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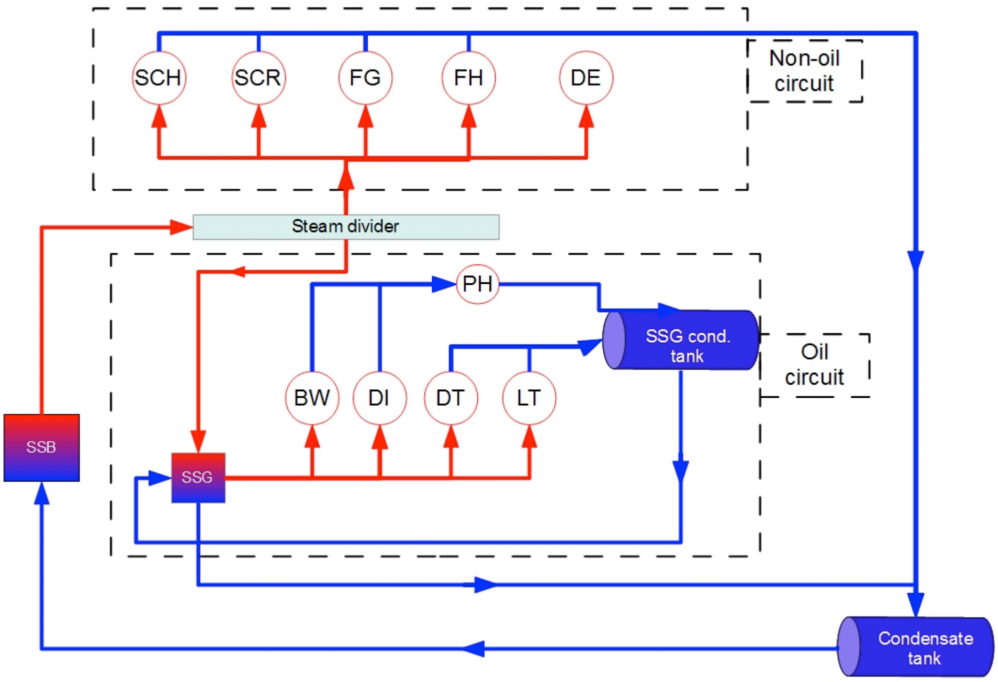

Thermodynamic analysis of the support steam system at Karlshamnsverket

Master of Science Thesis within the master programme Sustainable Energy Systems

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Department of Energy and Environment
Division of Energy Technology
CHALMERS UNIVERSITY OF TECHNOLOGY

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MASTER’S THESIS

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Cover:
The support steam system at 2 hour standby with the active heat consumers.

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ABSTRACT

Karlshamnsverket is an oil fired reserve power plant, situated in the southeast part of Sweden. The power plant consists of three units with a total capacity of $996MW_{el}$ and it operates at least 4000 hours in standby annually. The most common standby mode is the 2 hour standby. At 2 hour standby mode the power plant is required to produce electricity to the grid within 2 hours. The order for a start-up is either given by the owners or Svenska Kraftnät.

During standby the power plant needs steam to maintain readiness. Steam is supplied to the support steam system, either by an electric heater or by an oil boiler. The support steam system is divided into two circuits, a non-oil circuit and an oil circuit. Within these two circuits there are a total of ten heat consumers that are active during 2 hour standby. A heat consumer in this thesis is connected to the support steam system and is supplied with steam during 2 hour standby. Such heat consumer may be the deaerator or the heating of the oil tanks. At this time the amount of steam supplied to the heat consumers during 2 hour standby is unknown.

The oil boiler of the support steam system has during a normal year 3000 operating hours. This means fuel is consumed when the power plant is not running, thus not generating any profit, only increased costs, for Karlshamnsverket. Therefore there is a strong economic incentive to reduce the running cost of the support steam system.

In this thesis the support steam system and its heat consumers are mapped and measured at 2 hour standby to determine their respective heat requirement. The results from the measurements show that a total of 18.1MW of steam is required to operate the support steam system at maximum load.

The oil boiler of the support steam system has a maximum capacity of $13MW_{steam}$. The efficiency of the oil boiler is determined to be 85% via a created model. At this load the oil boiler has approximately 2MW of flue gas losses. This flue gas loss can be minimized, thus increasing the energy efficiency of the oil boiler.

The suggested energy efficiency measure is to install an economiser into the present oil boiler's flue gas train. To avoid flue gas condensation the economiser is placed after the current Electro Static Precipitator (ESP). The proposed capacity of the economiser is 1.4MW and delivers feed water at 80ºC to the oil boiler. This lowers the fuel consumption with approximately 46tons of LS HFO per year. The investment cost is approximated to 1.5MSEK, resulting in a payback period approximately to 4 – 5 years. The annual savings are determined to be between 300 000 – 340 000SEK.

Key words: Heavy Fuel Oil, Reserve Power Plant, Support Steam System, Economiser

Contents

Preface

I would like to extend my deepest gratitude to following people involved in this thesis,

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Abbreviations & Symbols

Abbreviations

APH	Air Preheater
$DeSO_x$	Desulphurization
ESP	Electro Static Precipitator
HFO	Heavy Fuel Oil
HD HFO	High Density Heavy Fuel Oil
HX	Heat Exchanger
KKAB	Karlshamnskraft AB
LS HFO	Low Sulphur Heavy Fuel Oil
NO_x	Nitrogen Oxide
SCH	Steam Coil Heater
SCR	Selective Catalytic Reduction
SO_x	Sulfur Oxide
SSB	Support Steam Boiler
SSG	Saturated Steam Generator
SVK	Svenska Kraftnät

Symbols

c_p	Specific heat under constant pressure	[kJ/(kgK)]
f_a	Pulse frequency of mass flow meter	[Hz]
f_b	Pulse frequency of mass flow meter	[Hz]
h	Enthalpy	[kJ/kg]
Q	Power/Heat	[kW]
q_v	Volumetric flow	[ton/h] or [m^3/h]
ρ	Density	[kg/m^3]

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1 Introduction

The Nordic energy system is dominated by two technologies, nuclear power and hydro power. During the winters of 2009 and 2010, the Nordic countries experienced a shortage of electricity. The main reason for this was because of low electricity supply from the dominating technologies (Energimyndigheten, 2010). In order to make up for the low electricity supply, reserve power plants are necessary.

The electricity grid in Sweden is monitored by the transmission system operator Svenska Kraftnät (SVK). SVK is obliged by Swedish law to have 2000MW in power reserve. This means that SVK either purchase power, domestic or foreign, or pays large industries to lower their power consumption (Svenska Kraftnät, 2011).

A reserve power plant in the Nordic energy system is characterized by a high production cost. Figure 1 shows the power production cost of the Nordic energy system versus the annual electricity consumption. The producers with the highest production cost are placed at the margin. The electricity production facilities at the margin are either coal or oil fired condensing power plants. When combusting these fuels, nitrogen oxides (NO_x) sulphur oxides (SO_x) and carbon dioxide (CO_2), are emitted. By emitting NO_x, SO_x and CO_2 the power producers must pay a fee for the amount emitted (Energimyndigheten, 2010). These costs are added to the production cost. Consequently, a power plant that uses fossil fuels has too high production cost to run as a base load.

