0000	283.6274	1.0000	0.3291	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Material Stream: Hotter Rich Amine (continue

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

COMPOSITION

Aqueous Phase

Phase Fraction 0.9999

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.2366	0.0000	7.5716	0.0000	0.0067	0.0000
MEAmine	2489.9588	0.0280	152096.3959	0.0873	149.5584	0.0852
H2O	85203.9555	0.9579	1.534957820e+06	0.8810	1538.0554	0.8766
CO2	1256.9206	0.0141	55316.6982	0.0317	67.0233	0.0382
Nitrogen	0.3801	0.0000	10.6473	0.0000	0.0132	0.0000
Total	88951.4516	1.0000	1.742389133e+06	1.0000	1754.6570	1.0000

Material Stream: Depressed Amine

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

		Overall	Aqueous Phase			
Vapour / Phase Fraction		0.0000	1.0000			
Temperature:	(C)	25.00	25.00			
Pressure:	(kPa)	260.0 *	260.0			
Molar Flow	(kgmole/h)	8.929e+004	8.929e+004			
Mass Flow	(kg/h)	1.720e+006	1.720e+006			
Std Ideal Liq Vol Flow	(m3/h)	1722	1722			
Molar Enthalpy	(kJ/kgmole)	-3.263e+004	-3.263e+004			
Molar Entropy	(kJ/kgmole-C)	77.06	77.06			
Heat Flow	(kJ/h)	-2.914e+009	-2.914e+009			
Liq Vol Flow @Std Cond	(m3/h)	1706 *	1706			

COMPOSITION

Overall Phase

Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0279	152096.7948	0.0884	149.5588	0.0869
H2O	86641.9756	0.9704	1.560863896e+06	0.9076	1564.0138	0.9084
CO2	153.3294	0.0017	6747.9826	0.0039	8.1761	0.0047
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	89285.2704	1.0000	1.719708673e+06	1.0000	1721.7486	1.0000

Aqueous Phase

Phase Fraction 1.000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Oxygen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MEAmine	2489.9653	0.0279	152096.7948	0.0884	149.5588	0.0869
H2O	86641.9756	0.9704	1.560863896e+06	0.9076	1564.0138	0.9084
CO2	153.3294	0.0017	6747.9826	0.0039	8.1761	0.0047
Nitrogen	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	89285.2704	1.0000	1.719708673e+06	1.0000	1721.7486	1.0000

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Energy Stream: Pump Energy

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	P-100		
Duty SP:	6.618e+005 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO		PRODUCT FROM		LOGICAL CONNECTION	
Pump:	P-100				

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

Energy Stream: Condensor Energy

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	Condenser @COL2		
Duty SP:	6.384e+007 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO		PRODUCT FROM		LOGICAL CONNECTION	
		Distillation:	T-101		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

Energy Stream: Reboiler Energy

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	Reboiler @COL2		
Duty SP:	4.302e+008 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO		PRODUCT FROM		LOGICAL CONNECTION	
Distillation:	T-101				

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

LP Steam Generation

Energy Stream: Cooler Energy

Fluid Package: Basis-1
Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	E-101		

LEGENDS Burlington, MA USA	Case Name:	CO2 Capture_Save_Flue Gas Model_iteration8_optimized_final.hsc
	Unit Set:	SI
	Date/Time:	Thu Apr 04 21:51:42 2019

Energy Stream: Cooler Energy (continued)

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

Duty SP:	7.592e+008 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO	PRODUCT FROM	LOGICAL CONNECTION
	Cooler: E-101	

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

Energy Stream: CO2 Cooler

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	E-102		
Duty SP:	2.151e+007 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO	PRODUCT FROM	LOGICAL CONNECTION
	Cooler: E-102	

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

Energy Stream: Heater Energy

Fluid Package: Basis-1

Property Package: Amine Pkg - KE

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	E-103		
Duty SP:	4.398e+008 kJ/h	Minimum Available Duty:	---	Maximum Available Duty:	---

UNIT OPERATIONS

FEED TO	PRODUCT FROM	LOGICAL CONNECTION
Heater: E-103		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY