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Methods for providing heat to electric operated LNG plant

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Master of Science in Product Design and Manufacturing
Submission date: June 2010
Supervisor: Geir Asle Owren, EPT

Norwegian University of Science and Technology
Department of Energy and Process Engineering

Problem Description

1. Give an overview of possible methods for heat generation at the LNG plant at Melkøya when co-generation is not applicable
2. Define scenarios for the most promising methods for heat generation at the LNG plant at Melkøya
3. In agreement with supervisor, select at least one scenario for detailed simulation
a) Define the process and establish a simulation model for the selected scenario(s)
b) Simulate the scenario i) Calculate utility need. ii) Calculate emissions to air
c) Assess integration with the existing plant at Melkøya
4. Recommend a method for heat generation for the LNG plant at Melkøya

Assignment given: 25. January 2010
Supervisor: Geir Asle Owren, EPT

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MASTER THESIS

for

Stud.techn. Cecilie Magrethe Tangås
Spring 2010

Methods for providing heat to electric operated LNG plant.

Metoder for å generere varme til elektrisk drevet LNG anlegg.

Background and objective

Snøhvit Train I, sited outside Hammerfest in Northern Norway, is the first LNG facility in the world where the cooling compressors are driven by electric motors. Heat and power requirements are met by the internal combined heat and power (CHP) plant.

The CO2 emission from the CHP is slightly above 1 mill ton per year. It is rated as one of the largest point emissions in Norway. Consequently, Melkøya is high up on the list when measures under the climate settlement in the Norwegian Parliament (Stortinget) are considered. The Norwegian Pollution Control Authorities (SFT) has instructed the Operator of Snøhvit to study measures that can reduce the CO2 emission from the LNG plant.

The candidate has developed a roadmap to reduced emissions of CO2 from the LNG plant in her Project Work. The roadmap clearly identifies the import of renewable electricity as the most promising way to reduced CO2 emissions from the LNG plant. The challenge is to generate the necessary amount of heat with lowest possible CO2 emissions when cogeneration is not applicable.

The objective of the master thesis is to evaluate methods for heat generation to the LNG plant and to conclude with an optimal method with regard to CO2 emission and operability. The methods shall include but not be limited to gas fired options with and without CO2 capture, use of bio fuel and heat pumps.

The work includes the possibility for a dialogue with industrial companies and organizations, and it is up to the candidate to make use of this possibility.

The following questions should be considered in the project work:

1. Give an overview of possible methods for heat generation at the LNG plant at Melkøya when cogeneration is not applicable
2. Define scenarios for the most promising methods for heat generation to the LNG plant at Melkøya
3. In agreement with supervisor, select at least one scenario for a detailed simulation
    a. Define the process and establish a simulation model for the selected scenario(s)
    b. Simulate the scenario:
        i. Calculate utility need
        ii. Calculate emissions to air

c. Assess integration with the existing plant at Melkøya

4. Recommend a method for heat generation for the LNG plant at Melkøya

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Within 14 days of receiving the written text on the diploma thesis, the candidate shall submit a research plan for his project to the department.

When the thesis is evaluated, emphasis is put on processing of the results, and that they are presented in tabular and/or graphic form in a clear manner, and that they are analyzed carefully.

The thesis should be formulated as a research report with summary both in English and Norwegian, conclusion, literature references, table of contents etc. During the preparation of the text, the candidate should make an effort to produce a well-structured and easily readable report. In order to ease the evaluation of the thesis, it is important that the cross-references are correct. In the making of the report, strong emphasis should be placed on both a thorough discussion of the results and an orderly presentation.

The candidate is requested to initiate and keep close contact with his/her academic supervisor(s) throughout the working period. The candidate must follow the rules and regulations of NTNU as well as passive directions given by the Department of Energy and Process Engineering.

Pursuant to "Regulations concerning the supplementary provisions to the technology study program/Master of Science" at NTNU §20, the Department reserves the permission to utilize all the results and data for teaching and research purposes as well as in future publications.

One – 1 complete original of the thesis shall be submitted to the authority that handed out the set subject. (A short summary including the author's name and the title of the thesis should also be submitted, for use as reference in journals (max. 1 page with double spacing)).
Two – 2 – copies of the thesis shall be submitted to the Department. Upon request, additional copies shall be submitted directly to research advisors/companies. A CD-ROM (Word format or corresponding) containing the thesis, and including the short summary, must also be submitted to the Department of Energy and Process Engineering

Department of Energy and Process Engineering, 17. January 2010

Olav Bolland
Department Head

Geir Owren
Academic Supervisor

Research Advisors:
Kirsti Tangvik, Senior Advisor, Statoil

Preface

This report is written as the finishing work during the tenth and final semester of the Masters program in Product design and Manufacturing at the Norwegian University of Science and Technology. The work is carried out at the Department of Energy and Process engineering during spring 2010.

The objective if the thesis is to evaluate methods for heat generation to Hammerfest LNG plant, and conclude with the optimal method with respect to CO_2 emission and operability.

I would like to thank my supervisors Geir A. Owren and Kirsti Tangvik for guidance during this semester.

Trondheim, June 2010

Cecilie M. Tangås

Cecilie M. Tangås

Abstract

Hammerfest LNG plant, located at Melkøya outside Hammerfest, is supplied with heat and power from an on-site combined heat and power (CHP-) plant. This natural gas fired CHP emits more than one million tons of CO_2 per year, which makes it one of Norway's largest point emissions. Melkøya is therefore of large interest when it comes to reducing the national CO_2 emissions.

Previous work has identified import of renewable electricity from the national grid to power the LNG plant as the most promising solution to reduction in the CO_2 emissions from Melkøya.

This report assesses different heat generation alternatives when co-generation is no longer applicable, in order to find the optimal solution for Melkøya, with respect to CO_2 emission and operability. The most promising alternatives were subject to simulation, where CO_2 emission, fuel/ power demand etc. were identified.

Heat pumps are found to be the thermodynamically most favourable alternative. It is not able to cover the entire heat demand at Melkøya, but used in combination with other methods of heat generation, the result is significantly reduced fuel and power consumption, as well as CO_2 emissions.

Further investigation of use of heat pumps as heat providers at Melkøya is therefore recommended.

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1 Introduction

Hammerfest LNG plant, located at Melkøya outside Hammerfest, is the northernmost LNG plant in the world. It is also the first LNG plant in the world where the cooling compressors are driven by electric motors.

The power and heat is generated by five gas turbines on site in a combined heat and power (CHP) plant. The CO_2 emission from this CHP is more than one million tonnes per year, making it one of the largest point emissions in Norway. Melkøya is therefore an important element on the Norwegian Governments agenda, when it comes to reducing the national CO_2 emissions, and The Norwegian Pollution Control Authorities (KLIF, former SFT) has therefore instructed Statoil to assess measures to reduce the CO_2 emissions from the LNG plant.

Prior to this master thesis, a roadmap to reduced CO_2 emissions from Melkøya has been developed. This roadmap identifies use of renewable electricity to power the LNG plant as the most promising way to reduce the CO_2 emissions. The electric power is to be imported from the national grid. Powering the LNG plant with electricity from the grid will require alternative ways to generate the necessary heat, as co-generation is no longer applicable. The challenge is to generate the heat with lowest possible CO_2 emissions.

In collaboration with the supervisors, a selection of heat generation alternatives has been selected for assessment. Based on the evaluation of these alternatives, the most promising solutions will be defined, before at least one of the methods is chosen for simulation. Potential integration with the existing plant will also assessed. Finally, a heat generation method for Melkøya will be recommended.

A number of simplifications and assumptions are necessary to evaluate the heat generation methods, as the public information about the process at Melkøya is limited. The simplifications and assumptions are described when appropriate.

2 Hammerfest LNG

Hammerfest LNG is Europe's first, and the world's northernmost export facility for liquefied natural gas (LNG). The plant is supplied with natural gas from the fields Snøhvit and Albatross in the Barents Sea. Askeladd will later also be put on stream.

The LNG plant is designed to be the most environmentally friendly LNG-facility in the world. The existing energy solution, along with high energy-efficiency, contributes to relatively low CO_2 emissions. In addition, the CO_2 separated from the natural gas is compressed and re-injected to a reservoir below the Snøhvit-field. This reduces the CO_2 emissions even further.

Hammerfest LNG is the first LNG-facility where the cooling compressors are driven by electric motors. This enables import of electricity from the national grid to power the compressors.

The LNG plant currently consists of a single processing line (Train I), but Statoil is considering expanding the production capacity with a Train II. It is assumed that Train II will have the same heat and power demand as the existing Train I.

This report will mainly assess the existing Train I, but some considerations regarding a future Train II will also be made.

2.1 Heat and power demand

LNG production is energy consuming. The total power demand of the existing Train I is 215 MW [**1**], or approximately 1.7 TWh per year. The main consumers are the VSD motors on the cooling compressors.

The average heat demand is 167.2 MW (≈1.32 TWh per year) [**1**]. The heat demand is however temperature dependent; at lower ambient temperatures the heat demand increases. This gives a maximum heat demand of 197 MW, while it at design temperature (4°C) is 147 MW [**1**]. The main consumers are listed in Table 2-1.

Note these are the estimated numbers for the heat and power demand. The current power consumption is somewhat larger. The liquefaction process has however not performed as anticipated, and the power consumption is therefore somewhat higher than design.

Table 2-1. Main heat consumers [1]

Process	Hot oil 260°C	Hot oil 192°C	Hot oil 150°C
Condensate fractionation	23		
Dehydration	10		
Condensate stabilization	8,7		
Prevent iceing	5,3		
CO2 separation		76,5	
MEG regeneration		11,2	
LNG/LPG fractionation		7,1	
Hydrate controll			10,3
Heating of buildings, road de-icing			6,6
Condensate stabilization			5,2
fuel gas			2,4
MEG heating			0,9
Total	**167,2**		

The CO_2-removal process dominates the heat demand, with a heat demand of almost 50% of the total heat demand.

The existing Train I is mainly self-supplied with both heat and power, generated on site in the combined heat and power plant (CHP). The CHP consists of five GE LM6000PD gas turbines with hot oil heat recovery units. The gas turbines are driven by natural gas from the fields.

The heat surplus in the exhaust gas from the gas turbines is large enough to cover the total heat demand, and is distributed to the LNG plant through the hot oil system.

The electric efficiency of the gas turbines is 39.8%, but the total energy efficiency of the CHP is 70,7% [**1**].

2.2 CO_2 emissions

Statoil was in 2003 permitted to discharge 920 000 tons of CO_2 per year from the energy-plant at Melkøya [**2**].

Flaring during start-up and during breaking-in the production facility has caused larger CO_2 emissions the first years of production. In 2007 and 2008, the total CO_2 emission (flaring and power/heat production) was 1 622 960 tons and 1 356 230 tons respectively [**3**]. Hammerfest LNG is therefore ranked as the second largest point emission in Norway, responsible for approximately 3% of Norway's total CO_2 emissions (44.2 million tons in 2008 [**4**]).

The emission permission might not be expanded for the future Train II.

The CO_2 content in the natural gas entering Melkøya has to be reduced to avoid freeze out in the liquefaction process. 700 000 tons of CO_2 per year are captured by amine absorption, and is compressed and re-injected for storage in a reservoir below Snøhvit.

3 Potential heat generation methods

When using electricity from the grid to power the LNG plant, it is necessary to find alternative ways to cover the heat demand. It is desirable that the heat is generated with as low as possible CO_2 emissions, in order to ensure a high enough total CO_2 reduction for justifying the electrification investments. It is also desirable to find thermodynamically sound solution with low fuel/power consumption, good operability, and low cost.

Using furnaces to produce heat is a simple and well-known technology. The furnaces can be fired with fossil fuels such as coal, oil and gas, or CO_2-neutral fuels like biomass or waste. Burning these fuels all result in emissions of CO_2, NO_X and particles. The NO_X emissions are however substantially lower than for combustion engines. Biomass and waste can be regarded as CO_2-neutral if one assumes that it is produced and transported without substantial emissions.

Post-combustion carbon capture is a possibility for reducing the CO_2 emissions from the furnaces, but a drawback is that post-combustion carbon capture itself is very energy demanding. Another option for CO_2 capture is to burn the fuel with pure oxygen instead of air (Oxy-fuel combustion). Oxy-fuel combustion simplifies the CO_2 capture, and reduces the emissions of NO_X, but the oxygen production is very power demanding. Both the alternatives also need power for compression/pumping of the CO_2 for transport and storage.

Electric heating is another heat generation option, either by direct electric heating or by use of heat pumps. Electricity can also be regarded as CO_2-neutral if one assumes that the electricity is generated from clean, renewable energy sources or in power plants with CO_2-capture. Use of electricity for heating would mean a higher demand for electricity from the grid.

In collaboration with the supervisors, the following heat generation methods has been selected for assessment; furnaces fired with natural gas with and without post-combustion carbon capture, Oxy-fuel furnaces with CO_2 capture, furnaces fired with CO_2-neutral fuels (biomass, waste), direct electric heating and heat pumps.

In the following section, each of the selected heat generation methods will be discussed. In order to compare the alternatives more quantitatively, the CO_2 emissions, along with fuel and/or power consumption and related operational costs for each of the methods have been estimated. Investment cost has in some cases been discussed.

The assumptions made for these calculations, and for the calculations in the following sections are discussed in Appendix A.

The heat generation options also need comparison with the existing energy solution. The gas consumption, CO_2 emission and cost of the existing CHP have therefore also been estimated. The results are given in Table 3-1.

The calculated CO_2 emission is somewhat lower than the emission permit of 920 000 tons per year.

Table 3-1. The existing CHP

	Gas consumption (ton/year)	Gas cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Reference Energy plant (CHP Train I)	314 000	266,0	854 000	299,0	n/a	565,0

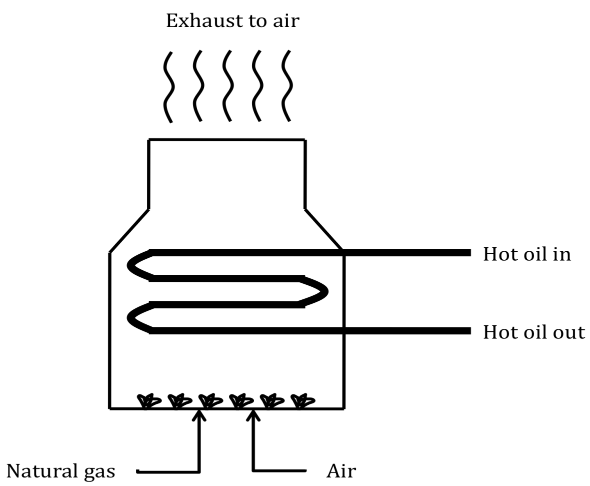
In case of electrification, 215 MW of electric power has to be imported from the grid, at an estimated total cost of 766 million NOK per year. This comes as an additional cost to all of the heat generation options, and is therefore not included in the tables.

3.1 Furnaces fired with natural gas

Burning natural gas with air generates hot exhaust gas that can be used to heat the hot oil. A principal sketch of a gas-fired furnace is shown in Figure 3-1.

Natural gas and air enters the combustion chamber, and are burned in burners. Hot exhaust gas is generated. The hot exhaust cools while rejecting heat to a heat demanding process or a heat carrier, in this case the hot oil. The exhaust is then vented to air.

Figure 3-1. Gas-fired furnace



Although burning natural gas is cleaner than other fossil fuels, it still results in emission of CO_2, NO_X and particles.

Natural gas as fuel has the advantage of already being in a gas state, as it gives a better fuel/air mixing compared to combustion of solid or liquid fuels. More precise mixing contributes to higher efficiency. As natural gas also burns with a more pure flame, problems related to soot on surfaces are reduced.

Due to lower content of corrosive components in the exhaust gas from gas-fired furnaces, the exhaust gas can in modern furnaces be cooled down to below the water dew point temperature. The result is a potential energy efficiency of more than 100% of the lower heating value (LHV) of the fuel gas, as the heat of condensation of the water vapour is utilized. 100% utilization of the LHV is not necessarily achievable in this case, as the temperature of the exhaust gas has to be kept at a temperature higher than the temperature of the returning hot oil from the consumers.

Gas-fired furnaces deliver heat at high temperatures, higher than necessary to heat the hot oil to 260°C. The adiabatic flame temperature of stoichiometric combustion of methane with air is 1953°C [**5**].

Melkøya benefits from having the gas easily available, no new infrastructure is necessary for transportation of the gas. A drawback is that burning some of the gas will result in shorter lifetime of the fields. Boil-off gas from the LNG tanks could also be used as fuel, but this would in addition to less product to sell lead to a higher energy consumption per ton produced LNG.

Since less effect is needed from the furnaces compared to the existing CHP (167 MW < 215 MW), less fuel gas is needed. Combined with the fact that the furnaces have a much higher efficiency (> 90%), it is expected that the CO_2 emissions from the furnaces will be lower than from the existing CHP.

Table 3-2 shows the estimated CO_2 emission from the furnaces, as well as gas consumption and cost.

The results of the calculations suggest that using natural gas-fired furnaces to produce the heat in case of electrification significantly reduces the gas consumption and thereby the CO_2 emissions compared to the existing CHP.

The economical effects are reduced gas and CO_2 cost, but taking into consideration the additional cost of 766 million NOK for the imported electric power, the annual cost of this alternative becomes higher than for the existing energy plant.

Table 3-2. Natural gas-fired furnaces

	Gas consumption (ton/year)	Gas cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Natural gas fired furnace	108 000	91,4	293000	102,7	n/a	194,1

3.2 Furnaces with post-combustion carbon capture

The principle of post-combustion carbon capture is separation of CO_2 from the exhaust gas generated by combustion of fuels. The objective is to create a CO_2 stream for storage in a reservoir, enhanced oil recovery (EOR) or sale. In this case, a post-combustion capture process could be used to remove CO_2 from the exhaust gas from the natural gas fired furnaces discussed in the previous section.

The drawback is that the CO_2 separation processes in general are energy intensive. In addition, energy is needed for handling, transport and storage of the CO_2.

There are a number of existing post-combustion carbon capture technologies, but chemical absorption represents the most commercially ready technology [**6**] and is currently the preferred technology for post-combustion carbon capture [**7**]. Other CO_2 capture technologies are separation with membranes, CO_2 removal by cryogenic distillation, and adsorption.

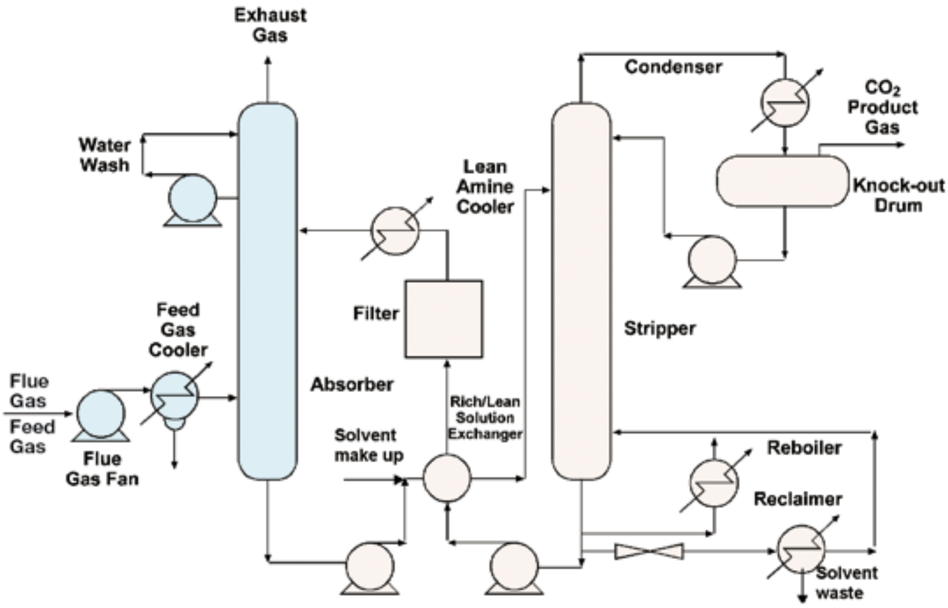
The absorption technology makes use of the reversible nature of the chemical reaction of an aqueous alkaline solvent with an acid gas. The CO_2 is removed in a continuous scrubbing process. This process is illustrated in Figure 3-2.

Cooled, CO_2 rich exhaust gas is fed into the bottom of the absorber, and lean solvent is fed into the top of the absorber. A mass transfer of CO_2 takes place from the exhaust gas to the solvent due to the driving concentration force. The CO_2 rich solvent from the bottom of the absorber is regenerated in a stripping process where heat is added to remove the CO_2 from the solvent solution. The stripper is operated at pressures not much above the atmospheric pressure and at elevated temperatures (100-140°C) [**7**]. The regenerated solvent is then returned to the top of the absorber.

The heat needed for regeneration of the solvents is one of the major drawbacks of chemical absorption/desorption technology.

Typical CO_2 recoveries are between 80% and 95% [**7**].

Figure 3-2.Schematic of chemical absorption system [7]



The chemical absorption technology is already widely used in gas purification, e.g. for acid gas removal from natural gas [**8**]. The technology is in use at Melkøya to remove CO_2 from the natural gas before liquefaction. There is however aspects of removing CO_2 from exhaust gas compared to from natural gas that makes it more challenging. While the pressure of the natural gas when removing CO_2 is high, the exhaust from the power plants or furnaces is at approximately atmospheric pressure.

Solvents used for CO_2 absorption is in general most efficient when the CO_2 partial pressure is high. Low total flue gas pressure and relative low concentrations of CO_2 are therefore challenges for capturing the CO_2 in a cost- and energy efficient way, as a higher flow rate of solvent solution has to be used. Stoichiometric, complete combustion of the assumed natural gas will result in exhaust gas containing approximately 9.6 mole% CO_2. With atmospheric pressure this results in a CO_2 partial pressure of only 9.7 kPa. The natural gas has a CO_2 concentration of approximately 5%, but with a pressure in the range of 60bar, the CO_2 partial pressure is 303 kPa. The CO_2 loading of the solvents is also generally best at low temperatures, cooling of the exhaust gas after the hot oil is heated might therefore be necessary.

A large number of solvents are available. The absorbent should be able to bind large amounts of CO_2 relatively quickly, and have low desorption temperature, and low heat of reaction to reduce the need for regeneration energy. In addition, it should have low degradation and by-product formation rate.

The most common CO_2 absorption chemicals are various alkanolamines. MDEA – methyldiethanolamine is one of the most used amines. MDEA has several advantages over other amines, such as lower heat of reaction (less heat is needed for stripping), high resistance to thermal and chemical degradation, and high loading capacity [**8**]. The disadvantage is low rate of reaction with CO_2. By mixing MDEA with other amines, the reaction kinetics can be improved. The result is aMDEA, activated or accelerated MDEA. One of these activators is Piperazine.

Amine absorption technology is regarded as mature, but some risk is associated with amine CO_2 removal from exhaust gas. The primary risk is the potential negative health and environmental effect caused by amine emissions to air. Another risk is large-scale applications. Because of large exhaust gas volumes, and low pressure, the equipment has to be very large [**9**].

Another range of absorption solvents used to remove acid gases is carbonate salt solutions.

Aqueous carbonate solutions are used for CO_2 absorption, by performing a cyclic change between carbonate and bicarbonate. In contact with gas containing CO_2, the carbonate solution will convert the CO_2 to bicarbonate (HCO_3^-). The bicarbonate rich absorbent is regenerated back to CO_2 and carbonate by adding heat. The carbonate is then cooled and sent back to the absorber for a new cycle in a continuous process [**9**].

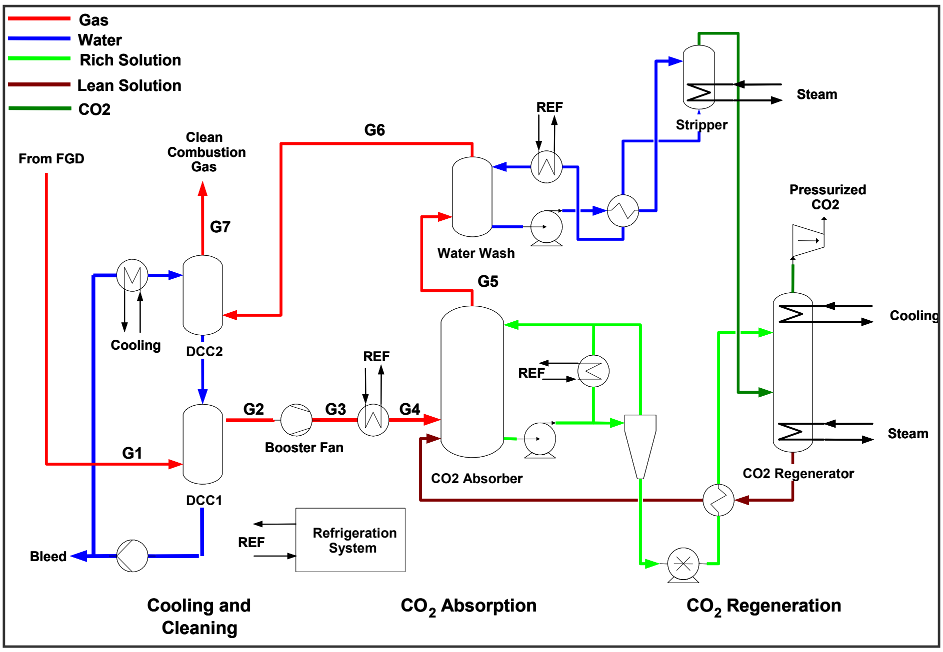
Processes based on Potassium carbonate (K_2CO_3) are widely applied in the industry for CO_2 removal from gas mixtures [**8**]. The most well known is the Benfield process. This process is used with high CO_2 partial pressure, which is generally not the case for combustion exhaust gas.

Pressurized combustion is a technology that might make CO_2 absorption by Potassium carbonate (or amines) more efficient. Sargas has developed technology where the power production and CO_2 capture is integrated. The technology is so far only verified for pressurized combustion of coal. The CO_2 is captured by absorption into Potassium carbonate.

Another carbonate process alternative for CO_2 capture from exhaust gas under development by Alstom is the so-called "Chilled Ammonia Process" (CAP), based on Ammonium carbonate ($(NH_4)_2CO_3$). The name is given because the absorber is operated at low temperature. An illustration of the CAP is found in Figure 3-3.

The Chilled Ammonia Process captures CO_2 from the exhaust gas by direct contact with Ammonium carbonate at temperatures below 20°C in the absorber. Ammonium carbonate reacts with CO_2 to form ammonia bicarbonate, which precipitates and forms a "slurry" of ammonium bicarbonate solids in solution. The CO_2 rich ammonium bicarbonate slurry is pressurized and sent to regeneration where heat is supplied to reverse the reaction, and separate clean CO_2 from the solution. CO_2 lean ammonium carbonate solution is returned to the CO_2 absorber. [**10**]

Figure 3-3. Schematic of the Chilled Ammonia Process [10]



The main advantage of the chilled ammonia technology is that it is expected to require much less energy for regeneration compared to the amine technology. Low degradation and high CO_2 purity are other advantages. In addition, CO_2 leaves the regenerator pressurized, saving compression work. However, energy is required for chilling the ammonia [**10**] [**11**]. Another advantage is that there is less health and environmental risk related to release of ammonia.

The CAP is not yet commercially available. The CAP is together with amine absorption the two technologies that are to be tested at Test Centre Mongstad (TCM).

Since amine technology for CO_2 capture can be regarded as technical mature to a further extent than the CAP, it is used as basis for the evaluation of post-combustion carbon capture from the natural gas fired furnaces at Melkøya.

Removing CO_2 from the exhaust gas from the furnaces by amine absorption at removal rate 80% and 95% will result in a significant increase in heat demand, 25.6 MW and 30.4 MW respectively. It is assumed that electric heaters cover this additional heat demand.

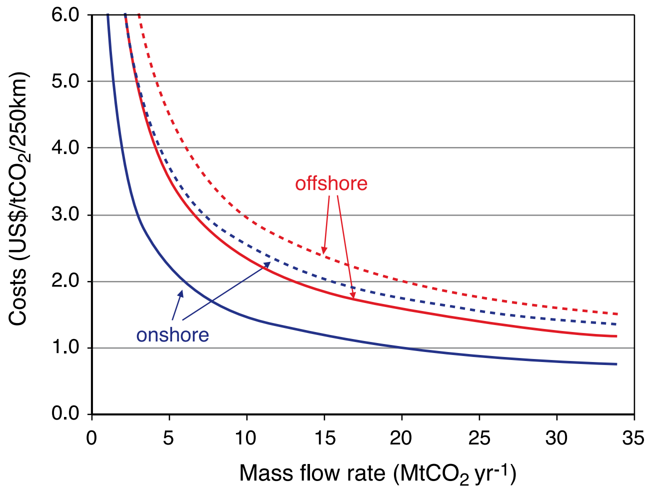
Table 3-3. Furnaces with CO_2 removal by amine absorption

	Gas consumption (ton/year)	Gas cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	Power demand (MW)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
CO_2 capture 80%	108 000	91,4	59000	20,7	25.6	91,2	203,3
CO_2 capture 95%	108 000	91,4	15000	5,3	30.4	108,3	205,0

One of the main concerns of absorption technology is the large equipment necessary when the pressure is low and the flow rates are high. The concerns regarding large-scale applications are however not as relevant for CO_2 capture from the exhaust gas from the furnaces as it is for power production (gas turbines). The flow rate of exhaust gas from the furnaces is approximately a third of the exhaust flow rate from the gas turbines at Melkøya, and smaller equipment is therefore required. The amount of CO_2 for capture from the furnaces is then also approximately one third of that from the CHP. The exhaust gas from furnaces does also have higher CO_2 concentration, since the combustion can be performed with lower excess air. The higher concentration makes easier to capture the CO_2, For large amounts of CO_2 captured, the most realistic alternatives is to store the CO_2 in a reservoir. The power requirements and costs related to compression, transport and storage of the CO_2 has not been accounted for in Table 3-3.

Figure 3-4 shows cost estimates for onshore and offshore pipeline transport of CO_2 (high and low range). This figure verifies that the specific cost for pipeline transport becomes very high for the amount of CO_2 captured from the furnaces. In addition, cost of compression and injection has to be included.

Figure 3-4. CO_2 transport cost [7]



The total capital investment cost for CO_2 capture, transport and storage for the Sleipner project and the Snøhvit project was 94 and 191 million USD [**7**]. Sleipner has an annual injection rate of 1 million ton of CO_2, and Snøhvit 0.7 million tons.

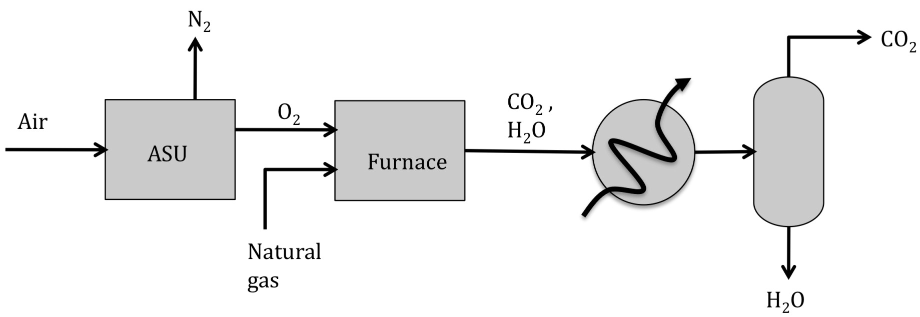
The captured CO_2 could also be used for EOR. Smaller amounts could be sold for use in the food industry. The captured amount of CO_2 from the furnaces is relatively small compared to capture from e.g. the CHP, and it might be relevant to sell the CO_2 instead of storing it in a reservoir. Avoiding transport pipelines and injection systems is desirable, as it is expected to be very costly.

3.3 Oxy-fuel furnaces with carbon capture

Oxy-fuel combustion refers to burning a fuel with pure or almost pure oxygen instead of air. This technology has several advantages compared to air-combustion of fuels, especially with respect to CO_2 capture.

The main advantage with oxy-fuel combustion is that when burned with pure oxygen, hydrocarbon fuels, such as natural gas, generate an exhaust gas consisting of mostly CO_2 and steam. The steam can easily be removed by condensation, leaving a CO_2 stream ready for treatment, compression, transport and storage. The principle of oxy-fuel combustion with CO_2 capture is shown in Figure 3-5.

Figure 3-5. Oxy-fuel combustion with CO_2 capture



CO_2 capture after oxy-fuel combustion can reach close to 100% capture efficiency.

Approximately the same energy is released when burning a fuel with pure oxygen as compared to with air, but since the nitrogen is not heated, higher flame temperatures are obtained. Specialized furnaces are required to handle the high temperatures. The temperatures reached are however not necessary to heat the hot oil at Melkøya to 260°C, and results in exergy-losses.

At the present time, oxy-fuel combustion technology is not applicable to gas turbines, because the mechanical equipment doesn't tolerate the high temperatures. However, for furnaces, the high temperature does not impose a significant problem. Oxy-fuel furnaces are used in the aluminium, iron, steel and glass melting industry, because of the high temperatures generated. The CO_2 is generally not captured. In order to reduce the temperature, and to increase the CO_2 content of the exhaust gas, recirculation of the exhaust gas could be a solution.

Other advantages are lower NO_X production due to reduced nitrogen content, and significantly reduced flue gas flow rate, which means that smaller equipment can be used.

In practical applications the exhaust gas will typically have a CO_2 content of 80-98% after water removal, depending on fuel used and the particular oxy-fuel combustion process [**7**]. Since the CO_2 is transported in pipeline as a dense supercritical phase it is necessary with a very low content of inert gases, and purification of the CO_2 stream might be necessary if the content of impurities are too high for transport.

The major drawbacks of oxy-fuel combustion are the cost and energy requirements related to production of oxygen by separation from air. The most common technology is cryogenic air separation. The air is purified, and cooled under pressure, oxygen and nitrogen is then separated in a distillation column. Cryogenic air separation is currently the most energy- and cost-efficient technology, and it is capable to deliver the largest amounts of oxygen and at the highest purity [**12**][**13**]. Other technologies include membrane technology and pressure-swing adsorption (PSA).