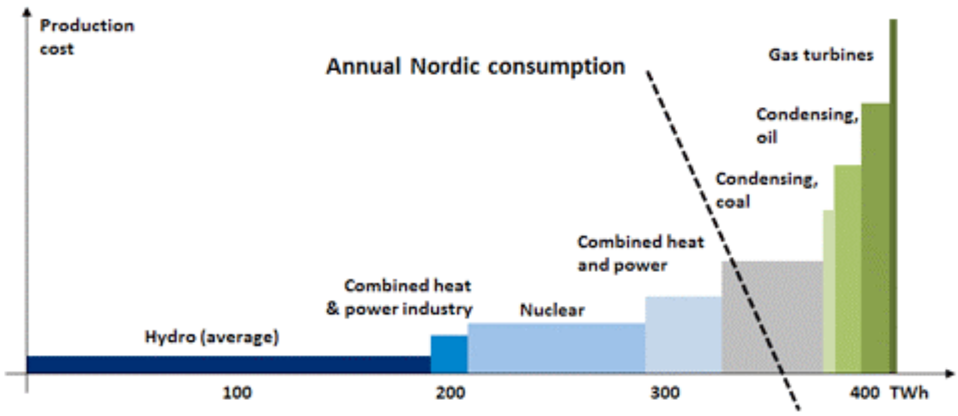

Figure 1. The production cost of the different technologies available on the Nordic energy market. The dashed line represents the annual consumption, showing that the marginal power in the Nordic countries is carbon intensive. (Nordpool, 2012)

One of these reserve power plants is Karlshamnsverket or Karlshamns Kraft AB (KKAB). KKAB is an oil fired condensing power plant in the southeast part of Sweden. Due to the high electricity production cost, the running hours of KKAB are low. If the market price exceeds the production cost and it is profitable to run KKAB then the owners have the possibility to order a start-up. If a shortage of electricity would occur, SVK may order a start-up. KKAB is owned 70% by Eon and 30% by Fortum.

The start of a power plant requires preparation to make sure that all the systems are ready for a start-up. The following levels of standby are in use at KKAB:

- 2 hour
- 8 hour
- 16 hour
- 48 hour / state of conservation

2 hour standby means that KKAB must produce electricity to the grid within two hours from the moment the order is given. The 48 hour standby means that the power plant is powered down. At KKAB there are three units, each unit with a capacity of approximately 330MW_{el}, resulting in a total plant capacity of 996MW_{el}. The steam cycle has a thermal efficiency of 42%. Table 1 presents the power output, fuel used and the numbers of 2 hour standby during 2010 for each unit.

Table 1. Power output at each unit with corresponding fuel, flue gas treatment and the number of hours in 2 hours standby during 2010.

	Power Output [MW]	**Fuel**	**Flue gas treatment**	**2 hour standby [h]**
Unit 1	330 MW	LS HFO	-	651
Unit 2	330 MW	LS HFO	$DeNo_x$	1507.8
Unit 3	330 MW	HD HFO	$DeNo_x$, $DeSO_x$, ESP	2590

All three units are fired by Heavy Fuel Oil (HFO). Unit one and two use low sulphur heavy fuel oil (LS HFO), while unit three uses High Density heavy fuel oil (HD HFO). The main difference between the two of them is the content of sulphur, where HD HFO has ten times more sulphur then LS HFO[1].

To maintain readiness at 2 hour standby, steam is used to heat up vital systems of the power plant, such as deaerated supply water or maintaining fuel oil at sufficient temperature. These vital systems are referred as heat consumers and are connected to the support steam system. Steam is supplied either by an oil fired boiler or by an electric heater. During this time the turbine cycle is offline, and the power plant is consuming energy without producing any profit. Therefore there is a strong economic incentive to lower the energy consumed or utilize it more efficiently.

[1] Personal communication with Henrik Pagels, Chief of operation at KKAB, 2011-11-16

1.1 Objectives for this master thesis

The aim of this master thesis is to find possible improvements that will lower the energy consumption or utilize the heat more efficiently. The studied system in this thesis is the support steam system at 2 hour standby. The objective of this master thesis at KKAB is to:

- Map the support steam system and its heat consumers at 2 hour standby.
- Determine the energy supplied to each heat consumer.
- Find improvements at the support steam system that will utilize the energy more efficiently.
- Calculate the economic profit of the suggested efficiency improvements.

2 Methodology

This thesis studies the support steam system at 2 hour standby. To be able to identify possible improvements an extensive analysis of the support steam system is conducted. This is done by consulting known process data and process schematics of the support steam system.

If a heat consumer is not active and not connected to the support steam system during the 2 hour standby, it is excluded from this work. The excluded heat consumers can be found in appendix A. The three turbine cycles are also excluded from this work, because they are not active during 2 hour standby. Table 2 presents the active heat consumers during 2 hour standby that are connected to the support steam system. These heat consumers are investigated and their respective heat requirements are determined.

Table 2. The heat consumers in the support steam system that is investigated in this work, with specified measurement method.

Heat consumer		Unit specific	Measurement method
SCH	Steam coil heater	Present at all units	M2
DE	Deaerator	Present at all units	M3
SCR	Heating of SCR	Connected to unit 2 and 3	M2
ESP	Heating of ESP	Connected to unit 3	M2
FG	Flue gas re-heater	Connected to unit 3	M1
OH	Facility heating	Connected to unit 1	M1
DI, BW	Heating of oil caverns(underground)	Connected to unit 1	M1
DT / LT	Heating of oil tanks (daily supply tanks and the HD storage tanks)	Present at all units	M1
PH	Pipe heating	Present at all units	M1

2.1 Measurement method

Measurements are conducted to determine the heat consumed at each active heat consumer, as stated in table 2. To determine the state of the condensate exiting from a heat consumer, three different experimental procedures are used:

- Measurement of the mass flow and temperature of the condensate (M1).
- Measurement of the power increase/decrease of the electric heater (M2).
- Measurement of the mass flow increase/decrease of the oil boiler (M3).

In addition, data from the logging system at KKAB is used in the heat balance calculations. Assumptions used in the heat balance calculations are stated in chapter 2.2.

Measurement of the mass flow and temperature of the condensate (M1)

The measurements are conducted on the primary side. To determine the heat supplied to a heat consumer, the temperature and mass flow of the condensate are measured. To conduct the measurements, following measurement instruments are used:

- Non-contact thermometer
- Portable mass flow meter

The non-contact thermometer measures the heat radiation emitted at specific point to determine the temperature. It has the advantage that the thermometer can be utilized at very hot surfaces. (Katsumi et al, 1996)

The portable mass flow meter is a so called ultra sonic flow meter, which can be directly attached to the pipe. The ultra sonic flow meter consists of two transducers and a portable mass flow meter. The transducers are mounted on the pipe, as shown in figure 2. The distance between the transducers is determined by the pipe diameter, pipe thickness and type of fluid. Transducer A emits a short sonic pulse that follows the fluid and is received by transducer B. When this occurs, it triggers transducer A to send another pulse. This results in a regular pulse frequency, f_a. The same process is duplicated in the reverse direction, creating the pulse frequency f_b. The difference between the frequencies f_a and f_b are proportional to the flow. (White, 2003)

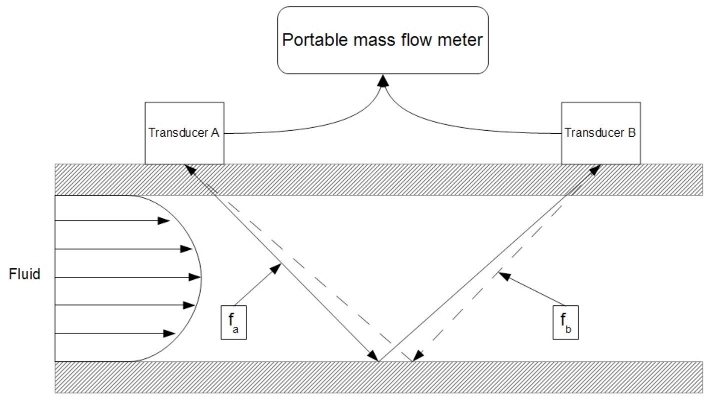

Figure 2. A cross-section of a pipe with the transducers mounted, measuring the mass flow of the fluid passing through the pipe. Where f_a is represented by the filled line and f_b is the dashed line.

The following method is used when performing the measurement of mass flow with the portable mass flow meter:

- Monitoring the mass flow for ten minutes.
- Log the mass flow every fifteen seconds, giving a total of 41 samples.

Measurement of the power & mass flow increase/decrease of the support steam boiler (M2 & M3)

Measurement method *M2* utilizes the electric heater's power capacity meter. By observing the increase or decrease of power at the electric heater, it is possible to derive the heat supplied to a specific heat consumer. The temperature of the condensate is needed to determine the mass flow at the heat consumer. The temperature of the condensate is either determined by existing equipment or by the non-contact thermometer.

Measurement method *M3* observes the increase or decrease of the mass flow rate at the oil boiler. This is possible since the oil boiler has a stationary mass flow meter installed. To determine the heat supplied to a specific heat consumer the temperature of the condensate is needed. This is determined either by the existing equipment or by the non-contact thermometer.

2.2 Modelling method

The process simulation software IPSEpro is used in the modelling work. The usage of simulation software makes it easier to apply different loading scenarios or different fluid temperatures and analyse how it affects the support steam system. IPSEpro calculates the mass- and energy balance of each component. When running a simulation all the equations are translated into a single system of equations by the software (Simtech, 2011). The results from the measurements are used as input to the components used in the model. Following assumptions are used when modelling:

- The oil boiler uses LS HFO, with a heating value of 42MJ/kg and a carbon content of 86% (See appendix C).
- The specific heat capacity of LS HFO is assumed to 1.67kJ/(kgK). (Engineering toolbox, 2011)
- Steady-state conditions.
- Assuming one condensate tank.
- No leakage of steam or condensate along the support steam system.
- Inlet air to the oil boiler is assumed to be 12ºC.
- Feed water to the oil boiler at 1 bar and 60ºC.
- The present configuration of the oil boiler is 3vol% of oxygen in the flue gas.
- Complete combustion is assumed in the combustion chamber of the oil boiler.
- The acid dew point of the flue gas is assumed to be 130ºC[2].
- The temperature drops 10ºC in the ESP.
- The stack temperature is assumed to be 60ºC.

[2] Personal communication with Kjell Nolin, Engineer at KKAB, interviewed 2011-12-06.

2.3 Loading scenarios

The support steam system and its oil boiler are subject to different loads, such as seasonal variations or steam demand variations. To simulate these variations three different loading scenarios are created. Table 3 shows the operating hours of the oil boiler from year 2008 to 2010. Using the statistics from these years, it is assumed a normal year the oil boiler operates 3000 hours with an average output of 5MW.

Table 3. Operating hours, the energy consumed of the oil boiler and the average boiler output.

Year	Operating hours [h]	Fuel consumed [ton LS HFO]	Average boiler output [MW]
2008	3119	1380	5.2
2009	3700	1750	5.5
2010	433	161	4.3

The statistics presented in table 3 are used in forming three different loading scenarios, Maximum load, normal load and low load, as described in table 4.

Table 4. The three different loading scenarios, used in simulating the different seasonal variations and steam demand of the oil boiler.

Loading scenarios	Mass flow [kg/s]	Temperature of the flue gas [ºC]	Average boiler output [MW]
Maximum load	5	360	13
Normal load	2	220	5
Low load	1.4	200	3.5

2.4 Economic evaluation method and assumptions

The economic evaluation of a possible improvement consists of a cost analysis and payback period analysis.

The cost analysis consists of running cost and the total investment cost of the possible improvements. The running cost is a summation of the fuel cost of E05 and the cost of emitting CO_2, where the fuel cost is assumed to be the majority of the running cost. LS HFO is assumed to be E05.

A sensitivity analysis of possible improvement is conducted. The price of fuel and price of emitting CO_2 is varied in order to determine the profitability in a long-term perspective. Two price levels are utilized in the sensitivity analysis, a high and a low price level. The two price levels are assumed prices of E05 and CO_2 in the year 2020 and 2035, where the policies regarding the usage of fossil fuels remain the same as in year 2011. This scenario is called “current policies” and it is developed by the International Energy Agency. The low price level is the assumed price in 2020 and the high price level is the assumed price in 2035 (International Energy Agency, 2010). Table 5 shows the high and low prices used in the economic analysis, how they are determined is stated in Appendix B.

Table 5. Assumed price of E05 and cost of emitting CO_2. (International Energy Agency, 2010)

		Price	
Fuel	**Unit**	**High**	**Low**
E05	[SEK/MWh_{fuel}]	557	466
CO_2	[SEK/tonCO_2]	292	209

The second part of the cost analysis is the total investment cost of possible improvements. In order to determine the investment cost, a manufacture of such provides an approximated investment cost. To approximate the installation and labour cost, a similar project conducted at KKAB is used. The final part is to investigate the profitability of the investment. This is determined by using a payback period analysis. The result from the payback period analysis presents how many years it will take before the investment becomes profitable (Beggs, 2009).

3 The support steam system at 2 hour standby

This chapter presents the heat consumers and the oil boiler connected to support steam system at 2 hour standby. The main purpose of the support steam system is to assist the power plant with sufficient energy to keep the power plant ready for a start-up. The support steam system is connected to the three units. The support steam system is divided into two independent circuits:

- Non-oil circuit
- Oil circuit

The reason for having two independent circuits is to avoid oil contamination in the steam. If the steam is contaminated with oil it may cause damage to the piping and other vital systems.

Steam to the support steam system is supplied either by the support steam boilers or by the high pressure turbine. Steam from the high pressure turbine is only supplied when the power plant is running. In 2 hour standby, steam is supplied either by an oil boiler at 13MW or an electric heater at 10MW. The support steam boilers produce steam at 15bar to the support steam system. The usage between the electric heater and the oil boiler depends on which of them that has the lowest running cost for the moment, and how much steam that is required by the support steam system. The oil boiler is mostly utilized during the winter since the electricity price is higher than the price of LS HFO. In summer time the electricity price is lower than LS HFO, thus increasing the usage of the electric heater.

Figure 3 shows how the steam from the support steam boilers is distributed to the oil circuit and the non-oil circuit via the steam divider, present at each unit. The condensate from the heat consumers of the non-oil circuit is led to the condensate tank. There are three condensate tanks, present at each unit. The oil circuit consists of a saturated steam generator and a condensate tank dedicated to the oil-circuit, as shown in figure 3. The saturated steam generator is a tube and shell heat exchanger.

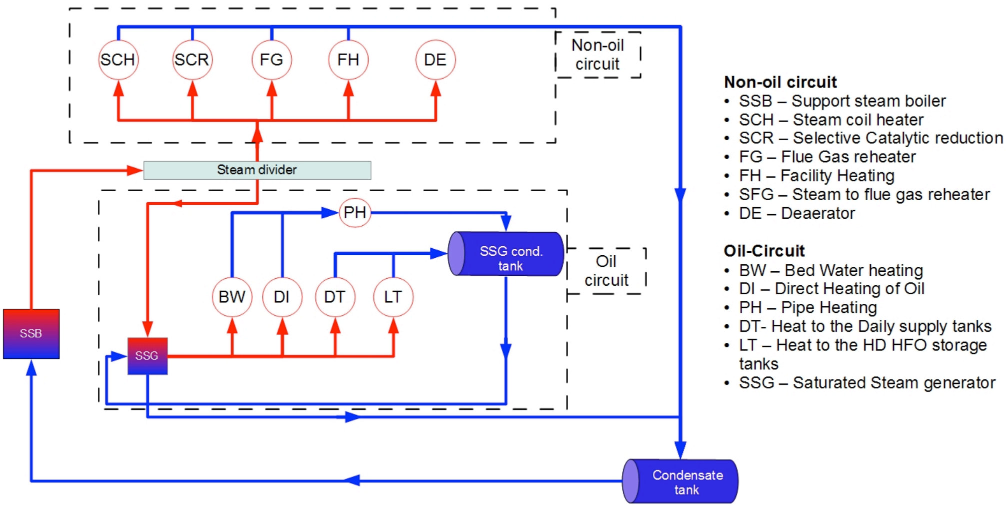

Figure 3. The schematic of the support steam system at 2 hour standby.