Stoichiometric combustion of the assumed gas composition requires approximately 1276 tons of O_2 /day.

The specific power consumption is dependent on the scale of the O_2 production and purity. For a low-pressure tonnage (> 100 tons/day) cycle producing oxygen at just above atmospheric pressure, the power consumption is approximately 0,3kWh/Nm^3 or approximately 0.22 kWh/kg O_2 [**13**]. For large-scale production of several thousand tons of 0_2 per day, the power requirement is in the range of 220 – 245 kWh/ton O_2. For production between 500 and 1000 tons per day, the requirements are 340 – 280 kWh/ton O_2 [**14**].

The resulting power demand for producing the necessary O_2 is approximately 13.3 MW. This is an increase of 6.2 % compared to the existing power demand. This additional power demand has to be imported from the grid.

Oxy-fuel combustion technology has the possibility to more or less eliminate the CO_2 emission from Melkøya, with a relatively small energy penalty, nearly half the extra energy requirements for post-combustion carbon capture discussed in the previous section, which also has a lower capture rate.

Table 3-4. Oxy-fuel furnaces with CO_2 capture

	Gas consumption (ton/year)	Gas cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	Power demand (MW)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Oxy-fuel furnaces w/ CO_2 capture	108 000	91,4	≈ 0	0	13.3	47,4	138,8

Energy requirements and cost related to compression/pumping, transport and storage of the CO_2 has not been accounted for. Cost of transport/storage of CO_2 is discussed in the previous section.

Investment cost for installation of an air separation unit is also required.

The simultaneously produced Nitrogen from the ASU can be sold as a by-product or used for EOR.

3.4 Furnaces fired with biomass and/or waste

The heat could also be produced in furnaces fired with biomass and/or waste. The technology for bio-heat and waste incineration is regarded as mature.

3.4.1 Biomass

Biomass is a renewable energy resource, and can be regarded as CO_2 neutral when CO_2 emissions related to transport and production are neglected.

Biomass is used to produce solid, liquid and gaseous bio-fuels. With respect to large-scale heat production, solid biomass is the most relevant alternative. Examples are products with low degree of refinement such as wood, bark and wood chips (forest residues) or more refined products such as wood briquettes and wood pellets. The refined products have a higher refining cost, but the benefits are a combustion facility with better operability, better overall combustion, along with better storage stability and efficient logistic [**15**].

All wood products contain some water, which reduces the heating value of the fuel. The effective heating values of selected wood products are given in Table 3-5. The effective heating value denotes the available heat from the fuel after the water has been evaporated.

Table 3-5. Solid bio-fuel properties [15]

Product	Water content	Specific weight	Effective heat value	Effective heat value
	%	kg/m^3	MWh/ton	MWh/m^3
Wood, birch	20	430	4,1	1,76
Wood, spruce	20	345	4,1	1,41
Wood chips, pine	55	390	1,9	0,73
Wood chips, spruce	55	355	1,9	0,69
Industrial chips, raw	55	300	1,9	0,55
Industrial chips, dry	20	200	4,1	0,82
Planer chips	15	100	4,6	0,46
Sawdust	44	230	2,7	0,63
Return logs	20	265	3,8	1
Pellets	8-12	650	4,8	3,1
Briquettes	10-12	600	4,3	2,6
Wood powder	5	280	4,9	1,4
Bark	55	280	2,1	0,6

The best fuel alternative depends on various factors such as size and type of combustion equipment, availability and price of the different fuel types and qualities, available storage area and requirements with respect to emissions. The prices for selected fuel types are given in Table 3-6.

Table 3-6. Prices on selected bio-fuels [16]

Product	Price, øre/kWh	Price kr/ton
Briquettes	17,4	785
Pellets	30	1448
Forest chip	19,5	-
Chips from demolition waste	7,8	-
Planer chips, sawdust	9,3	-
Bark	5,8	-

A complete bio-fuel combustion plant consists of fuel storage, equipment for handling and feeding the fuel, a furnace or a boiler, and equipment for flue gas treatment and ash handling. The technology used is dependent on the size of the plant. For large plants (>5 MW) the most common technology is use of movable grate, and furnaces where the combustion is carried out in two steps; first using a carburettor and then combustion in a circulating fluidized bed (CFB) [**17**]. The two-step system gives better flexibility concerning fuel water content, and the sand in the CFB ensures more even temperature distribution in the combustion zone, which improves the overall combustion.

The plant efficiency has a large impact on the fuel consumption and thereby fuel cost. The efficiency is dependent on fuel type, combustion technology, operating conditions, and dimensions. Bio-fuels contain components such as Chlorine, Sodium and Potassium that causes fouling and corrosion on heat surfaces at high temperatures, which reduces the efficiency. Using "pure" fuels can reduce this problem. "Pure" fuels do however have a higher cost.

Burning bio-fuels results in more local pollution than burning natural gas due to higher content of particulates, NO_X and PAHs in the flue gas. Flue gas treatment could be necessary. To evaluate the total environmental impact of burning bio-fuels, CO_2 emissions related to refining, handling and transporting the bio-fuel should also be assessed.

There are no bio heat plants in Norway that are comparable to the large-scale heat production necessary at Melkøya. The largest bio heat facility in Norway is located at Gardermoen, with a production capacity of only 13 MW. The heat is used for district heating [**18**]. The world's largest biomass-fired power plant is located in Finland. This power plant produces 240 MW of electricity, 100 MW of process steam and 60 MW of heat for district heating. The typical fuel composition is 45% wood based biomass, 45% peat and 10% coal [**19**].

The large-scale heat production necessary at Melkøya requires a bio-heat production facility with good operability and high efficiency. Pure, refined fuels suitable for automation such as wood chips, pellets or briquettes are therefore favourable.

A major concern is the large amount of fuel necessary at Melkøya, and the local availability, as it is desirable to avoid transport over long distances.

Another concern is that heat production with solid fuels generally requires more effort to operate than heating with liquids, gas or electricity.

Table 3-7 shows the necessary biomass needed for combustion of pine wood chips, pellets and briquettes to cover the heat demand at Melkøya. The biomass demand is in the range of 200 – 860 containers per week.

Table 3-7. Furnaces fired with biomass

	Biomass consumption (ton/year)	Biomass consumption (m^3/year)	Biomass cost (mill.NOK/year)	CO_2 emission (ton/year)	CO_2 cost (mill.NOK/year)	Electricity cost (mill.NOK/year)	Total cost (mill.NOK/year)
Furnace fired with pine wood chips	870 000	2 231 000	330,7	0	n/a	n/a	330,7
Furnace fired with pellets	344 000	530 000	496,0	0	n/a	n/a	496,0
Furnace fired with briquettes	384 000	641 000	287,7	0	n/a	n/a	287,7

The required mass of pellets and briquettes does by far exceed the produced quantity in Norway, 44 800 and 38 700 tons respectively in 2007 [**16**].

In June 2010, Europe's largest, and the world's second largest factory for production of wood pellets will open outside Kristiansund. The factory will produce 450 000 tonnes of pellets annually. The raw material is 1.2 million m^3 wood chips imported from USA, Canada, Liberia, Russia and the Baltic [**20**] [**21**]. A bio-heat facility at Melkøya would require more than 75% of the pellets produced at this factory.

Alternatively, import of large amounts of wood chips or pellets/briquettes are necessary.

An option could be to build an own pellets or briquette factory at, or close to, Melkøya, and import wood chips as raw material. It is however better to have such a factory close to the raw material, and transport the products (pellets/briquettes) over long distances, due to the higher energy density of the products compared to wood chips.

If wood chips can be satisfactory as fuel at Melkøya, it would be just as good to just import wood chips as fuel, and not as raw material for pellets/briquette production.

It is expected to become difficult to secure the amounts of biomass needed to cover the heat demand at Melkøya, without additional firing of fossil fuels like natural gas. In addition, although it is assumed that the biomass fuels are CO_2-neutral, it is unlikely that production and transport of these amounts of biomass can be entirely CO_2 free.

3.4.2 Waste

With the exception of plastics, domestic waste is more or less CO_2 neutral. An additional positive environmental effect is that emissions of methane from waste disposal sites are reduced.

The average heating value of solid waste fuel is 3 kWh/kg [**22**].

The combustion technology for waste incineration is mainly the same as for bio-fuels. Grate combustion is the most common solution for large heat production facilities. Use of fluidized bed is also possible, but since it requires more refined waste, it is not commonly used for large plants. Because of strict requirements to emission, advanced flue gas purification systems are required.

In Norway, a prohibition of waste disposal was initiated in July 2009. Waste combustion companies in Norway have to demand relatively high payments to receive and handle the waste, in order to make it profitable, due to high combustion taxes. These taxes have been removed in Sweden, and they can therefore charge far less for the waste. The result is that Norwegian waste is exported to Sweden. It is not the purpose of the potential waste incineration at Melkøya to be profitable, and it could be possible to charge less or nothing for the waste, and compete with export to Sweden.

As for biomass, it is desirable to avoid long transport distances, due to the related CO_2 emissions.

The required waste to cover the heat demand at Melkøya is given in Table 3-8.

Table 3-8. Furnaces fired with waste

	waste consumption (ton/year)	waste cost (mill.NOK/year)	CO_2 emission (ton/year)	CO_2 cost (mill.NOK/year)	Electricity cost (mill.NOK/year)	Total cost (mill.NOK/year)
Furnace fired with waste	551 100	0	0	n/a	0	0

In 2008, 372 000 tons of domestic waste were disposed at waste disposal sites in Norway [**23**]. This is not enough to cover the total heat demand at Melkøya, and waste from the industry and businesses would have to be included. In 2007, a total of 2 175 000 tons of waste were disposed at waste disposal sites in Norway [**24**]. Only approximately 570 000 tons of this can be regarded as combustible in waste incineration plants.

It is therefore difficult to cover the heat demand at Melkøya with waste incineration, without import of waste. A possibility could be to supplement the waste incineration with wood chips, pellets or briquettes.

3.5 Electric heating

The heat demand could be covered by electricity, by heating the hot oil, and distribute it to the plant.

Applicable to heat production at Melkøya is electric resistance heating, electrode heating and induction heating.

Electric resistance heaters utilize the heat that is produced when electricity is sent through a resistor. The resistor is immersed in the fluid to be heated, heating it directly. An electric resistance heater could be used to heat the hot oil directly, or to produce steam (electric steam boiler). Electric resistance heaters are simple, and highly efficient, with an efficiency of close to 100%.

In an electrode heater, the fluid itself acts as the resistance. The most common application is to produce steam. The electrode boilers also have high efficiency, close to 100%.

Induction heating is the process of heating an electrically conducting material, typically metal, by electromagnetic induction. In an induction heater, an alternating current is passed through an electromagnet, creating an alternating magnetic field. The magnetic field generates eddy currents in the metal and resistance leads to heating of the metal. The heat induced in the metal is transferred to the fluid to be heated by conduction.

From a thermodynamic point of view, using electricity for heating purposes (not in heat pumps) is waste of high-quality energy, since heat at 260°C is of rather low quality.

Use of electricity for heating does however have the advantage of being simple, effective and clean. Electric heating at Melkøya, together with electrification of the power demand has the potential to entirely eliminate the CO_2 emission from Melkøya. On a "global" scale, how the electricity is produced should be taken into consideration, when evaluating the CO_2 emissions related to use of electricity.

It is throughout this report assumed that the electricity mainly is produced from renewable energy resources, such as hydropower, and is therefore CO_2 neutral.

The major drawback of electric heating at Melkøya is the large amount of electricity that would have to be imported from the grid, and the cost related. More than 1,32 TWh of electricity annually is needed to supply Melkøya with the necessary heat, in addition to the more than 1.7 TWh needed to cover the power demand.

The large quantity of electricity needed for full electrification of Melkøya could make it necessary to develop more renewable energy in the region, in order to ensure CO_2 neutral electric power.

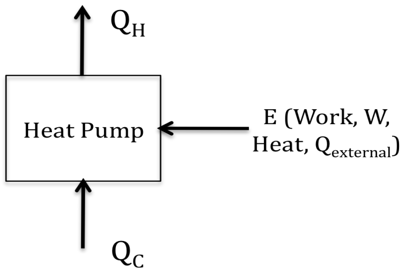
Table 3-9. Electric heaters

	Gas consumption (tonnes/year)	Gas cost (mill.NOK/year)	CO_2 emissions (tonnes/year)	CO_2 cost (mill.NOK/year)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Electric heating	n/a	n/a	0	0	595,2	595,2

3.6 Heat pumps

Heat flows naturally from a higher to a lower temperature. Heat pumps are able to force the heat flow in the other direction, using a relatively small amount of high quality drive energy (electricity, fuel, or high-temperature waste heat). The heat pump principle is illustrated in Figure 3-6.

Figure 3-6. Heat pump principle



This means that heat pumps at Melkøya enable the utilization of low-temperature heat sources, which would normally require cooling, by upgrading the temperature. The temperature-upgraded heat could then be used to cover the heat demand.

Theoretically, the total heat delivered by the heat pump is equal to the heat extracted from the heat source, plus the amount of drive energy supplied.

Equation 1

$$Q_H = Q_C + E$$

The coefficient of performance (COP) is a measure of the effectiveness of the heat pump. The COP is defined as the ratio of the heating effect to the net work or heat required to achieve that effect.

Equation 2

$$COP = \frac{Q_H}{E}$$

The COP decreases rapidly with increasing temperature lift, that is, increased temperature difference between the heat source and heat sink. This can be seen from Equation 3.

Equation 3

$$COP_{max} = \frac{T_H}{T_H - T_C}$$

An overview of the process streams with the largest cooling demand at Melkøya is given in Table 3-10. They represent potential heat sources for heat pumps. The temperatures are relatively low. The heat demanding processes are listed previously, in Table 2-1.

Table 3-10. Potential heat pump heat sources [25**]**

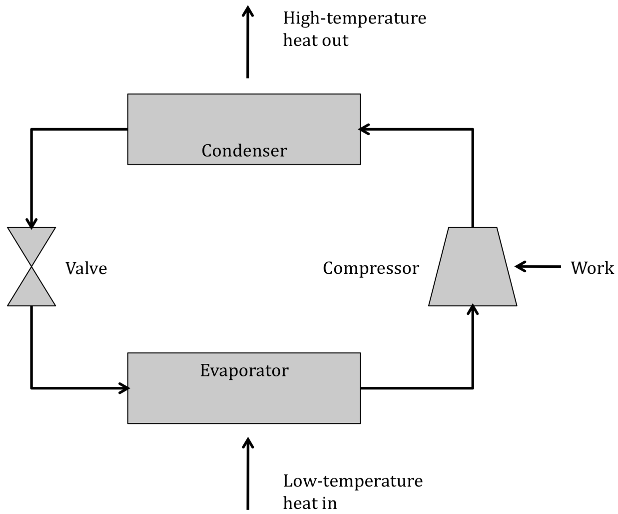
Description	Delivered heat (MW)	Temperature in (°C)	Temperature out (°C)
Lean amine-cooler	35,8	81,1	44,1
Tempered coolingwater	35,1	22,5	10,0
CO_2 drying & compression	6,8	133,1	21,4
Sub-cooling compressor, inter-cooler	13,5	61	9,9
Sub-cooling compressor, after-cooler	28,6	102,3	11,0
Liquefaction compressor, after-cooler	16,4	73,5	10,0
Pre-cooling compressor, after-cooler and condenser	205,5	67,8	10,0
Gas pre-treatment, pre-cooler	6,2	26,9	12,9
Stabilized condensate	6,3	140,5	17,0
Total	**354,2**		

The low temperature heat sources, and high temperature lifts are the main challenges for use of heat pumps at Melkøya, and in the industry in general.

The most common industrial heat pumps are closed-cycle compression (CCC) heat pumps and mechanical vapour recompression systems (MVRs). Other heat pump alternatives that are not so commonly used for industrial purposes are absorption heat pumps and heat transformers (HT). A more recent development that is relevant for industrial purposes is a hybrid heat pump.

The CCC heat pump consists of a valve, compressor and two heat exchangers referred to as evaporator and condenser. The components are connected in a closed circuit. The working fluid circulates through the four components. A principal sketch is shown in Figure 3-7. In the evaporator, the working fluid evaporates at a temperature below that of the heat source, causing the heat to flow from the heat source to the fluid as it evaporates. The vapour is then compressed to a higher pressure and temperature in the compressor. The compressor is usually driven by an electric motor. In the condenser, the hot vapour condenses and rejects useful heat at a higher temperature than the heat source. The high-pressure working fluid is then expanded through the valve before entering the evaporator again.

Figure 3-7. Closed-cycle compression (CCC-) heat pump



The MVR heat pumps are, as the CCC heat pump, based on vapour compression. The difference is that the MVRs use vapour from the process as working fluid. The MVR heat pumps are classified as open or semi-open. In open systems, vapour from the industrial process is compressed to a higher pressure and thus a higher temperature, and condensed in the same process rejecting heat. In semi-open systems, which are the most common solution, heat from the recompressed vapour is transferred to the process via a heat exchanger. MVR systems can work with heat source temperatures of 70-80°C and deliver heat between 110°C and 150°C [**26**].

The hybrid heat pumps are a combination of compression heat pumps, and absorption heat pumps, and are also known as vapour compression heat pumps with solution circuits or absorption/compression heat pumps. IFE/ Hybrid Energy has commercialized a hybrid heat pump a 50/50 solution of water and ammonia as working fluid, and is especially suitable for exploitation of waste heat from industrial processes. The design operating conditions are heat sources at 50°C and heat delivered at 100°C, with a COP of 3 [**27**].

When investigating use of heat pumps at Melkøya, a CCC-heat pump is used as basis. This heat pump requires a working fluid, and choice of working fluid is discussed later in this section.

It is unlikely that heat pumps alone can cover the total heat demand at Melkøya. Currently available heat pumps are not able to supply heat at the temperatures of the hot oil system, and installation of a heat pump for each of the heat demanding processes is unrealistic with respect to amount of equipment/machinery and operability.

It might however be realistic to select some of the heat demanding processes to be supplied with heat from heat pumps, while the hot oil heated by some means of heat generation covers the remaining heat demand.

In general it would be natural to look at the processes with largest heat demand at the lowest temperature, and combine this with a process giving off a large amount of heat at a high as possible temperature. This way the heat pump would benefit the most, with the best COP.

One of the most obvious choices is the CO_2 removal process. This heat demand of 76.5 MW constitute almost 50% of the total heat demand, and supplying this heat using a heat pump would significantly reduce the need for heat from the hot oil. The result would be reduced need for gas, biomass, waste, or electricity, and potentially CO_2 emissions.

In agreement with the supervisors, it is assumed that the CO_2 removal process requires heat at approximately 115°C. Assuming that ΔT_{min}=5°C gives a suitable trade-off between investment cost and operating cost, the heat pump condenser would have to be operated at minimum 120°C.

A possibly suitable heat source is the pre-cooling compressor after-cooler and condenser. Utilizing the heat rejected by this process down to 10°C, the heat pump evaporator would have to be operated at 5°C. The maximum obtainable COP for a heat pump operating between 120°C and 5°C is 3.42.

The heat pump will not operate as ideal, and the COP is likely to be significantly lower. The deviation from the maximum COP is a result of losses in the process such as non-isentropic compression, heat exchanged through a finite ΔT in the condenser/evaporator, and un-restrained expansion in the valve.

Another heat source option could be the lean amine cooler. Here the heat is rejected at higher temperatures, giving a higher COP potential (4.85).

As mentioned previously, a challenge when using CCC heat pumps is to find suitable working fluid.

The temperatures of the heat source and the heat sink govern the temperatures and operating pressures of the working fluid in the evaporator and condenser. It is generally desirable to avoid excessively low pressures in the evaporator, and excessively high pressures in the condenser.

Until the 1990s, the CFCs (Chlorofluorocarbons) were the governing working fluids. They are now prohibited due to their Ozone depletion potential. HCFCs (Hydrochlorofluorocarbons) then became substitutes, but are now in process of being phased out as well. Currently, HFCs (Hydrofluorocarbons) can be considered long-term working fluids, together with natural working fluids [**28**].

Examples of natural working fluids are Ammonia, hydrocarbons, carbon dioxide and water.

Ammonia is thermodynamically and economically an excellent alternative to CFCs and HCFCs. Ammonia is not yet used in high-temperature industrial heat pumps because there are currently no suitable high-pressure compressors available. If efficient high-pressure compressors are developed, ammonia will be an excellent high-temperature working fluid [**28**].

Water is an excellent working fluid for high-temperature industrial heat pumps. It has favourable thermodynamic properties, and is neither flammable nor toxic. Major disadvantages are that water has low volumetric heat capacity, resulting in large volumes and compressors especially at low temperatures, and that at temperatures below 100°C, the pressure is below atmospheric.[**28**]

A mixture of Ammonia and water might benefit from the properties of both the fluids.

Carbon dioxide is a potentially strong refrigerant that has gained attention. It is non-toxic and non-flammable [**28**]. It is however not suitable for heat deliveries at high temperature, as the critical temperature is only 31°C [**29**].

Hydrocarbons are well known working fluids with favourable thermodynamic properties. Presently, Propane, Propylene and blends of Propane, Butane, Iso-butane and Ethane are regarded as the most promising hydrocarbon working fluids in heat pumping systems [**28**]. Several of these hydrocarbons are available at Melkøya. As single component, Ethane, Propane and Propylene cannot be used to deliver heat at 120°C for the CO_2 removal process at Melkøya. Alone, or in combination with the rest, butane or Iso-butane might be suitable. Due to the flammability of the hydrocarbons, use of these in heat pumps requires extra pre-caution.

Assuming that a COP larger than 1 is obtainable, use of heat pumps at Melkøya could mean significant savings in fuel or electricity consumption and CO_2 emission, depending on what heat generation solution the heat pumps are combined with, e.g. furnaces fired with natural gas or biomass or electric heaters.

Assuming that a COP of 2 is obtainable for a heat pump delivering 76.5 MW of heat to the CO_2 removal process, the result is as given in Table 3-11.

Table 3-11. Use of heat pump

	Fuel consumption (ton/year)	Fuel cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	Power demand (MW)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Heat pump + gas fired furnaces	59 000	49,5	159000	55,7	38.3	136,3	241,5
Heat pump + electric heaters	n/a	n/a	0	0	129.0	459,8	459,8
Heat pump + pellets fired furnaces	187 000	268,8	0	0	38.8	136,3	405,1

In combination with gas- or biomass-fired furnaces, a heat pump supplying the CO_2 removal with heat would reduce the fuel consumption by 45.8%. The heat demand of 76.5 MW from the hot oil is then replaced with a power demand of less than 76.5 MW, dependent of the obtained COP. In combination with electric heaters, the savings in electric power requirements will be the difference between 76.5 MW and the new power requirement of heat pump compressor.

In this section, only one heat pump option has been investigated. There are multiple combinations of heat sources and heat sinks that potentially also could be covered by heat pumps, resulting in even more savings.

3.7 Preliminary evaluation of the alternatives

In this section, the heat generation alternatives are summarized and evaluated. They are ranked with emphasis on thermodynamic advantages, but also CO_2 emissions and practical limitations are taken into consideration.

Heat pumps are thermodynamically and theoretically the clearly best alternative, as it replaces as heat demand with a smaller power demand. It might however be difficult to find a practical solution. The relatively high temperatures and high temperature lifts make it difficult to obtain a good COP.

It is found that it is unrealistic that heat pumps can cover the total heat demand at Melkøya, and heat pumps have therefore only been assessed as a potential <u>part</u> of a heat generation solution at Melkøya, in combination with other means of heat generation such as gas- or biomass-fired furnaces or electric heaters. Supplying the heat needed for the CO_2 removal process with heat pumps has been identified as a promising solution, which might significantly reduce the fuel/electricity consumption and CO_2 emissions. This is however not necessarily the only potential heat pump usage at Melkøya, and other alternatives should therefore also be assessed.

The combustion solutions are thermodynamically the second best alternatives. They do however generate higher temperatures than necessary to heat the hot oil. Not utilizing this high temperature energy results in exergy losses, meaning that the full thermodynamic potential is not taken advantage of. This could be avoided by extracting some work, but this has not been assessed.

Burning natural gas in furnaces to generate heat is a fairly simple solution, utilizing mature, well-known technology with high efficiency. The reduction in fuel consumption and CO_2 emission is good compared to the existing energy plant, but the emissions are perhaps not sufficiently reduced to justify the electrification investments. If the goal is only to reduce the emissions from Melkøya, the reduction in the CO_2 emission from this heat generation alternative might be satisfactory. However, if it is aimed at zero CO_2 emission from Melkøya, this heat generation alternative comes to short.

The emissions from the furnaces could be further reduced by CO_2 capture from the exhaust gas. But due to the increase in energy requirements, the overall efficiency is reduced. It also imposes a significant cost.

CO_2 capture from the exhaust gas from the furnaces has advantages over capture from power plants; the CO_2 concentration is higher, and the flow rates are lower.

Absorption technologies using amine or carbonate solvents have been evaluated. The potential capture efficiency is good, 80-95%, but the cost, the energy requirement for regeneration of the solvents, and potential negative health and environmental effects reduce the attractiveness of the absorption technologies. As of today, amine absorption is the most technically mature option.

Oxy-fuel combustion significantly simplifies the CO_2 capture, but the production of oxygen is power demanding. The power demand of approximately 13.3 MW has to be imported from the grid. This power demand is however smaller than for CO_2 capture by amine absorption, and in addition, a higher capture rate is achievable, close to 100%.

In addition to the CO_2 capture it self, either by absorption or oxy-fuel combustion, energy requirements and cost related to compression/pumping, transport and storage of the CO_2 has to be accounted for. The cost of finding a suitable reservoir for the CO_2, as well as facilities for compression, transport and injection is expected to become very high.

Combustion of biomass or waste is in principle a good and interesting alternative for producing heat. The technology is relatively mature, and is used for heat generation for industrial purposes and district heating. Burning of biomass or waste has somewhat lower efficiency than combustion of natural gas, and the local emissions are also higher. Very large amounts of biomass/waste are needed to cover the heat demand at Melkøya, and import is necessary. A more thorough assessment of related CO_2 emission is necessary in order to evaluate if biomass or waste then can be regarded as CO_2 neutral.

From a thermodynamic point of view, electric heating of the hot oil is a complete waste, as high quality energy (electricity) is transformed to low quality energy (heat at 260°C). The technology is however well known and simple, with high efficiency. It would require a large additional amount of power imported from the national grid. Electricity is also relatively expensive. From an operability perspective, it might be beneficial with full electrification of Melkøya.

3.7.1 Promising scenarios

Based on the assessment of the suggested heat generation alternatives, the following is found to be interesting and promising as heat generation solutions at Melkøya in case of electrification.

1. Heat pumps utilizing process waste heat – the thermodynamic benefits suggests that heat pumps should be a part of a heat generation solution, regardless of what other options it is combined with (gas- or biomass-fired furnaces, electric heaters).
2. Biomass (e.g. pellets) in combination with heat pumps - With enough heat covered by heat pumps, use of biomass could become a more realistic option.
3. Furnaces fired with natural gas – a simple, efficient and thermodynamically sound solution that might give sufficient reductions in CO_2 emissions.
4. Oxy-fuel furnaces with CO_2 capture – despite additional energy requirements and high cost, it has displayed benefits over absorption technology that makes it interesting.
5. Electric heating – although disfavoured by the thermodynamics, it is a simple, efficient heat generation method resulting in zero CO_2 emission from Melkøya.

4 Simulations

The three heat generation options furnace fired with natural gas, oxy-fuel furnaces with CO_2 capture and heat pump utilizing process waste heat to cover the heat demand of the CO_2 removal process, are selected for simulations.

In this section, the simulation of the chosen heat generation alternatives are described. A description of the modelling of each of the cases is given, before the results are presented and discussed.

The purpose of the simulations in general is to calculate the CO_2 emissions to air, and the utility need for each of the selected heat generation alternatives, but other results are also of interest in order to evaluate the options. E.g. for a heat pump, interesting parameters are heat delivery capacity, COP and power demand. For the combustion of natural gas with oxygen, required amount of O_2 and the power necessary to produce it is relevant to assess, as well as power needed for compression and pumping the CO_2.

PRO/II® is selected as process simulation tool. PRO/II® is a steady-state process simulator from Invensys Process Systems (IPS). Peng-Robinson (PR) is selected as equation of state.

Because three alternatives are selected for simulation, the level of detail is not very high.

4.1 Furnaces fired with natural gas

The basis for these simulations are furnaces supplied with natural gas available at Melkøya. The combustion process can be performed with both air and pure oxygen (oxy-fuel combustion). The furnaces shall supply the hot oil with 167.2 MW of heat.

The purpose of the simulations is mainly to identify the fuel gas consumption and the CO_2 emission. In the case of oxy-fuel combustion it is also relevant to determine the O_2 demand, in order to calculate the energy needed to produce the oxygen. It is also relevant to estimate the power needed to compress the CO_2 for transport and storage.

For the combustion with pure oxygen, the O_2 production has not been simulated.

4.1.1 Modelling

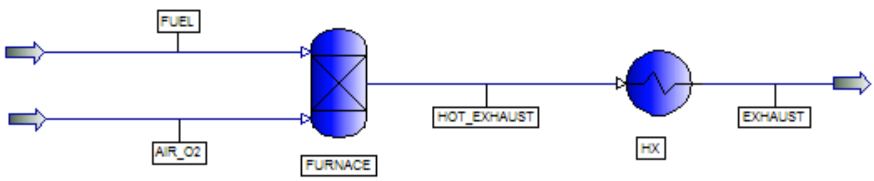
The combustion process is modelled with a Gibbs-reactor acting as the furnace(s). The reactor has two inlet streams, one for the fuel gas, and one for air or oxygen.

The reactor is specified to have constant duty equal to zero.

The cooling of the hot exhaust gas is modelled simply as a single heat exchanger, that is, how the hot oil system is configured has not been taken into consideration.

The simulation model is shown in Figure 4-1.

Figure 4-1. Gas fired furnace simulation model



The hot oil is assumed to return from the consumers at approximately 140°C. The hot exhaust can therefore not be cooled further than to 145°C, assuming ΔT_{min}=5°C.

The exhaust is therefore specified to have a temperature of 145°C at the heat exchanger outlet, and the mass flow rate of fuel (and air/O_2) is adjusted to give a duty of 167.2 MW, the heat required from the hot oil system.

The energy not utilized below 145°C could be used for other purposes. It is however beneficial that the exhaust gas is warmer than the ambient temperature, so that it will rise.

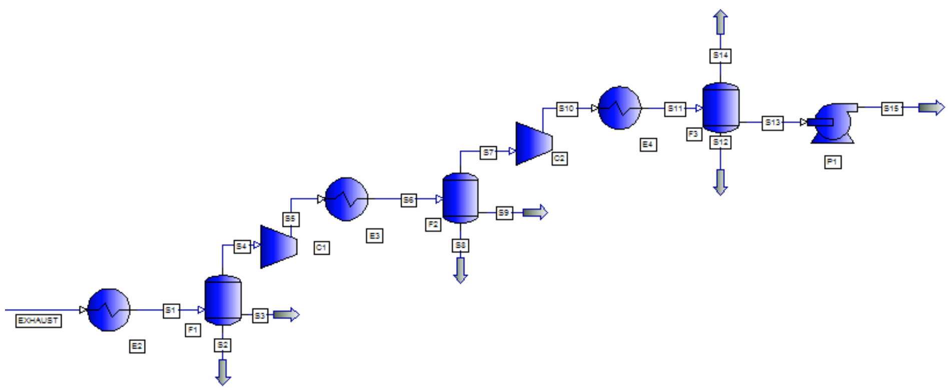
In the case of oxy-fuel combustion, the exhaust gas has to be cooled further, in order to condense the water. The exhaust is then compressed and cooled in two steps to remove the water. After the last compression step, it expected that drying by e.g. adsorption in molecular sieve is necessary to obtain sufficient dryness, before the CO_2 is cooled to liquid. This is however not simulated. A pump then further pressurizes the liquid CO_2.

Recirculation of the exhaust gas to reduce the temperatures and increase the CO_2 concentration has not been simulated.

To what pressure the CO_2 is compressed/pumped, is dependent on the transport distance and the reservoir. The pressure in the reservoir increases with time.

CO_2 is transported in pipelines as a dense, supercritical phase. It is assumed that it is compressed to 60 bar, and pumped further to 100 bar. The demand for cooling water and the corresponding power demand has not been calculated.

Figure 4-2. CO_2 compression simulation model



4.1.2 Combustion with air

The air is assumed to consist of 21% Oxygen and 79% Nitrogen. Air enters the combustion chamber at atmospheric pressure and 4°C. The fuel gas is assumed to enter at the same conditions.

The reaction is assumed to be stoichiometric and complete, as given in Equation 4.

Equation 4

$$95CH_4 + 4C_2H_6 + 1N_2 + 204(O_2 + 79/21N_2) \Rightarrow 103CO_2 + 202H_2O + 5379/7N_2$$

Equation 4 gives an air-fuel ratio of 9.71 kmole air per kmole fuel or 16.76 kg air per kg fuel.

A figure of the process, along with stream data from PRO/II® are found in Appendix B.1.

4.1.3 Oxy-fuel combustion and CO_2 capture

It is assumed that the oxygen stream consists of 100% pure O_2. In practise, it would contain some Nitrogen. It is cheaper to produce less pure oxygen, but more effort would have to be spent on removing other components from the exhaust gas, as it would not consist of CO_2 and water only.

Pure oxygen and fuel enters the combustion chamber at atmospheric pressure and 4°C, and the reaction is assumed to be stoichiometric and complete, as given in Equation 5.

Equation 5

$$95CH_4 + 4C_2H_6 + 1N_2 + 204O_2 \Rightarrow 103CO_2 + 202H_2O + 1N_2$$

Equation 5 gives a stoichiometric O_2 demand of 2.04 kmole per kmole fuel, or 3.9 kg O_2 per kg fuel.

As discussed in section 3.3, the energy demand for producing pure oxygen ranges from 0.22-0.34 kWh/kg. In these simulations, 0.25 kWh/kg has been used to calculate the power demand.

A figure of the process, along with stream data from PRO/II® are found in Appendix B.2 and Appendix B.3.