3.1 Oil boiler

The oil boiler is able to supply steam at a rate of 5kg/s at 15bar to the support steam system. This is equivalent to 13 MW_{steam}. Figure 4 presents the present oil boiler with its flue gas train. The boiler is supplied with feed water at 60ºC. Hot flue gas leaves the boiler at 200 - 360ºC, depending on the load, and enters the ESP. The temperature drop in the ESP is approximately 10ºC. After the ESP the flue gas enters the desulphurization-treatment ($DeSO_x$) before entering the stack. The fuel used in the oil boiler is LS HFO.

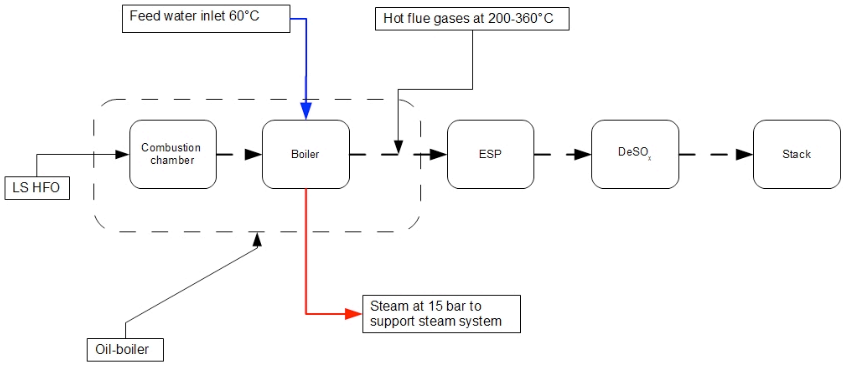

Figure 4. The present oil boiler uses LS HFO to produce steam at 15bar. Feed water at 60ºC enters the boiler and is heated up to steam at 192ºC. The flue gas train consists of ESP and $DeSO_x$-treatment.

3.2 Steam coil heater and heating of Electro Static Precipitator (ESP)

At KKAB there are two air pre-heaters (APH) at each unit. Attached to each APH is a steam coil heater (SCH). The SCH heats up the inlet air before entering the APH, shown in figure 5. Steam from the support steam boiler is supplied to the SCH. The reason for supplying steam to the SCH is to heat up the ESP. The flue gas produced from combusting HFO may cause severe corrosion if it is allowed to condense. In this case the ESP walls will be corroded. By heating up the ESP, the flue gas condensation is avoided. The ESP is ready for use when the outlet temperature of the ESP reaches 80ºC.

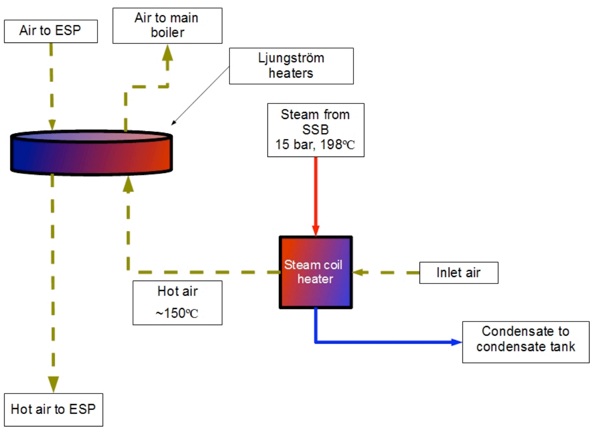

Figure 5. Inlet air is heated up in the SCH, with steam supplied by the support steam boilers. The hot inlet air is then heat exchanged in the APH. The hot air leaving the APH will then heat up the ESP, until the outlet temperature reaches 80ºC.

3.3 Deaerator

At each unit there is a deaerator, they remove dissolved gases such as oxygen from the condensed steam. Dissolved gases may cause corrosion along the feed water system. At 2 hour standby steam from the support steam boiler is injected into the deaerator in order to remove the dissolved gas.

3.4 Heating of the selective catalytic reduction (SCR)

The heating of SCR is necessary in order for the NO_x-removal process to work properly when the power plant is running. Steam supplied to the HX heats up the air that circulates through the SCR, as shown in figure 6. The air circulates through the SCR and the HX until the temperature of 150ºC is reached. The SCR is ready for use when this temperature is reached.

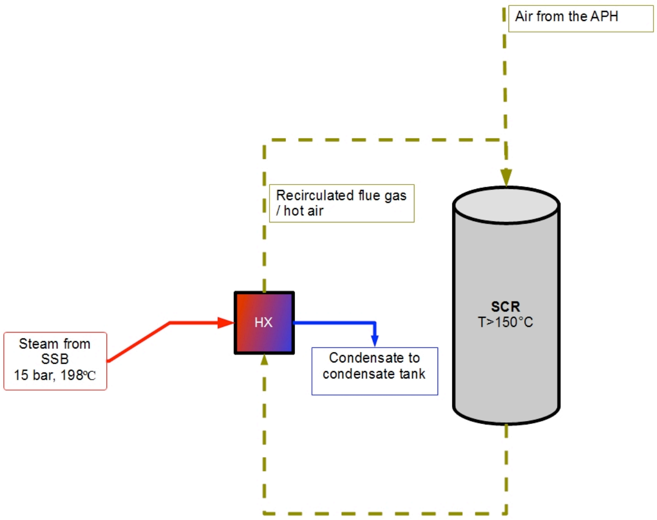

Figure 6. In order to heat up the SCR to 150ºC, steam is used to heat the air that circulates through the SCR. The SCR is ready for use when 150ºC is reached.

3.5 Flue gas re-heater

The flue gas re-heater is a large heat exchanger that heats up the flue gas before entering the stack. The temperature of the flue gas is approximately 56ºC when entering the flue gas re-heater. At this temperature the flue gas may condensate in the stack if emitted.

In 2 hour standby, two measures are done:

1. Circulate hot water in the flue gas re-heater
2. Producing steam to the flue gas re-heater

The first measure is letting hot water circulate in the flue gas re-heater to keep the flue gas re-heater free from flue gas condensate. Condensed flue gas leads to corrosion in the flue gas re-heater. Hot water at 60ºC is supplied by the condensate tank of the non-oil circuit, as described in figure 7. If the temperature drops below 60ºC, then steam from the support steam boiler is injected into the condensate tank to increase the temperature.

The second measure at 2 hour standby is to supply steam to the flue gas re-heater. This steam will heat up the flue gas produced when the power plant starts producing flue gas, until then it is only on standby. The steam is supplied by the support steam boiler until the turbine cycle is able to supply the flue gas re-heater with steam.