4.1.4 Results and discussion

Table 4-1 and Table 4-2 shows the results from the simulations of the furnaces fired with natural gas and the oxy-fuel furnaces with CO_2 capture.

Both cases display a significant reduction in fuel consumption, and thereby CO_2 emission to air/for capture, compared to the existing energy plant.

Combustion with air

For the air/fuel furnaces, the result is a reduction in CO_2 emission of approximately 70% compared to the emission permit.

The exhaust temperature is above 2000°C. The total effect in is 177.3 MW. 167.2 MW is utilized, giving an efficiency of 94.3%, when no heat loss is assumed.

Table 4-1. Combustion with air – Simulation results

Fuel gas consumption	CO_2 emission to air
ton/year	ton/year
103000	280000

Oxy-combustion and CO_2 capture

The result of combustion with pure oxygen is 269 000 tonnes per year of CO_2. This is subject to capture, purification, compression, transport and storage.

The consumption of fuel gas is reduced, and by CO_2 capture the CO_2 emission to air is more or less eliminated. The "cost" is increased power demand, as power is needed for O_2 production and compression and transporting the captured CO_2.

The O_2 required for stoichiometric combustion of the natural gas is 1172 tonnes/day. In practice, the O_2 demand will be somewhat higher, as excess O_2 is necessary to ensure complete combustion.

The effect in is 170.3 MW, resulting in an efficiency of 98.2% when neglecting heat losses.

Extremely high temperatures are generated, almost 4450°C.

The estimated power demand for producing the necessary O_2 is 12.2 MW. Approximately 3.6 MW is needed for compression of the CO_2 and pumping it into a reservoir. In addition, some power for pumping cooling water etc., and heat for regeneration of the CO_2 dryers should be expected.

Despite assumed stoichiometric and complete combustion, the exhaust gas contains some Nitrogen. This is due to the Nitrogen content of the fuel gas.

As discussed in section 3.3, in practical cases, the exhaust will also contain other elements that would have to be removed.

Table 4-2. Oxy-fuel furnaces w/CO_2 capture – Simulation results

Fuel gas consumption (ton/year)	CO_2 for capture/storage (ton/year)	CO_2 comp.power demand (MW)	O_2 consumption (ton/year)	O_2 prod.power demand (MW)
99 000	269 000	3.6	387 000	12.2

Cost

The reduced fuel consumption leads to significant reductions in fuel cost.

In the case of air/fuel combustion, the reduced CO_2 emission to air also results in lower CO_2-emission cost.

When burning the natural gas with pure oxygen, the cost of CO_2 emission is entirely eliminated; instead a cost related to the increased power demand, has to be accounted for.

In addition, there are investment costs related to furnaces, air separation plant, re-piping, new heat exchangers, CO_2 compressors/pumps, transport pipelines and injection system.

Improvements – future work

Some assumptions have been made that are somewhat unrealistic.

One example is no heat loss from the furnaces. With the high temperatures generated, there will be some heat losses. Taking actual losses such as the heat loss into account would reduce the efficiency, and lead to somewhat higher fuel consumption in order to deliver 167.2 MW. The result would be higher CO_2 emission or more CO_2 for capture/storage, higher O_2 demand and thereby higher power demand.

Another example is the assumptions of complete, stoichiometric combustion. This is difficult to obtain, and some excess air/oxygen, as well as formation of other components than CO_2 and water should be expected. These impurities will have to be removed to some degree.

The combustion processes are modelled with only one furnace as well as a single heat exchanger heating the hot oil. Most likely, there will be more than that. Taking the actual hot oil system into consideration, it might be possible to optimize with respect to the temperature levels.

The return temperature of the hot oil affects the efficiency and fuel consumption. If the hot oil returns at a higher temperature than assumed, the result would be higher fuel consumption, and lower efficiency. Allowing a smaller ΔT_{min}, the result is the opposite.

4.2 Heat pump utilizing process waste heat

The motivation for the heat pump simulations is to determine if a heat pump using waste heat from different heat sources at Melkøya could cover the heat demand of the CO_2 removal (amine regeneration) process. This process needs 76.5 MW of heat at approximately 115°C.

The heat pump itself does not emit any CO_2, and is not expected to cover the entire heat demand at Melkøya. It is therefore instead aimed to identify the potential it has to reduce CO_2 emission when implemented together with other options.

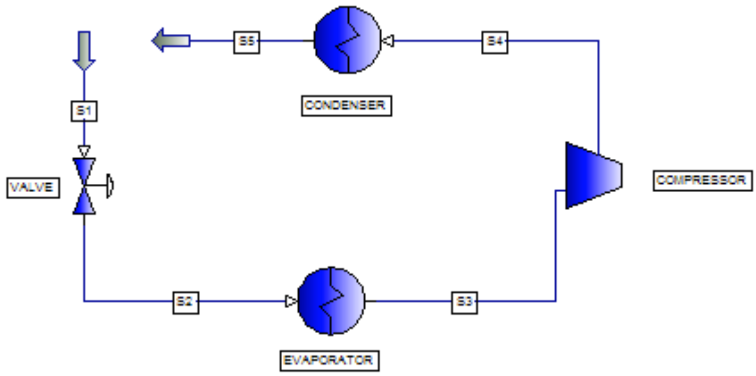
The pre-cooling cycle (PCC) compressor after-cooler, and the lean amine cooler are selected as the two potential heat sources. Both normally reject heat to seawater.

Further, n-butane (R600) is chosen as working fluid in the heat pump, on the basis of the evaluations made in section 3.6. N-butane evaporates and condenses at reasonable pressure levels with the given heat sources and heat sink.

4.2.1 Modelling

The heat pump is modelled as a CCC-heat pump, consisting of a compressor, valve, an evaporator and a condenser. The heat pump simulation model is illustrated in Figure 4-3.

Figure 4-3. Heat pump simulation model



In stream S1, the fluid composition and mass flow rate is defined. The condensation temperature and the bubble point pressure specify the condition of working fluid.

The valve outlet pressure is specified equal to the vapour pressure of the evaporation temperature.

The evaporator duty is specified based on the heat source.

The compressor is assumed to have a polytropic efficiency of 85%. The outlet pressure is specified, equal to the vapour pressure of the working fluid at the condensation temperature. In order to reduce the work, compression is often performed in more than one step, with inter-cooling. Because of the shape of the n-butane phase curve, it is difficult to avoid entering the two-phase region in one of the compressors. It was attempted with compression in two steps with inter-cooling, but it was found to be little or nothing to gain.

The condenser is specified to condense the working fluid completely, that is "hot product liquid fraction" is set to 1.

For the heat exchangers (evaporator/condenser), it is assumed that ΔT_{min} = 5°C gives an appropriate trade-off between investment cost and operating cost. In the condenser, it is assumed that the heat is exchanged directly with the heat demanding process (the CO_2 removal).

It is assumed no pressure drop in the piping and heat exchangers.

4.2.2 Case 1 – Pre-cooling compressor after-cooler as heat source

The pre-cooling cycle is the first step in the refrigeration process at Melkøya. After evaporating while drawing heat from the natural gas, the pre-cooling fluid is compressed in a compressor, before it enters the after-cooler (and condenser) and rejects heat to seawater.

The pre-cooling fluid composition is assumed to consist of 60% Ethane and 40% Propane. The pressure (19.202 bar) is decided based upon that the fluid should be entirely condensed at 10°C. The mass flow rate is then calculated by a controller to be 471.968 kg/s, on the basis that 205.5 MW of heat is rejected when the fluid is cooled from 67.8°C to 10°C in the after-cooler and condenser. See Appendix B.4.

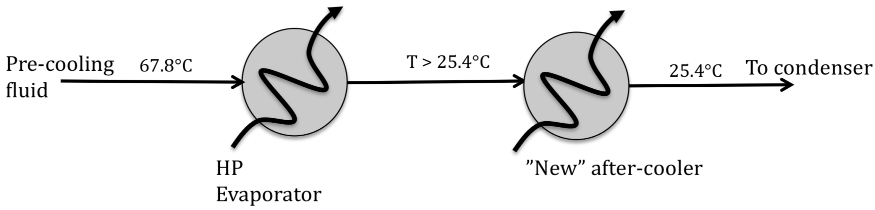
As expected, most of the heat is rejected in the lower end of the temperature interval, when the fluid condenses. The condensation starts at 25.4°C. This gives an after-cooler duty of 42.5 MW (and pre-cooling condenser duty of 163 MW). See Appendix B.5.

The pre-cooling condenser could also be used as heat source in the heat pump, but it is not desirable to utilize the entire temperature interval down to 10°C, because of the large temperature lift, and thereby low COP. Also, it is not necessary in order to cover the CO_2 removal heat demand.

There are two different possible configurations when using the PCC compressor after-cooler as heat source; a series solution, and a parallel solution.

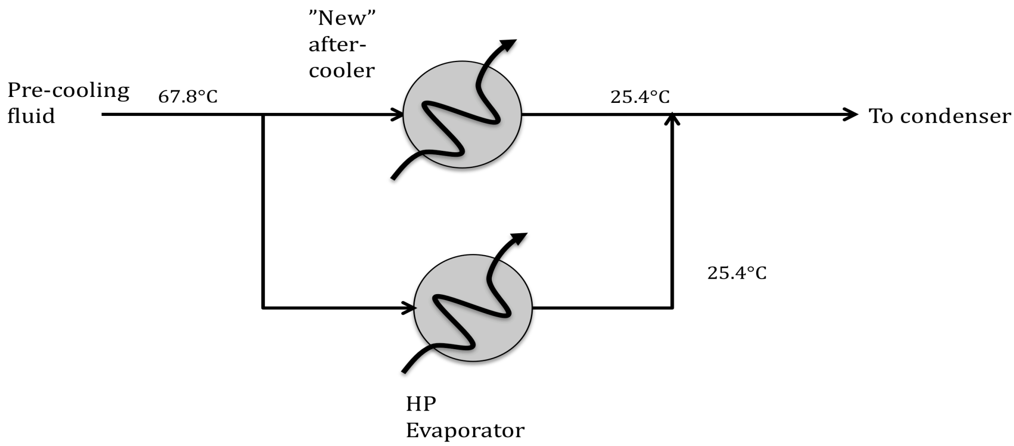
In order to avoid a too high temperature-lift in the heat pump, the existing after-cooler could be replaced with two separate units in series, one acting as the heat pump evaporator, and one as the “new” after-cooler. The evaporator cools the pre-cooling fluid to a temperature higher than the condensation temperature, and the after-cooler brings the temperature down to condensation. The series solution is illustrated in Figure 4-4.

Figure 4-4. Series solution



The other option is to extract a fraction of the pre-cooling fluid flow rate, and cool it in the heat pump evaporator placed in parallel with the after-cooler. Both the heat pump evaporator and after-cooler cool the pre-cooling fluid to condensation temperature, before it enters the condenser. The parallel solution is shown in Figure 4-5.

Figure 4-5. Parallel solution



Parallel solution

With the CO_2 removal process requiring heat at 115°C as heat sink and ΔT_{min}=5°C, the working fluid has to condense at 120°C in the heat pump condenser. The vapour pressure of n-butane at this temperature is 22.3 bar. This is therefore specified as the compressor outlet pressure.

The working fluid shall evaporate at 20.4°C, and the valve outlet pressure is therefore specified to be 2.1 bar.

A multivariable controller is used to determine the duty of the evaporator and the n-butane flow rate that gives a heat pump condenser duty of 76.5

MW and at the same time ensures that no liquid is formed in the compressor. The obtained evaporator duty is then used to determine the fraction of the pre-cooling fluid that has to be used in the evaporator.

It is necessary to overheat the working fluid to some degree, in order to avoid entering the two-phase region in the compressor. The mass flow rate is maximized with respect to ensure the sufficient overheating.

The simulation model with stream data are found in Appendix B.6.

Series solution

In this solution, the entire pre-cooling flow rate (472 kg/s) is utilized.

The specifications for the high-pressure side of the heat pump are the same as for the parallel solution; the working fluid is to condense at 120°C, and the compressor outlet pressure is therefore 22.3 bar.

Which temperature the pre-cooling fluid is cooled to in the evaporator is stepwise reduced. The evaporator duty is thereby increased, but since the temperature that the working fluid has to be evaporated at is also reduced to obey ΔT_{min}, the COP is lower. This is a process of trial and error. The result is the heat pump evaporator exit temperature of the pre-cooling fluid, which gives a sufficient evaporator duty that enables the heat pump to cover the heat demand of the CO_2 removal process.

As in the parallel solution, overheating is also necessary here, which limits the mass flow rate of the working fluid.

The simulation model with stream data are found in Appendix B.7.

4.2.3 Case 2 – lean amine cooler as heat source

The lean amine cooler rejects 35.8 MW to seawater, as the lean amine is cooled from 81.1°C to 44.1°C.

As this heat source rejects the heat at a higher temperature than the pre-cooling compressor after-cooler, a higher COP is expected for this heat pump.

The duty (35.8 MW) is specified to be the evaporator duty. In this case, the working fluid has evaporate at 39.1°C, while the condensation still occurs at 120°C, as for case 1. The vapour pressure of n-butane at 39.1°C is 3.7 bar, and this is specified as the valve outlet pressure. The compressor outlet pressure is 22.3 bar, as in case 1.

As for case 1, some overheating of the working fluid is necessary, and this limits the mass flow rate of n-butane.

The simulation model with stream data are found in Appendix B.8.

4.2.4 Results and discussion

Case 1

The results from the simulations of the heat pump using the pre-cooling compressor after-cooler as heat source are shown in Table 4-3 and Table 4-4.

For the parallel solution, an evaporator duty of 34.9 MW is needed for the heat pump to be able to deliver 76.5 MW to the CO_2 removal. This is equivalent to extracting 82.1% of the pre-cooling fluid flow, and passing it through the heat pump evaporator instead of the after-cooler. This is illustrated in Figure 4-6.

A COP of 1.84 is fairly decent for such a large heat pump, with a relatively large temperature lift. It obtains 46.6% of the maximum COP of 3.95.

It might be impractical that such a large percentage of the pre-cooling fluid flow rate has to be extracted in order for the heat pump to be able to supply the CO_2 removal heat demand.

Although less than for direct electric heating, a considerable quantity of electric power is necessary to run the heat pump compressor. This power has to be imported from the grid.

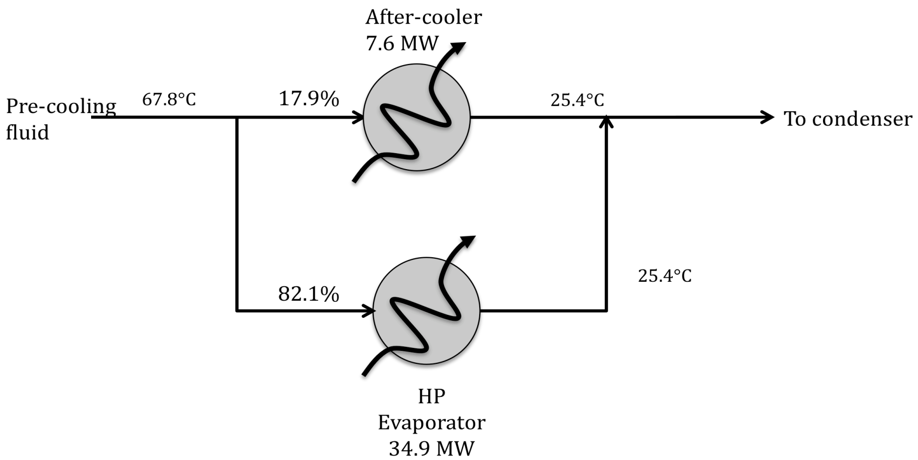
The mass flow rate of the working fluid is large – 365.6 kg/s.

Using 100% of the pre-cooling flow rate in the heat pump evaporator gives an evaporator duty of 42.5 MW. This heat pump is able to deliver 93.1 MW, which represents the maximum, using the entire pre-cooling compressor after-cooler as heat source.

Table 4-3. Case 1 – parallel solution – simulation results

Evaporator duty	Condenser duty	Compressor work	COP	Pre-cooling flow rate in HP evap.
MW	MW	MW	-	% of total
42.5	93.1	50.6	1.84	100
37.5	82.1	44.6	1.84	88.2
34.9	76.5	41.6	1.84	82.1
32.5	71.1	38.6	1.84	76.5

Figure 4-6. Case 1 - parallel solution - result



The series-solution is able to cover the heat demand of the CO_2 removal when the pre-cooling fluid is cooled to approximately 30.2°C in the heat pump evaporator, before entering the "new" after-cooler. This means that the evaporator will assume most of the duty (37.6 MW) of the original after-cooler duty. The "new" after-cooler becomes relatively small. This is illustrated in Figure 4-7.

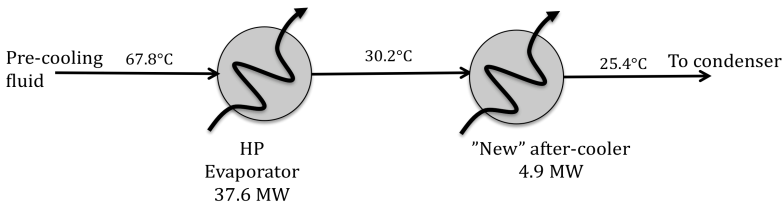
Because of a smaller temperature lift than in the parallel solution, a somewhat higher COP is obtained. The electric power needed to run the compressor is also a little lower. The obtained COP is 47.5% of the maximum COP of 4.15.

Mass flow rate of n-butane is 365.7kg/s. Because of the higher temperature/pressure the volumetric flow rate (61.8 m^3/s) at the compressor inlet is less than for the parallel solution.

Table 4-4. Case 1 – series solution – simulation results

Evap. Temp. Out	Evaporator duty	Condenser duty	Compressor work	COP
°C	MW	MW	MW	-
40.0	27.8	49.6	21.8	2.28
35.0	32.8	62.3	29.5	2.11
30.2	37.6	76.5	38.9	1.97
30.0	37.8	77.0	39.2	1.96

Figure 4-7. Case 1 - series solution - result



Case 2

The results from the simulations of the heat pump using the lean amine cooler as heat source is given in Table 4-5.

This heat pump is only capable of delivering 60.8 MW, and is thereby not able to cover the CO_2 removal heat demand alone.

The heat pump obtains a COP of 2.43 (50% max COP=4.86), which is the best of the simulated alternatives. A COP of 2.43 means that less than half the electric power is needed in the compressor to supply the heat, compared to direct electric heating.

Table 4-5. Lean amine cooler as heat source – simulation results

Evaporator duty	Condenser duty	Compressor work	COP
MW	MW	MW	-
35.8	60.8	25.0	2.43

The heat pump capacity could be utilized for the CO_2 removal process, by using it in combination with an electric heater of 15.7 MW. This solution would give a power demand of approximately 40.7 MW.

Another way to utilize the heat pump capacity is to supply the remaining 15.7 MW with another heat pump, e.g. the parallel variant of the heat pump using the pre-cooling compressor after-cooler as heat source. This heat pump can supply 15.7 MW by extracting only 16.8% of the pre-cooling fluid, with a power demand of 8.5 MW. This solution would give a total power demand of 33.5 MW to cover the CO_2 removal heat demand of 76.5 MW.

Alternatively, the heat delivered by this heat pump could be used for other, less heat demanding processes at Melkøya.

Use of heat pumps at Melkøya

The simulations confirm that use of heat pumps at Melkøya to cover parts of the heat demand is theoretically possible.

Heat pumps at Melkøya can cover the heat demand of the CO_2 removal process, which is the largest heat consumer. By supplying these 76.5 MW with heat pumps, 45.8% less heat is needed from the hot oil system. However, the heat demand is replaced with a power demand in the range of 33.5-41.6 MW, which has to be imported from the grid.

If the hot oil is heated by exhaust gas from the gas-fired furnaces, covering the CO_2 removal heat demand with heat pumps would result in a 45.8% reduction in gas consumption and thereby CO_2 emission.

Use of biomass-fired furnaces could become more realistic in combination with a heat pump covering the CO_2 removal process, as the fuel demand is significantly reduced.

Heat pumps are also beneficial in case of full electrification of the LNG plant. In addition to the existing power demand of 215 MW, the total power demand would be approximately 124.2 – 131.4 MW to cover the heat demand, instead of 167.2 MW.

With the series solution using the PCC after-cooler as heat source as basis, the result is as given in Table 4-6.

Table 4-6. Heat pump covering the CO_2 removal heat demand

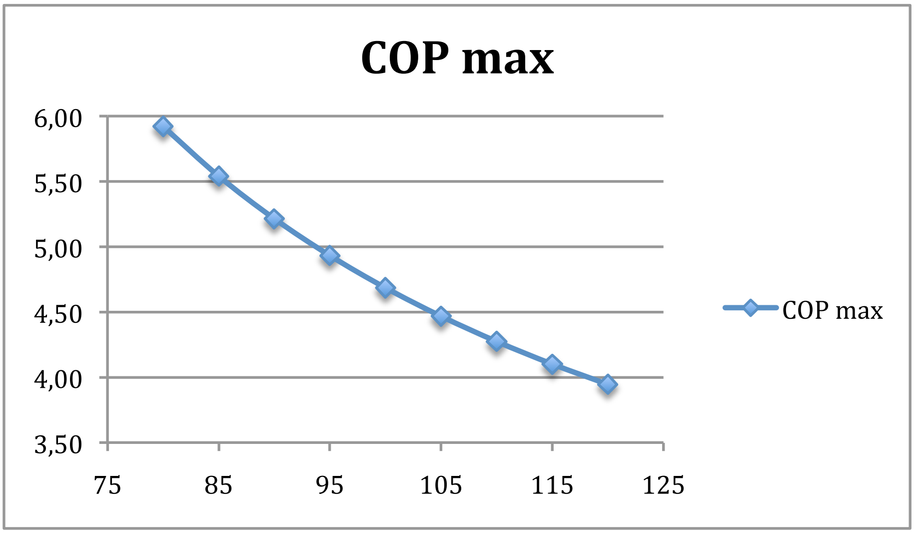
	Fuel consumption (ton/year)	Fuel cost (mill.NOK/year)	CO_2 emissions (ton/year)	CO_2 cost (mill.NOK/year)	Power demand (MW)	El.cost (mill.NOK/year)	Total cost (mill.NOK/year)
Heat pump + gas fired furnaces	56 000	47,4	152 000	53,2	38.9	138,6	239,2
Heat pump + electric heaters	0	0	0	0	206.1	461,9	461,9
Heat pump + pellets-fired furnaces	187 000	268,8	0	0	38.9	138,6	407,4

Improvements/future work

It should be noted that these simulations, with the chosen heat sources, chosen working fluid and assumptions, are just examples of potential use of heat pumps at Melkøya. There are a number of potential improvements to the simulated heat pumps, and some of them are discussed below.

The main problems with obtaining a high COP is the high temperature of the heat demanding process, 115°C, and the low temperatures of the heat sources. There is little to be done with the already existing heat sources, and it is therefore natural to assess if something could be done with the heat sink. Figure 4-8 shows how the maximum COP varies with the working fluid high temperature for case 1 – parallel solution. If the amine regeneration temperature in the stripper could be lowered to 100°C, the working fluid would have to condense at 105°C, resulting in a max COP of approximately 4.5. Assuming that 47 % of this is obtained, as the simulated case, the heat pump would get a COP of 2.12.

Figure 4-8. Max COP as function of T_h



Use of other working fluids should be investigated. Other working fluids might make the heat pump benefit from compression in multiple steps with inter-cooling.

In general, it is necessary with high working fluid mass flow rates in order to receive and reject large amounts of heat. N-butane has relatively low capacity, and the mass flow rates become very large. Due to low vapour density of n-butane at the relevant pressures and temperatures, the result is large volumetric flow rates. Working fluids with higher vapour densities at the relevant temperatures would reduce the volumetric flow rates, and thereby the necessary dimensions of equipment, and the compressor work.

It could be beneficial to use a hydrocarbon mixture as working fluid. In addition, Melkøya does not have fractionation of the LPGs, and pure n-butane is therefore not available at Melkøya.

It is assumed that the working fluid exchanges heat directly with the heat demanding process. This is not necessarily possible. If an intermediate heat carrier (steam, hot oil) is to be used, and the same ΔT is used, the working fluid would have to condense at another ΔT higher than the heat demanding process. In this case, with heat demand at 115°C, the intermediate would have to be at 120°C, and the working fluid would have to reject heat at

125°C instead of 120°C. A higher pressure-ratio in the compressor would be necessary, leading to higher duty.

The specified polytropic efficiency of the compressors is in the upper range of potential efficiencies, and somewhat lower efficiency might be expected. Choosing an efficiency in the lower end of realistic efficiencies would have given more conservative simulations.

The choice of compressor efficiency affects the capacity of the heat pumps in multiple ways, and the effect of different efficiencies should be studied.

The need for overheating of the working fluid (n-butane) is dependent on the compressor efficiency. Lower efficiency would lead to less, or no need for overheating to avoid the two-phase region. This allows a higher mass flow rate, which leads to potentially higher heat deliveries. Lower compressor efficiency would however at the same time result in higher compressor duty.

The applied ΔT_{min} is just an assumption, and the effects of this should also be assessed closer. Heat transfer through a temperature difference in the heat exchangers results in losses, and it is therefore a desire to minimize ΔT. However, ΔT_{min} affects the size of the heat exchangers; a smaller ΔT has to be compensated for by larger area or better overall heat transfer coefficient.

The choice of ΔT_{min} determines the pressure levels of the heat pump working fluid, and a smaller ΔT would lead to a lower pressure ratio in the compressor, which again results in less work.

Use of a MVR heat pump should also be evaluated.

5 Integration with the existing plant

In this section, integration with the existing LNG plant and aspects concerning the practical feasibility of the simulated heat generation alternatives is discussed.

Location of the relevant processes, configuration of the systems, size of equipment, space requirements, need for new equipment, safety etc. has so far not been taken much into consideration when evaluating the options.

Located at an island, the LNG plant has limitations with respect to area. Most of the gas processing and LNG equipment is built very compact at the barge. The five gas turbines and the hot oil heat recovery units are also located at the barge.

Removing the large gas turbines will release some area, which could be suitable for the new heat generation processes.

For the existing Train I, implementation of the new power system and heat generation processes will require modification of the existing LNG plant. For a future Train II, the new heat and power systems can be implemented when building the new process line.

5.1 Furnaces fired with natural gas

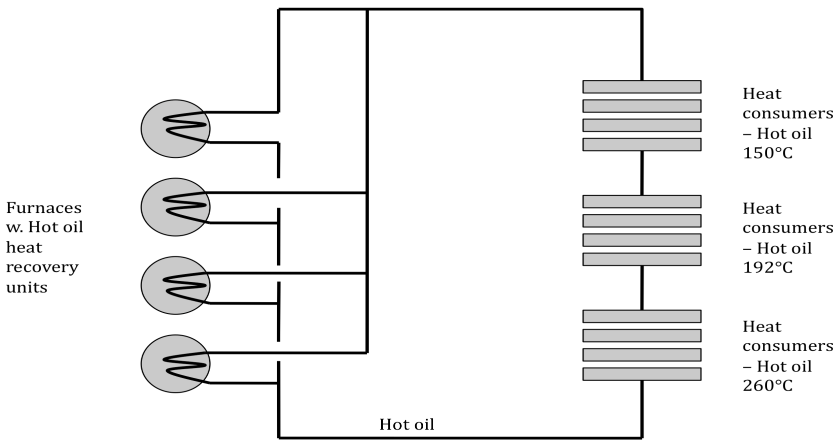
Using furnaces to provide Melkøya with such large amount of heat will require a significant area, and it is necessary to find a suitable location for them, as well as finding a solution on how the furnaces should be connected to the hot oil system.

The perhaps most logic solution would be to place the furnaces at the barge, where the gas turbines are currently located. Here the infrastructure for the natural gas as fuel is already available. This is also already the location where the hot oil is heated. Placing the furnaces with the hot oil heat recovery here would minimize the need for modification of the fuel gas supply system, as well as the hot oil system.

If the hot exhaust is to be cooled further before released to the air, integration with the seawater distribution system or a system for utilizing the heat is also necessary.

Figure 5-1 shows an illustration of the heat generation and distribution system, with hot oil being heated in the furnaces and distributed to the process heat consumers.

Figure 5-1. Heat generation and distribution



In case of failure of one of the furnaces, at least one extra furnace should be available as back up.

5.2 Oxy- fuel furnaces with CO_2 capture

As for the furnaces burning natural gas with air to heat the hot oil, it is for oxy-combustion also necessary to find a location for the furnaces and a solution on how to integrate them with the existing hot oil system. Again, the current location of the gas turbines could be suitable.

It is necessary with specialized furnaces, burners and piping that can tolerate the high temperatures generated.

In addition to the furnaces and related equipment, an air separation plant providing pure oxygen is required. The amount of O_2 required qualifies as tonnage production, requiring a significant plant area.

It is also necessary with a system for removal of impurities from the CO_2, as well as bulk water removal.

A system for CO_2 drying, compression/pumping and transport has to be built.

5.3 Heat pump

When assessing use of heat pumps at Melkøya, some considerations regarding integration with the existing LNG plant has already been done, such as evaluating potential heat sources and heat sinks. However, the relative location of the heat source and heat sink has not been taken into consideration. Nor has need for new equipment such as heat exchangers and compressors, piping etc. or space requirements for this new equipment.

Both the pre-cooling compressor after-cooler, the lean amine cooler and the CO_2 removal process is located at the process barge. The compactness of this process area could make it challenging to find room for additional piping, new, large compressors and new heat exchangers.

Since the working fluid (n-butane) shall heat the amine directly in the heat pump condenser (the heat pump is not to be connected to the hot oil system), significant modification of the amine – CO_2 stripper/re-boiler is necessary. The amine re-boiler has to be disconnected from the hot oil system, and instead exchange heat with n-butane in the heat pump condenser. Because of the large flow rates of n-butane, large pipes and a large condenser is required, and it might be difficult to fit this in where the stripper/re-boiler is currently located. A solution to this might be to move the stripper/re-boiler, or even place a new stripper/re-boiler, outside the process barge. In this way, the n-butane piping and the condenser is kept outside of the compact process area at the barge, and instead the amine flow, which is expected to be smaller, can be re-routed out to the new stripper. Such a large modification is expected to require a turnaround.

The necessary size of the compressors suggests that they will have to be placed outside the barge.

Use of a heat pump to cover the heat demand of the CO_2 removal requires two additional heat exchangers at Melkøya; an evaporator and a condenser. Because of the heat accepted and rejected together with the high flow rate of n-butane necessary, these two units become large. In order to save money, re-use of existing units should be assessed.

Since the duty of the heat exchanger acting as after-cooler has to be significantly reduced for both the alternatives of the heat pump using the PCC compressor after-cooler as heat source (case 1), the old after-cooler might be converted to operate as the heat pump evaporator, while a new and smaller unit is installed as a new after-cooler. Alternatively, the old after-cooler could be used as heat pump condenser.

For case 2, it should be investigated if the existing heat exchanger (lean amine cooler) could be used as the evaporator, using n-butane instead of seawater, or if a new heat exchanger is necessary.

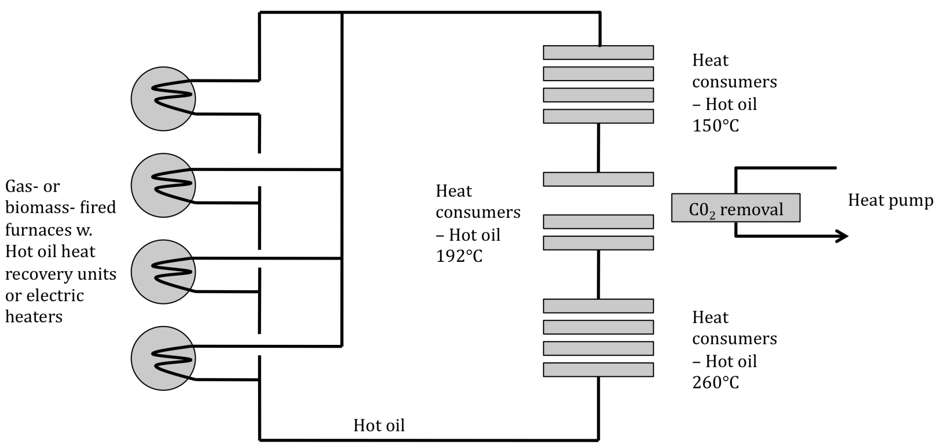
The entire LNG production is very sensitive to malfunction or failures in the heat pumps.

When using no intermediate heat carrier between the heat pump and the CO_2 removal process, the CO_2 removal would be reduced or stop if the heat pump should fail in some way. Sufficient CO_2 removal is very important to avoid freeze out of CO_2, which destroys the equipment when cooling the LNG. Should this process stop, the entire LNG production would have to be shut down.

A form of backup solution could be necessary to avoid potential production stops. An electric heater at the amine stream could be a suitable backup.

Since the heat pump solution can only be a part of a heat generation solution at Melkøya, it should be kept in mind that area and integration solutions are necessary for the remaining heat demand as well. Some solutions to this have been discussed earlier in this chapter.

Figure 5-2. Heat generation and distribution w. heat pump



6 Discussion

In this section, a discussion and a final evaluation of the five promising heat generation alternatives is made. A preliminary evaluation was made in section 3.7. The following evaluation will take the simulation results along with other aspects of choosing a heat generation process into account.

There are many aspects that have to be considered when evaluating the different heat generation processes. Since the motivation for electrification of the LNG plant is to reduce the CO_2 emission from Melkøya, it is natural to place emphasis on the emissions from the heat production. The fuel and/or electric power demand are also relevant properties of the heat generation solutions, as they directly affect the cost, as well as grid capacity and the lifetime of the LNG production. The thermodynamic goodness of the alternatives, which was the main focus in the preliminary evaluation, is also important.

Some characteristics of the heat generation alternatives that is relevant when evaluating which is the best suitable solution at Melkøya is listed in Table 6-1.

In addition to the obvious characteristics such as the CO_2 emission to air, fuel/power demand and thermodynamic goodness, aspects like the complexity and maturity of the technology, cost, operability of the processes and other practical concerns are relevant when evaluating the alternatives.