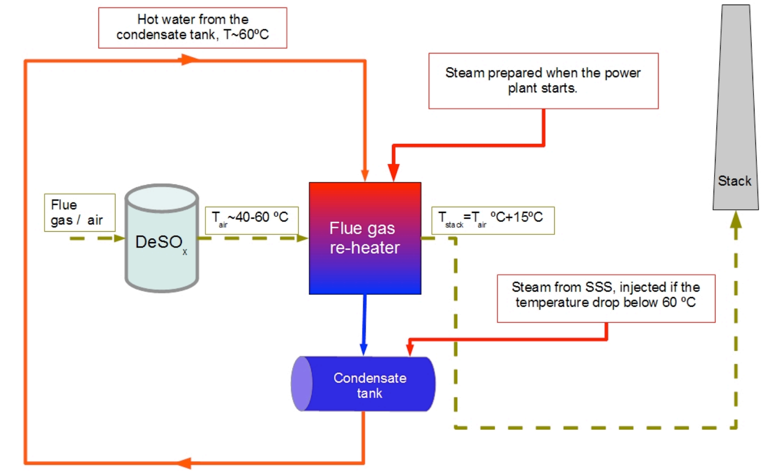

Figure 7. Hot water from the condensate tank is circulated in the flue gas re-heater in order to keep it dry. If needed steam is injected into the condensate tank to increase the temperature. Steam is led to the flue gas re-heater ready to use when the turbine cycle start.

3.6 Facility heating

The condensate from each heat consumer of the non-oil circuit is led to the condensate tank. The temperature in the condensate tank is approximately 60ºC. This hot water is used in heating the facilities at KKAB. To heat up the facilities there are two heat exchangers are (HX) utilized, presented in figure 8. The first HX heats up the cold return water with hot water from the condensate tank. If more heat is needed, steam is used in the second HX to increase the temperature. The second HX is only used if the first HX is not able to increase the cold return water to a sufficient temperature. The hot facility heating water temperature is determined by the outdoor temperature.

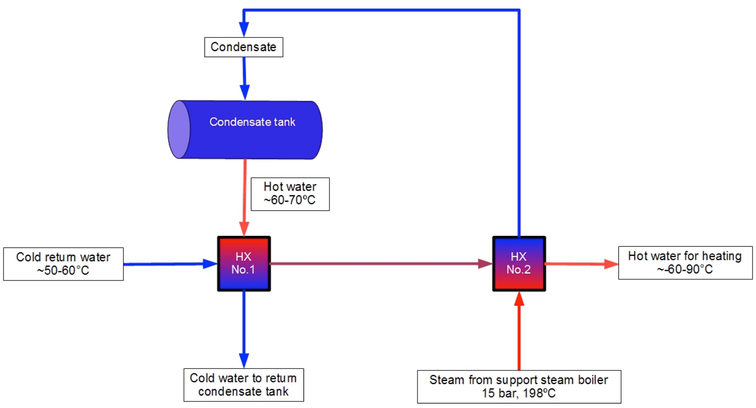

Figure 8. In HX1, heat is exchanged with the cold return water with hot condensate water. If needed the return water temperature is increased HX2 with steam. The hot facility water is then led to heat the offices and elements at KKAB.

3.7 Heating of oil tanks and caverns

At KKAB there are a total of eight oil tanks on ground level. Six of these are used to supply the burners at each unit with fuel, these six are called daily supply tanks. The final two are used as storage tanks for HD HFO. To avoid solidification of the oil in the tanks, steam is used to keep the temperature above 40ºC. Steam supplied by the saturated steam generator heats up the elements at the bottom of each tank, as shown in figure 9.

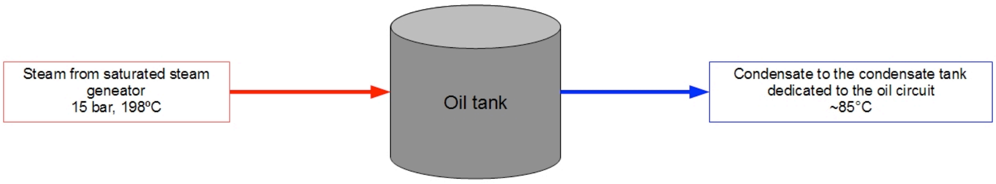

Figure 9. Steam from the saturated steam generator enters the oil tank heaters in the bottom of the tank. The condensate is then led to the condensate tank of the oil circuit.

KKAB also have seven oil caverns to store LS HFO. In these oil caverns water is used to prevent leakage of LS HFO into the groundwater. This is possible due to the fact that LS HFO has lower density than water. This water is referred to as bed water and it is also used to maintaining the oil temperature at least at 40ºC.

To avoid solidification of LS HFO in the oil caverns there are two methods for heating:

1. Heating of the bed water.
2. Direct heating of the oil in a HX.

Heating of bed water consists of a closed water circuit, presented in figure 10. The water in the closed circuit is heated by steam from the saturated steam generator. The hot water in the closed loop heats the cold bed water in the second HX.

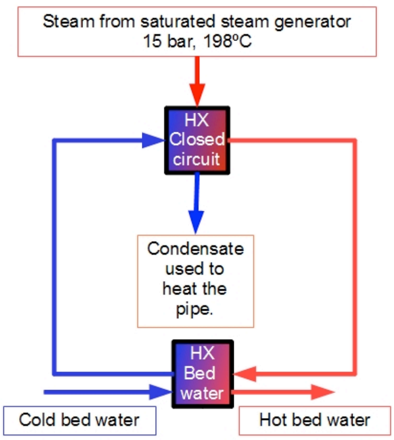

Figure 10. Steam is used in heating of the bed water via a closed circuit. The condensed steam is used to heat the pipes up to ground level.

The direct heating of the oil, presented in figure 11, utilize steam from the support steam boiler to heat exchange directly with the oil. The direct heating of the oil is used when the temperature needs to increase rapidly, while the heating of the bed water is used to maintain the temperature of the LS HFO in the oil caverns.

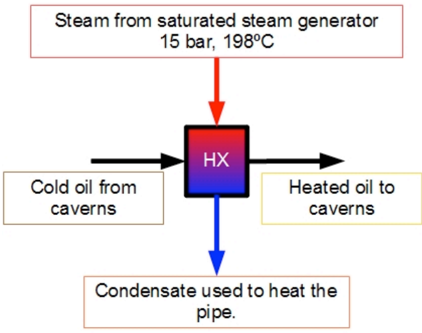

Figure 11. Steam heats up the oil in the HX. The condensate is then used in heating the pipes up to the ground level.

The condensed steam from the bed water heating and the direct heating of the oil is then transported to the condensate tank dedicated to the oil circuit. The condensed steam still contains heat. This heat is used to heat the pipes from the oil caverns up to ground level.

4 Measurement and modelling results

The following chapter contains the results from the measurements and modelling conducted. The modelling results also contain a suggested energy efficiency measure.

4.1 Measurement

The results from the measurements show that 18 136kW$_{steam}$ is required of the support steam system at full load of each consumer. The results are presented in table 6 for the non-oil circuit and table 7 for the oil circuit.

The SCH requires steam to heat the inlet air, which is used to heat up the ESP. This is the reason why SCH and ESP show the same results. The facility heating and flue gas re-heater did not consume any steam at the time of the measurement. The temperature in the condensate tank was sufficient for the facility heating and the flue gas re-heater. Hence no additional steam is required. After the deaerator there is no condensate, since the steam and dissolved gases are released into the atmosphere.

Table 6. The results from the measurement and the amount of steam supplied for each heat consumer at 2 hour standby of the non-oil circuit.