What technological risk one are willing to take, determines the necessary maturity of technology. Choosing mature, well-known technology means taking a low risk. The economical aspect includes investment cost for engineering, construction and purchase of new equipment, modification of the existing plant and cost related to fuel, emission, electric power, operation and maintenance. It is further desirable with a relatively simple process, which is easy to operate, with good stability and availability and high safety.

It is difficult to satisfy all the requested characteristics at the same time. A simple solution is perhaps not the thermodynamic best alternative, and the best option thermodynamically speaking does not necessarily have sufficiently low CO_2 emissions. Which alternative that is regarded best in total depends on what characteristics that is valued highest. The objective of this thesis is mainly to find the heat generation solution with lowest possible CO_2 emission and optimal operability. Simple solutions, with little or zero CO_2 emission to air are therefore preferred, together with thermodynamic good alternatives. The evaluation is also dependent on whether the heat generation solution is to be implemented with the existing Train I, or a future Train II. Train II has more degrees of freedom, since it is only under development. The practical difficulties discussed are therefore less relevant for Train II.

Electrification of the LNG plant will itself reduce the CO_2 emissions from Melkøya significantly, almost independently of the additional heat generation method. However, the choice of heat generation method can contribute to even lower, and even zero CO_2 emissions.

Although significantly reduced compared to the existing energy-plant at Melkøya, the options with furnaces fired with natural gas (both with and without use of heat pumps) still emits CO_2. The remaining alternatives emits close to zero CO_2.

The natural gas-fired options are therefore not suitable if it is aimed for a zero CO_2 emission solution for the existing Train I. If however a reduction in CO_2 emission is satisfactory, the gas-fired furnaces provide a sound solution to heat generation at Melkøya.

Furnaces fired with natural gas and air to produce heat benefits from utilizing simple, mature and well-known technology. Concerning the thermodynamic goodness, gas-fired furnaces is one of the better solutions. Implementing gas-fired furnaces requires some modification of the fuel gas supply system as well as the hot oil system, but has a relatively low need for new equipment, except for the furnaces. The system in total has a relatively low complexity.

If zero CO_2 emission is demanded, combustion of biomass (mainly in combination with heat pumps), oxy-fuel combustion or electric heaters (also combined with heat pumps) is the relevant alternatives.

Burning the natural gas with pure oxygen instead of air (oxy-fuel combustion) has the potential to more or less eliminate the CO_2 emission to air from Melkøya. The “cost” is an increased energy demand as in addition to the approximately same gas consumption as regular gas-fired furnaces; power is needed for producing the oxygen and for compression and pumping of the captured CO_2 down into a reservoir. This additional energy demand makes this thermodynamically speaking a less favourable option. In addition to modification of the fuel gas supply system and the hot oil system, an air separation plant for O_2 production, a system for treating the CO_2, a system for compression of the CO_2 and transportation and injection is necessary when implementing oxy-combustion furnaces for heat production at Melkøya. In total, the heat generation, with the CO_2 capture and injection becomes very complex. It is also expected that finding a new reservoir suitable for CO_2 storage, building the compression/pumping-, transport- and injection system will become extremely costly, more costly than any of the other alternatives. So if the goal is a zero CO_2 emission solution, it might be more desirable to select a solution that doesn't produce CO_2 in the first place, e.g. electric heaters. Otherwise it will be a very costly solution for a relatively small amount of CO_2.

Biomass is a renewable energy resource that can, under certain assumptions, be regarded as CO_2 neutral. Use of furnaces fired with biomass could therefore contribute to an entirely CO_2 free and renewable heat solution at Melkøya. Combustion of biomass to generate heat is a relatively mature technology, but compared to combustion of natural gas, burning of biomass has a lower efficiency. In addition, using of solid fuels tends to require more effort under operation, than gaseous or liquid fuels. The major concern is however the large amounts of biomass needed to cover the heat demand at Melkøya, causing import to be necessary. Because of the large quantities of biomass, it is concluded that combustion of biomass at Melkøya has to be combined with use of heat pumps to be realistic. Logistics and storage facilities are necessary, in addition to the furnaces and modification of the hot oil system.

Direct electric heating of the hot oil also uses simple, well-known technology. In addition, the CO_2 emission is eliminated. As for the gas-fired furnaces, little new equipment is needed, besides the electric hot oil heaters, and only a modification of the hot oil system is necessary to implement this as heat generation method at Melkøya. The result is a system with low complexity. Although the efficiency of the electric heaters is very good, this is the perhaps least favourable alternative based on thermodynamics, as the losses are high since high quality energy (electricity) is transformed to low quality energy (heat at 260°C). From an operability perspective it might be an advantage with full electrification of the LNG plant. This does however require sufficient capacity of the grid.

With respect to simplicity, use of electric heaters is comparable to use of gas-fired furnaces, but electric heaters benefit from having no gas consumption and CO_2 emission. Electric power is however relatively costly. With the current price levels of electricity and cost of emitting CO_2, it makes more economic sense to emit CO_2, and pay for it, rather than use electric power from renewable energy sources.

Heat pump technology is in principle also a well-known technology, but industrial heat pumps delivering the amounts of heat and at the temperature needed at Melkøya is not regarded as conventional. Use of a heat pump at Melkøya represents the most reasonable thermodynamic choice, and results in savings in the use of natural gas (and thereby CO_2 emission), biomass or electric power from the grid, depending on what option that is chosen to cover the remaining heat demand. Another benefit from use of heat pumps is reduced need of cooling water. Installation of heat pumps does however make the heat generation process more complex, adding more rotating equipment. As discussed in the previous section, it is likely that an installation of a heat pump to cover the CO_2 removal heat demand requires modification of the CO_2 stripper.

In this report, only one heat demanding process has been considered when evaluating the potential use of heat pumps at Melkøya. It should be investigated if heat pumps can supply other heat demanding process as well, and achieve even better saving. There are also a number of possible improvements to the assessed cases.

For the existing Train I, a detailed study of the implementation of the heat pump covering the CO_2 removal heat demand is necessary to determine if it is feasible. To avoid too extensive modification of the existing LNG plant, it is suggested that priority is given to a heat pump covering the CO_2 removal heat demand.

A future Train II benefits from having more degrees of freedom, and it might be more realistic with a more extensive use of heat pumps, compared to the existing Train I.

The heat demand that is not covered by heat pumps has to be provided by the hot oil. For the existing Train I, with a heat pump covering the CO_2 removal heat demand, the optimal solution with respect to operability and cost would be, as of today, to heat the hot oil by gas-fired furnaces. For a future Train II, with several heat pumps, a potential and interesting scenario could be an entirely renewable, CO_2 neutral solution consisting of heat pumps and biomass-fired furnaces.

Table 6-1. Characteristics of the suggested heat generation methods

	CO_2 emission to air (tons/year)	Natural gas consumption (tons/year)	Biomass consumption (tons/year)	Power demand (MW)	Cost (mill.NOK/year)
Furnaces fired w/ natural gas	280 000	103 000	0	0	185.2
Oxy-fuel furnaces w/ CO_2 capture	0	99 000	0	15.8	140.2
Electric heaters	0	0	0	167.2	595.9
Heat pump (76.5 MW) + gas-fired furnaces (90.7 MW)	152 000	56 000	0	38.9	239.2
Heat pump (76.5 MW) + electric heaters (90.7 MW)	0	0	0	129.6	461.9
Heat pump (76.5 MW) + biomass-fired furnaces (90.7 MW)	0	0	187 000	38.9	407.4

7 Conclusion

Evaluation of the selected heat generation methods has shown that there are several suitable and promising solutions for use at Melkøya. In combination with import of renewable, CO_2-free electricity from the grid to power the LNG plant, all the alternatives would result in significant reductions in CO_2 emission from Melkøya.

Due to the extreme cost of establishing transport pipelines and injection system for CO_2 storage, it is recommended to avoid CO_2 capture. Instead the heat should be produced by a method with little or no CO_2 emission.

Use of heat pumps to provide heat is the thermodynamically most favourable alternative, and will reduce the total fuel/power demand and CO_2 emission. It is therefore suggested that heat pumps should be a part of the heat generation solution at Melkøya. There are however practical issues concerning implementation of heat pumps with the existing Train I, and many potential improvements to the simulated heat pump cases. There are also possibilities for extending the use of heat pumps. Further and more thorough investigation of use of heat pumps as heat providers at Melkøya is therefore recommended.

The heat demand that is not covered by heat pumps has to be provided by the hot oil, heated either by furnaces fired with natural gas or biomass, or electric heaters. This choice is dependent on the required reductions in CO_2, CO_2 cost, fuel/power price and availability, and investment cost, and a final conclusion has to be made based on predictions of these.

Allowing some emission to air, the optimal solution for the existing Train I is to combine the assessed heat pump with gas-fired furnaces. For a future Train II, a promising scenario is an entirely renewable and CO_2 neutral solution consisting of multiple heat pumps and biomass-fired furnaces.

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Appendices

A Assumptions

General

Natural gas composition: In agreement with the supervisors, the composition of the natural gas is assumed to be **95% Methane, 4% Ethane and 1% Nitrogen**. Properties of the natural gas are listed below.

Component	mole%	MW (kg/kmole)	LHV (MJ/kg)	LHV (MJ/kmole)
Methane	95,0 %	16	50,02	800,32
Ethane	4,0 %	30	47,48	1424,4
Nitrogen	1,0 %	28	0	0
Total mix	100,0 %	16,68	49,00	817,28

The composition affects the fuel consumption as well as the CO_2 emission.

The gas density is approximately 0.709 kg/Sm^3.

Combustion: For combustion of natural gas, stoichiometric and complete combustion is assumed. The result is 103 kmole CO_2 per kmole fuel, or 271.7 kg CO_2 per kg fuel.

Operational days: It is assumed that the LNG plant, with gas turbines, furnaces, compressors etc. is in operation **330** days per year.

Price estimates: In agreement with the supervisors the following price estimates has been assumed.

Electric power from the grid - 0.45 NOK/kWh

Natural gas – 0.6 NOK/Sm^3. The cost of the natural gas as fuel at Melkøya is difficult to estimate. The natural gas is to be extracted from the gas reservoirs, not bought on the market. Market price is therefore not applicable. The average sales price on Norwegian natural gas was 1.87 NOK/Sm^3 in 2009 (source: SSB - http://www.ssb.no/emner/10/06/20/ogintma/tab-2010-02-08-05.html).

The alternative would be to leave the gas in the reservoir, and produce LNG at the end of the reservoir lifetime. At today's date, this LNG has little or no value.

CO_2 taxes to The Norwegian Government/EU CO_2 emission trading cost – 350 NOK/ton of CO_2. Melkøya is regulated as an offshore petroleum facility, with respect to CO_2 emissions. The offshore petroleum installations have since 2008 been included in the EU CO_2 emission trading system. To maintain the price level of the original CO_2 tax regime, the new CO_2 tax currently forms the difference between the prices of the trading system, and the original CO_2 taxes. It is difficult to predict the future prices in the EU CO_2 emission trading system, but one estimate is approximately 40 Euros in 2020 (Source: http://www.klimakur2020.no/Templates/Public/Pages/Article.aspx?id=641&epslanguage=en).

The existing CHP

Gas turbine efficiencies: 39.8 %

Furnaces fired with natural gas

Efficiency: it is assumed that the gas-fired furnaces have an efficiency of 90 %.

Furnaces with post-combustion CO_2 capture

Additional heat demand: The additional heat demand is estimated based on the CO_2 removal from the natural gas at Melkøya, using MDEA. The CO_2 removal occurs at higher pressure than the pressure of the exhaust gas, which gives better loading, less MDEA is needed, and thereby less heat is needed to remove CO_2 from the natural gas. Scaling this heat demand linearly down to the amount of CO_2 capture from the exhaust gas might therefore be considered conservative.

76.5 MW is needed to remove 700 000 tonnes of CO_2 per year, at high pressure.

At 80% capture efficiency 0.8*293 000=234 400 tonnes of CO_2/year is to be captured, requiring (234 400/700 000)*76.5 = 25.6 MW of heat.

At 95% capture efficiency 0.95*293 000 = 278 350 tonnes of CO_2/year is to be captured, requiring (278 350/700 000)*76.5 = 30.4 MW of heat.

Oxy-fuel furnaces with CO_2 capture

Oxygen purity: It is assumed combustion with 100% pure oxygen.

Oxygen production power demand: 0.25kWh/kg O_2

Furnaces fired with biomass/waste

Efficiency: For the furnaces fired with biomass and/or waste it is assumed an efficiency of 80%.

Properties of biomass: The effective heat value (MWh/ton) and density (kg/m^3) of the biomass fuels are obtained from Table 3-5.

Price of biomass: The price (Øre/kWh) on the selected biomass fuels are obtained from Table 3-6.

Price of waste: Melkøya is expected not to have to pay for waste.

Electric heating

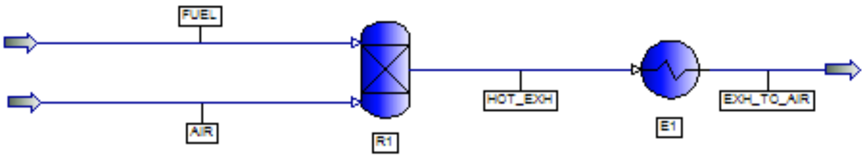
Efficiency: It is assumed that the electric heaters have an efficiency of 100%.

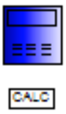
B Simulations

B.1 Furnaces fired with natural gas

Figure B 1 shows the model used for simulation of the natural gas fired furnaces, along with the main results. The corresponding stream data is found in Figure B 2.

Figure B 1: Gas-fired furnace - simulation model and results





Hx Name		E1
Duty	M*KW	0,1672

Calculator Name		CALC
Air Consumption		1728743,6250
CO2 emission		279606,8125
Fuel consumption		103156,4141

Figure B 2: Gas-fired furnace - simulation stream data

Stream Name		FUEL	AIR	HOT_EXH	EXH_TO_AIR
Stream Phase		Vapor	Vapor	Vapor	Vapor
Temperature	C	4,000	4,000	2044,709	145,000
Pressure	BAR	1,010	1,010	1,010	1,010
Total Mass Rate	KG/SEC	3,618	60,632	64,250	64,250
Total Molecular Weight		16,724	28,850	27,667	27,667
Total Molar Comp. Fractions					
METHANE		0,9500	0,0000	0,0000	0,0000
ETHANE		0,0400	0,0000	0,0000	0,0000
N2		0,0100	0,7900	0,7159	0,7159
H2O		0,0000	0,0000	0,1882	0,1882
O2		0,0000	0,2100	0,0000	0,0000
CO2		0,0000	0,0000	0,0960	0,0960

B.2 Oxy-fuel furnaces w/CO_2 capture

Figure B 3 shows the model used for simulation of the oxy-fuel furnaces. The results, and corresponding stream data is given in Figure B 4 and Figure B 5.

Figure B 3: Oxy-fuel furnace - simulation model

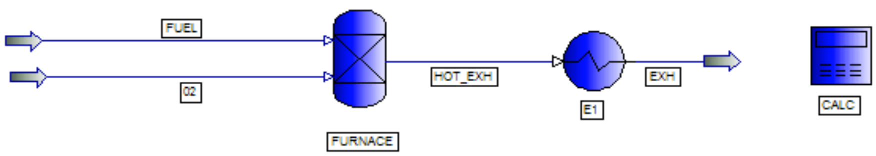


Figure B 4: Oxy-fuel combustion - simulation results

Hx Name		E1
Duty	M*KW	0,1672

Calculator Name		CALC
O2 consumption		386739,0625
CO2 "emission"		268560,9063
Fuel consumption		99079,2031
O2 prod. power demand		12,2077

Figure B 5: Oxy-fuel combustion - simulation stream data

Stream Name		FUEL	02	HOT_EXH	EXH
Stream Phase		Vapor	Vapor	Vapor	Vapor
Temperature	C	4,000	4,000	4446,940	145,000
Pressure	BAR	1,010	1,010	1,010	1,010
Total Mass Rate	KG/SEC	3,475	13,564	17,039	17,039
Total Molecular Weight		16,724	31,999	26,798	26,798
Total Molar Comp. Fractions					
METHANE		0,9500	0,0000	0,0000	0,0000
ETHANE		0,0400	0,0000	0,0000	0,0000
N2		0,0100	0,0000	0,0033	0,0033
H2O		0,0000	0,0000	0,6601	0,6601
O2		0,0000	1,0000	0,0000	0,0000
CO2		0,0000	0,0000	0,3366	0,3366

B.3 CO_2 compression and pumping

Figure B 6 shows the CO_2 compression/pumping simulation model. The stream data and results are found in Figure B 7 and Figure B 8.