Heat consumers	**Mass flow [kg/s]**	**Temperature of the inlet fluid [ºC]**	**Temperature of the exiting fluid [ºC]**	**Measurement method**	**Heat supplied [kW]**
SCH	1.3	198.8 (Steam at 15 bar)	125 (Condensate at 15 bar)	M2	3000
Deaerator	0.67	198.8 (Steam at 15 bar)		M3	1871/deaerator Total: 5613
SCR	0.2	198.8 (Steam at 15 bar)	130 (Condensate at 15 bar)	M2	400
ESP		198.8 (Steam at 15 bar)	125 (Condensate at 15 bar)	M2	3000
Flue gas re-heater	50.7	42 (Condensate)	42 (Condensate)	M1	0
Facility heating	21.4	58 (Condensate from the condensate tank)	62 (Condensate at 15 bar)	M1	358

Table 7. The results from the measurement and amount steam supplied for each heat consumer at 2h-standby of the oil-circuit.

Heat consumers	Mass flow [kg/s]	Temperature of the inlet fluid [ºC]	Temperature of the exiting fluid [ºC]	Measurement method	Heat supplied [kW]
Bed water heating	18.2	98 (Hot water in the circuit)	77.4 (Hot water in the circuit)	M1[3]	1600/circuit Total: 3200
Direct heating of the oil	52.8 / 39.6[4]	ΔT=10 (between the inlet and outlet of the oil)		M1[4]	881.8 / 661.3 Total:1543
Daily supply tanks	0.27	198.8 (Steam at 15 bar)	84.5 (Condensate at 15 bar)	M2	600/tank Total: 3600
HD HFO-storage tanks	0.083	198.8 (Steam at 15 bar)	84.5 (Condensate at 15 bar)	M2	202/tank Total: 404
Pipe heating	0.21	80	60	M1[4]	17.6

[3] Only temperature is measured.

[4] There are two circuits with different mass flow of the LS HFO.

The total amount of steam supplied to the heat consumers at maximum capacity, is presented in figure 12. In reality this is not possible, due to the capacity limitation of the support steam boilers and the heat consumers running at the same time does not occur.

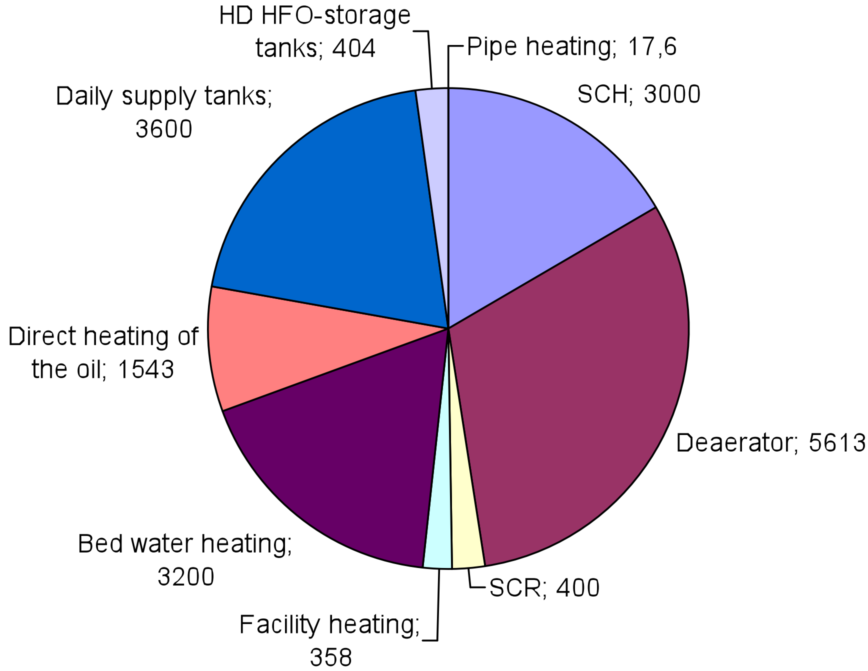

Figure 12. The steam required of the support steam system when all the heat consumers are running. Values are given in kW.

Possible source of errors

Conducting these measurements the portable mass flow meter and the non-contact thermometer are utilized. Both of these instruments presents uncertainties and are possible source of errors. The portable mass flow meter needs several input factors to compute the mass flow in a pipe. These factors are needed as input:

- Temperature of the fluid
- The thickness of the pipe
- The material of the pipe
- Pipe diameter
- The distance from pipe bends and intersection

Even though these factors are correct the mass flow data from the portable mass flow meter may present uncertainties. These uncertainties can be traced to irregularities in the velocity profile, fluid temperature or the Reynolds number. The percentage error can be ±1 to 2%, but may rise to ±5% (White, 2003).

In order to validate the portable mass flow meter, a measurement point with a known mass flow is selected. At the selected measurement point, there is a pump installed. This pump maintains the mass flow of 160m^3/h, given by process schematics. Figure 13 shows the three measurements made with the portable mass flow meter. The results shown in figure 13, reveals that there is a 2.5% uncertainty error. The result shown in figure 13 implies that the portable mass flow meter measurements are valid.

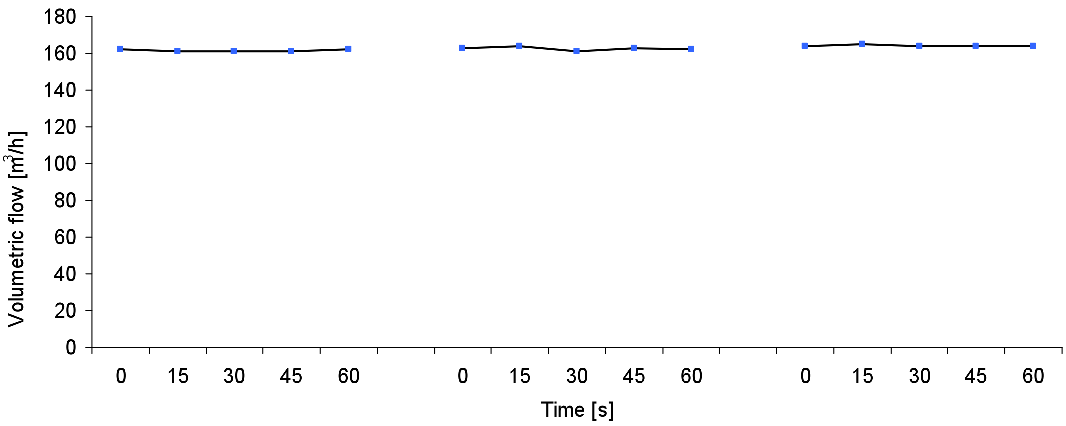

Figure 13. The graph shows the three measurements made at the selected measurement point to validate the portable mass flow meter. These measurements show a 2.5% uncertainty error.

The second measurement tool is the non-contact thermometer. To validate the non-contact thermometer, it is compared to an installed contact thermometer at KKAB. The measurement showed a ±2ºC temperature difference between the pipe wall and the measured fluid temperature. The measurement results presented in table 8, imply that measuring the pipe wall temperature is an adequate method to determine the fluid temperature.

Table 8. A comparison of temperature measured with the non-contact thermometer and the stationary contact thermometers at KKAB.

Points of measurements	Non-contact thermometer	Existing thermometers
Cold return water (at facility heating)	58 ºC	56 ºC
Deaerator condensate	64 ºC	66 ºC
Flue gas re-heater condensate	30 ºC	29 ºC

The only source of error associated with measurement methods M2 and M3 is lack of steady-state conditions during the observations i.e. other consumer might have been affected during the observation. Otherwise, the stationary measurement system is assumed to supply adequate result regarding the increase/decrease of the mass flow or power.

4.2 Modelling

Two models are created of the support steam oil boiler. The first model represents the present oil boiler and the second model is the oil boiler with the suggested energy efficiency improvement.

The model of the present oil boiler is presented in figure 4 and described in chapter 3. The boiler is supplied with feed water at 60ºC and produces steam at 15bar. By utilizing the three different loading scenarios, described in chapter 2.3. The fuel consumed and the efficiency of the oil boiler are determined and presented in table 9.

The present oil boiler does not utilize the hot flue gas which will result in a flue gas loss. At maximum load of 13MW steam production, the flue gas loss is approximately 1.95MW.

Table 9. The results of the three loading scenarios applied on the present oil boiler. The feed water inlet temperature to the oil boiler is 60ºC.

Present oil boiler	Maximal	Normal	Low
Fuel consumption [ton/yr]	3838	1425	983
Efficiency of the oil boiler[%]	85	91	92

Oil boiler with an economiser

In order to utilize the hot flue gas emitted from the oil boiler an economiser is added to the flue gas train. The reason for placing the economiser after the ESP is to avoid flue gas condensate in the ESP. Feed water at 60ºC enters the economiser and is heated by the hot flue gas. The hot water exiting the economiser is utilized as feed water to the oil boiler, hence lowering the fuel consumption. Figure 14 presents the oil boiler with an economiser added to the flue gas train.

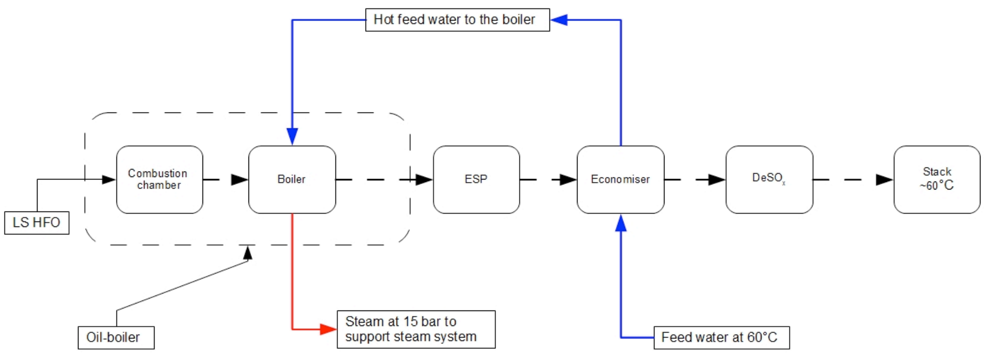

Figure 14. The oil boiler with an economiser added to the flue gas train.

The capacity of the economiser is evaluated by using the loading scenarios and three different outlet temperatures from the economiser. These are 70ºC, 80ºC and 90ºC. The results are presented in figure 15-17 and the exact figures can be found in appendix D.

Figure 15 presents the fuel consumption of the three different loading scenarios. By utilizing the economiser the fuel consumption is reduced.

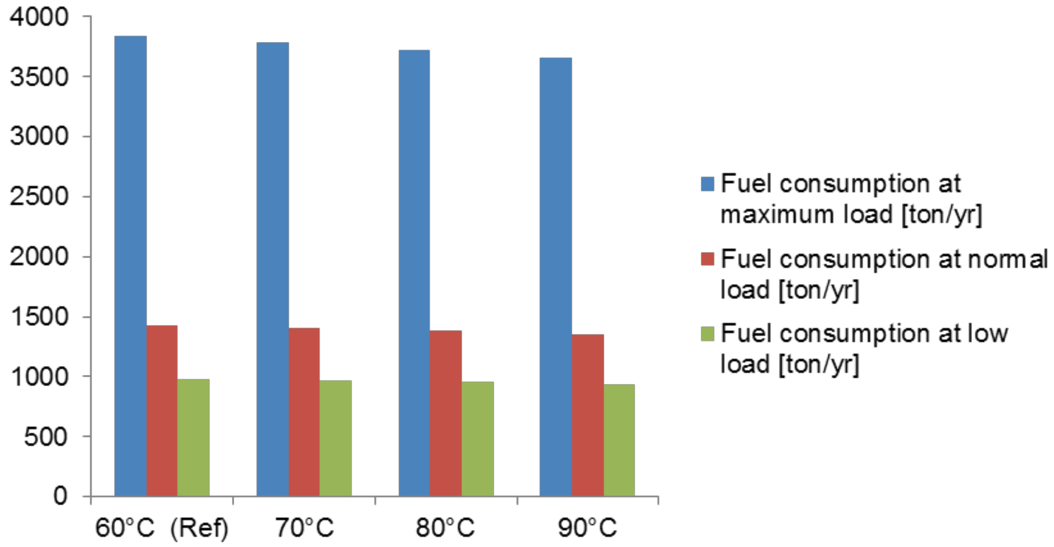

Figure 15. The fuel consumption of the oil boiler depending on which loading scenario and which feed water temperature to the oil boiler is utilized.

Figure 16 shows the feed water temperature to the oil boiler. It is shown in figure 16 that the feed water temperature at 70ºC is obtained in all three loading scenarios, but it is the lowest feed water temperature to the boiler. The feed water temperature at 80ºC to the oil boiler is possible to obtain at maximum and normal load. The feed water temperature at 90ºC to the oil boiler is only possible at maximum load. In normal and low load the feed water temperature to the boiler is 81ºC and 74ºC respectively.

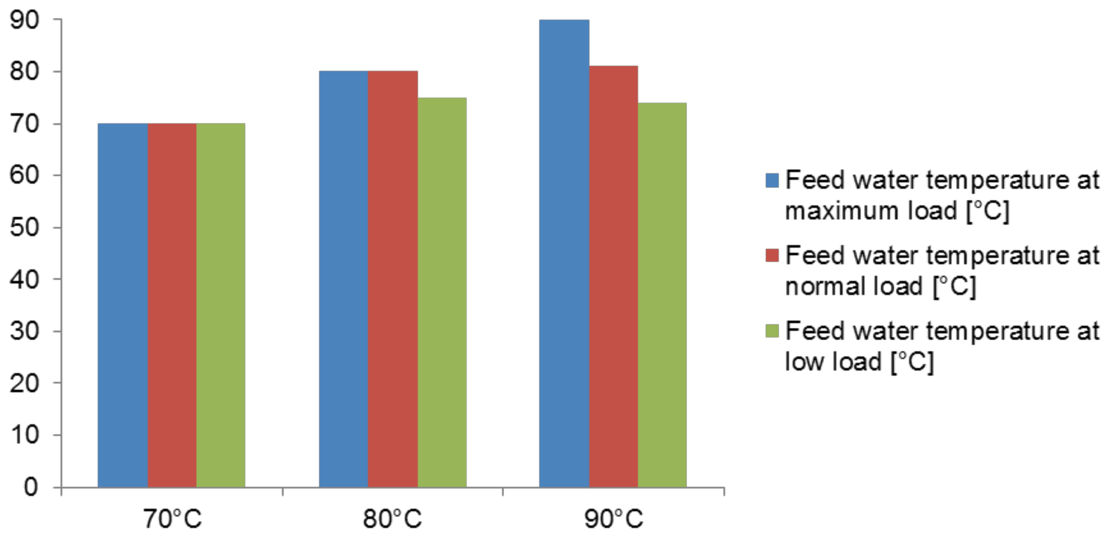

Figure 16. How the different loading scenarios affect the feed water temperature to the oil boiler.

Figure 17 show how the capacity of the economiser varies with the feed water temperature and the loading scenarios.