Figure B 6: CO_2 compression/pumping – simulation model

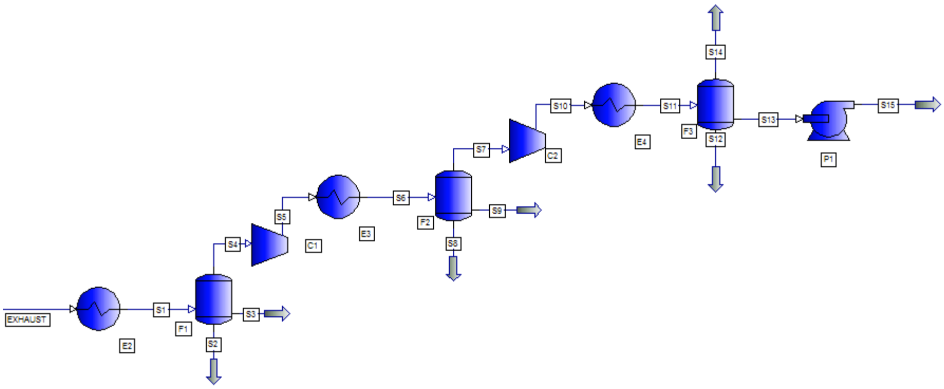


Figure B 7: CO_2 compression/pumping – simulation stream data

Stream Name		EXHAUST	S1	S2	S3	S4
Stream Phase		Vapor	Mixed	Water	Unknown	Vapor
Temperature	C	145,000	10,000	10,000	n/a	10,000
Pressure	BAR	1,010	1,010	1,010	n/a	1,010
Total Mass Rate	KG/SEC	17,039	17,039	7,515	n/a	9,525
Total Molecular Weight		26,798	26,798	18,015	n/a	43,547
Total Molar Comp. Fractions						
METHANE		0,0000	0,0000	0,0000	n/a	0,0000
ETHANE		0,0000	0,0000	0,0000	n/a	0,0000
N2		0,0033	0,0033	0,0000	n/a	0,0095
H2O		0,6601	0,6601	1,0000	n/a	0,0120
O2		0,0000	0,0000	0,0000	n/a	0,0000
CO2		0,3366	0,3366	0,0000	n/a	0,9785

Stream Name		S5	S6	S8	S9	S7
Stream Phase		Vapor	Mixed	Water	Unknown	Vapor
Temperature	C	352,449	10,000	10,000	n/a	10,000
Pressure	BAR	30,000	30,000	30,000	n/a	30,000
Total Mass Rate	KG/SEC	9,525	9,525	0,046	n/a	9,479
Total Molecular Weight		43,547	43,547	18,015	n/a	43,846
Total Molar Comp. Fractions						
METHANE		0,0000	0,0000	0,0000	n/a	0,0000
ETHANE		0,0000	0,0000	0,0000	n/a	0,0000
N2		0,0095	0,0095	0,0000	n/a	0,0096
H2O		0,0120	0,0120	1,0000	n/a	0,0004
O2		0,0000	0,0000	0,0000	n/a	0,0000
CO2		0,9785	0,9785	0,0000	n/a	0,9900

Figure B 8: CO_2 compression/pumping – simulation stream data and results

Stream Name		S10	S11	S12	S14	S13	S15
Stream Phase		Vapor	Liquid	Unknown	Unknown	Liquid	Liquid
Temperature	C	70,747	10,000	n/a	n/a	10,000	15,218
Pressure	BAR	60,000	60,000	n/a	n/a	60,000	100,000
Total Mass Rate	KG/SEC	9,479	9,479	n/a	n/a	9,479	9,479
Total Molecular Weight		43,846	43,846	n/a	n/a	43,846	43,846
Total Molar Comp. Fractions							
METHANE		0,0000	0,0000	n/a	n/a	0,0000	0,0000
ETHANE		0,0000	0,0000	n/a	n/a	0,0000	0,0000
N2		0,0096	0,0096	n/a	n/a	0,0096	0,0096
H2O		0,0004	0,0004	n/a	n/a	0,0004	0,0004
O2		0,0000	0,0000	n/a	n/a	0,0000	0,0000
CO2		0,9900	0,9900	n/a	n/a	0,9900	0,9900

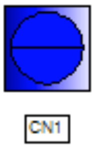
Compressor Name		C1	C2
Pressure	BAR	30,0000	60,0000
Actual Work	KW	3150,6450	357,8453
Comp Polytropic Efficiency		85,0000	85,0000
Comp Adiabatic Efficiency		80,0597	83,6745

Pump Name Pump Description		P1
Pressure Gain	BAR	40,0000
Head	M	455,4707
Work	KW	44,5374

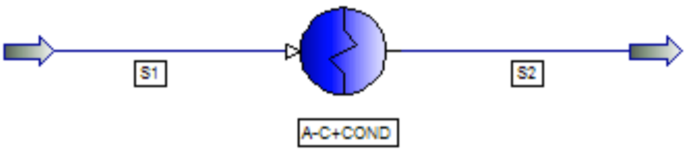
B.4 Pre-cooling cycle estimates

Figure B 9 shows the simulation of the cooling of the pre-cooling fluid through the after-cooler and condenser, where the mass flow rate and pressure is determined.

Figure B 9: PCC after-cooler/condenser – Stream data and result



Stream Name		S1	S2
Stream Phase		Vapor	Liquid
Temperature	C	67,800	10,000
Pressure	BAR	19,202	19,202
Total Mass Rate	KG/SEC	471,968	471,968
Vapor Act. Vol. Rate	M3/SEC	16,4224	n/a
Total Liquid Mole Fraction		0,0000	1,0000



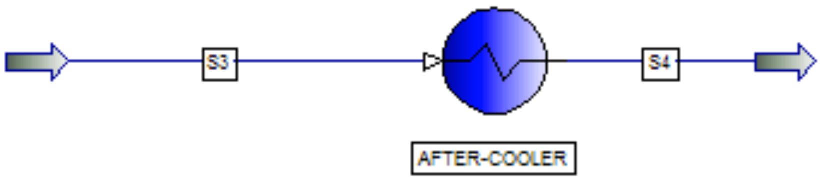
Hx Name		A-C+COND
Duty	M*KW	0,2055

B.5 After-cooler estimates

Figure B 10 shows the result from the cooling of the pre-cooling fluid flow through the after-cooler.

Figure B 10: PCC after-cooler – stream data and results

Stream Name		S3	S4
Stream Phase		Vapor	Vapor
Temperature	C	67,800	25,396
Pressure	BAR	19,202	19,202
Total Mass Rate	KG/SEC	471,968	471,968
Vapor Act. Vol. Rate	M3/SEC	16,4224	12,7020
Total Liquid Mole Fraction		0,0000	0,0000

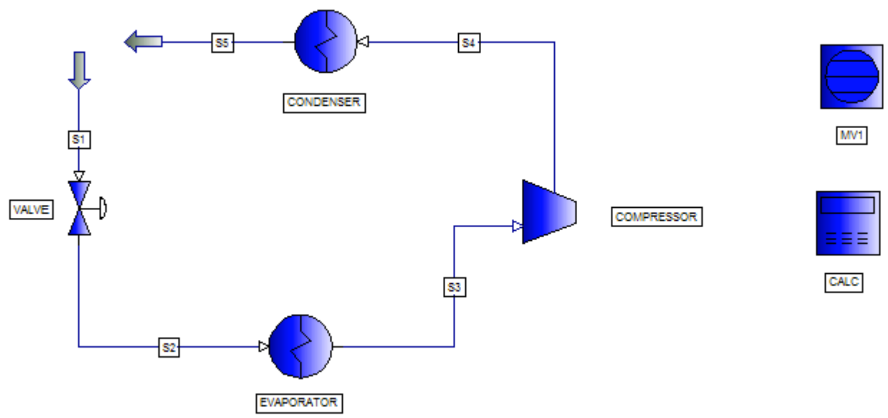


Hx Name		AFTER-COOLER
Duty	M*KW	0,0425

B.6 Heat pump case 1 – parallel solution

Figure B 11 shows the heat pump simulation model used for the parallel solution.

Figure B 11: Heat pump simulation model



The results of the simulation using the entire after-cooler duty as the heat pump evaporator duty is shown in Figure B 12. The belonging stream data are listed in Figure B 13.

Figure B 12: Max heat pump capacity - results

Hx Name		EVAPORATOR	CONDENSER
Duty	M*KW	0,0425	0,0931

Compressor Name		COMPRESSOR
Pressure	BAR	22,3070
Actual Work	KW	50571,5469
Comp Polytropic Efficiency		85,0000
Comp Adiabatic Efficiency		82,6661

Calculator Name		CALC
COP		1,8404

Figure B 13: Max heat pump capacity – Stream data

Stream Name		S1	S2	S3	S4	S5
Stream Phase		Liquid	Mixed	Vapor	Vapor	Liquid
Temperature	C	119,999	20,394	30,217	120,014	119,999
Pressure	BAR	22,307	2,099	2,099	22,307	22,307
Total Mass Rate	KG/SEC	445,000	445,000	445,000	445,000	445,000
Vapor Act. Vol. Rate	M3/SEC	n/a	65,6553	86,7607	7,0511	n/a
Total Liquid Mole Fraction		1,0000	0,2133	0,0000	0,0000	1,0000

Figure B 14 shows the result of using the multivariable controller to determine the evaporator duty necessary to obtain a condenser duty of 76.5 MW. The belonging stream data is listed in Figure B 15.

Figure B 14: Heat pump - results

Hx Name		EVAPORATOR	CONDENSER
Duty	M*KW	0,0349	0,0765

Compressor Name		COMPRESSOR
Pressure	BAR	22,3070
Actual Work	KW	41555,9922
Comp Polytropic Efficiency		85,0000
Comp Adiabatic Efficiency		82,6647

Calculator Name		CALC
COP		1,8409

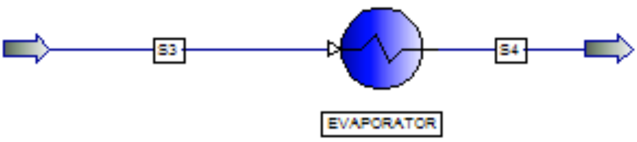
Figure B 15: Heat pump – stream data

Stream Name		S1	S2	S3	S4	S5
Stream Phase		Liquid	Mixed	Vapor	Vapor	Liquid
Temperature	C	119,999	20,394	30,265	120,054	119,999
Pressure	BAR	22,307	2,099	2,099	22,307	22,307
Total Mass Rate	KG/SEC	365,567	365,567	365,567	365,567	365,567
Vapor Act. Vol. Rate	M3/SEC	n/a	53,9358	71,2869	5,7950	n/a
Total Liquid Mole Fraction		1,0000	0,2133	0,0000	0,0000	1,0000

Figure B 16 shows the pre-cooling fluid passing through the heat pump evaporator. The obtained evaporator duty from Figure B 14 is specified in the simulation model in Figure B 16, and the controller determines the necessary flow rate of the pre-cooling fluid.

Figure B 16: Necessary pre-cooling fluid flow rate

Stream Name		S3	S4
Stream Phase		Vapor	Vapor
Temperature	C	67,800	25,396
Pressure	BAR	19,202	19,202
Total Mass Rate	KG/SEC	387,554	387,554
Vapor Act. Vol. Rate	M3/SEC	13,4851	10,4302
Total Liquid Mole Fraction		0,0000	0,0000



Hx Name		EVAPORATOR
Duty	M*KW	0,0349

B.7 Heat pump case 1 – series solution

Figure B 17: Heat pump simulation model – series solution

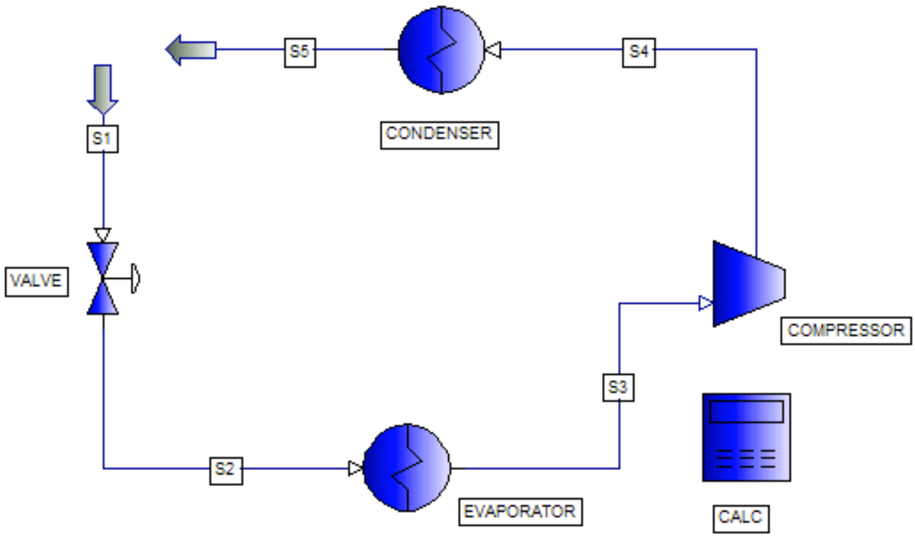
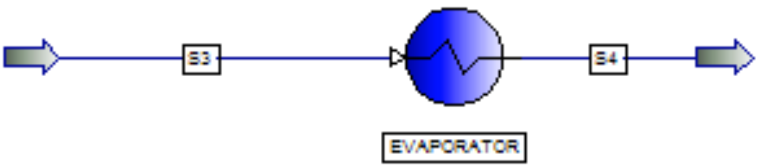


Figure B 18 shows the cooling of the entire flow rate of the pre-cooling fluid in the evaporator. The evaporator outlet temperature is specified.

Figure B 18: Evaporator duty and outlet temperature

Stream Name		S3	S4
Stream Phase		Vapor	Vapor
Temperature	C	67,800	30,200
Pressure	BAR	19,202	19,202
Total Mass Rate	KG/SEC	471,968	471,968
Vapor Act. Vol. Rate	M3/SEC	16,4224	13,1728
Total Liquid Mole Fraction		0,0000	0,0000



Hx Name		EVAPORATOR
Duty	M*KW	0,0376

Figure B 19 and Figure B 20 shows the result and stream date of the series-solution heat pump simulation, using the obtained evaporator duty from Figure B 18.

Figure B 19: Heat pump – result

Hx Name		EVAPORATOR	CONDENSER
Duty	M*KW	0,0376	0,0765

Compressor Name		COMPRESSOR
Pressure	BAR	22,3070
Actual Work	KW	38863,0430
Comp Polytropic Efficiency		85,0000
Comp Adiabatic Efficiency		82,8215

Calculator Name		CALC
COP		1,9677

Figure B 20: Heat pump - stream data

Stream Name		S1	S2	S3	S4	S5
Stream Phase		Liquid	Mixed	Vapor	Vapor	Liquid
Temperature	C	119,999	25,200	35,010	120,000	119,999
Pressure	BAR	22,307	2,443	2,443	22,307	22,307
Total Mass Rate	KG/SEC	365,700	365,700	365,700	365,700	365,700
Vapor Act. Vol. Rate	M3/SEC	n/a	45,4253	61,7710	5,7937	n/a
Total Liquid Mole Fraction		1,0000	0,2354	0,0000	0,0000	1,0000

B.8 Heat pump case 2

Figure B 21 shows the simulation model for the heat pump using the lean amine cooler as heat source.

Figure B 21: Heat pump simulation model – lean amine cooler as heat source

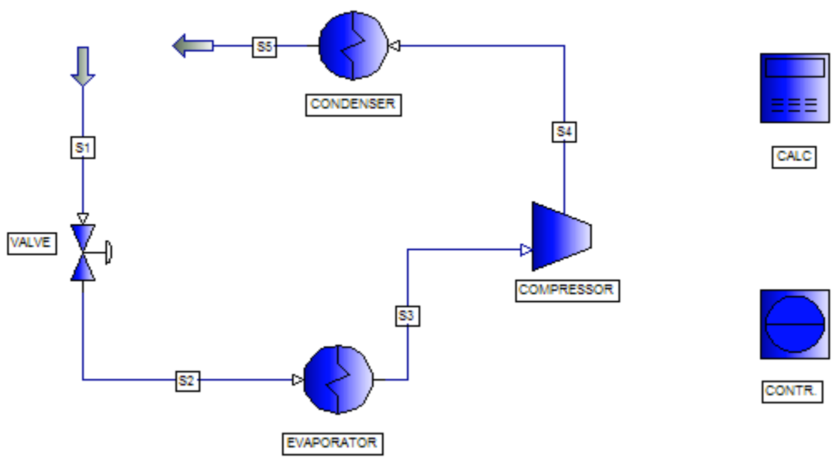


Figure B 22 shows the results of the simulation of the heat pump using the lean amine cooler as heat source. The corresponding stream data is given in Figure B 23.

Figure B 22: Heat pump – results

Compressor Name		COMPRESSOR
Pressure	BAR	22,3070
Actual Work	KW	25040,4902
Comp Polytropic Efficiency		85,0000
Comp Adiabatic Efficiency		83,2362

Hx Name		CONDENSER	EVAPORATOR
Duty	M*KW	0,0608	0,0358

Calculator Name		CALC
COP		2,4297

Figure B 23: Heat pump – stream data

Stream Name		S1	S2	S3	S4
Stream Phase		Liquid	Mixed	Vapor	Vapor
Temperature	C	119,999	39,103	48,444	120,075
Pressure	BAR	22,307	3,684	3,684	22,307
Total Mass Rate	KG/SEC	290,654	290,654	290,654	290,654
Vapor Act. Vol. Rate	M3/SEC	n/a	22,2146	33,1266	4,6085
Total Liquid Mole Fraction		1,0000	0,3032	0,0000	0,0000