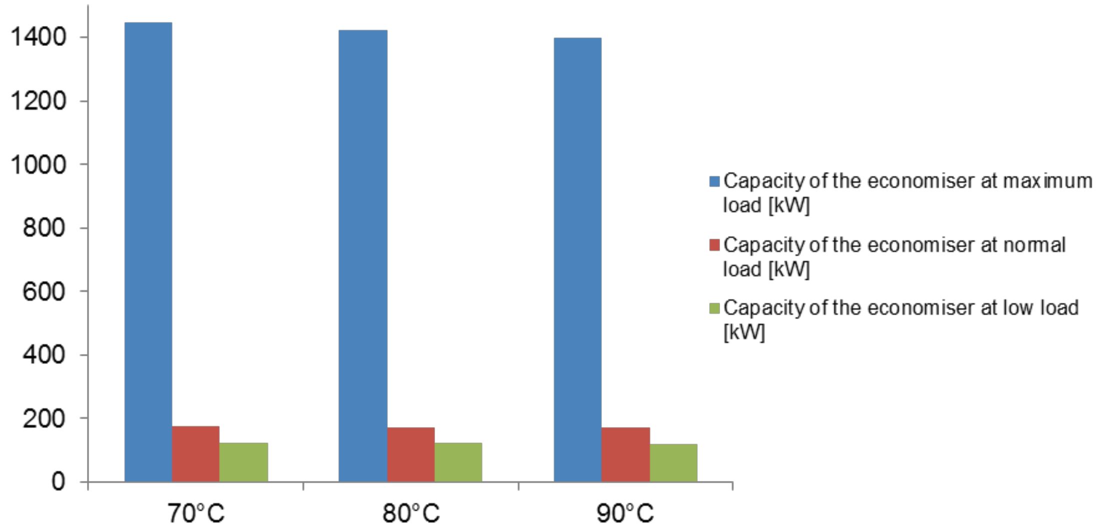

Figure 17. How the capacity of the economiser varies with the different loading scenarios and different feed water temperature.

With the given results the most feasible feed water temperature to the boiler is determined to be 80ºC, since it manages to retain high feed water temperature in all three scenarios (80ºC, 80ºC, 75ºC). The capacity of the economiser at 80ºC feed water temperature is 1421kW.

By introducing the economiser the flue gas loss is lowered from 1.95MW to 0.5MW at maximum load. The fuel consumption and CO_2 emission are reduced. Figure 18 presents the possible reduction of fuel and CO_2-emissions, with the suggested economiser installed.

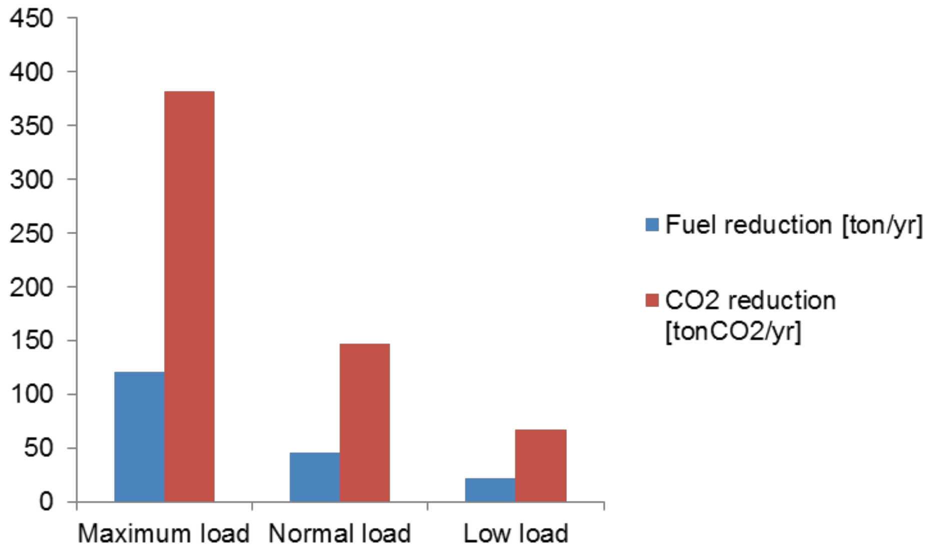

Figure 18. Possible fuel and CO_2 reduction if the suggested economiser is installed.

5 Economic analysis

The economic analysis is conducted in order to evaluate the suggested improvement and when it becomes profitable. The analysis is divided into two parts, the cost analysis and the payback period analysis.

5.1 Cost analysis

The result presented in figure 19 is the fuel and CO_2 reduction translated to running cost savings. In chapter 2.4 it is stated that the running cost is a summation of the fuel cost and cost of emitting CO_2.

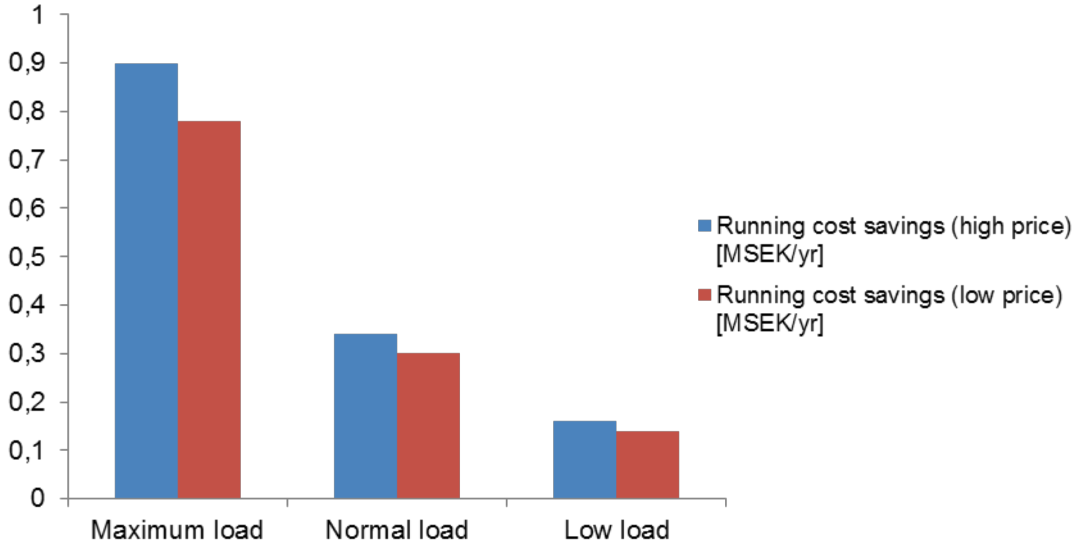

Figure 19. Based on previous figure on the possible fuel and CO_2 reduction, this figure presents the possible savings that can be made to the running cost.

Labour cost and investment costs

The cost for the economiser is approximated to 1.46 MSEK[5], given the capacity of the economiser at 1421kW. This approximation is supplied by a heat exchanger manufacture, Ekströms Värmetekniska. To estimate the installation cost of the economiser, the installation of an ion-filter conducted at KKAB is used as reference project. This project has similarities of installing an economiser, such as piping, wiring and material costs[6]. These costs are stated in table 10.

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[5] Personal communication with Björn Hintze, engineer at Ekströms Värmetekniska (2012-01-16)

[6] Personal communication with Eva Fransson, engineer at KKAB (2012-01-13)

Table 10. The projected total investment cost, including the installation cost.

Items	Cost [SEK]
Cost for one economiser	1 460 000
Piping (approximated 80 hours)	20 000
Piping material	20 000
Electrical installation	10 000
Material to the electrical installation	7 500
Cost of investment and labour	**1 517 500**

5.2 Payback period analysis

The definition of the payback period is stated in appendix B. The results presented in table 16, show that the maximal loading scenario has the shortest payback period. This is due to the higher fuel consumption. The high fuel consumption leads to higher running cost and with the usage of the economiser larger savings are possible. In the normal and low loading scenario the payback period is longer than in maximal loading scenario. This can be explained by the lower fuel consumption.

It is also shown in table 11, that this investment is not sensitive to the different fuel and CO_2 prices. In normal and low loading scenario the payback period is either prolonged with one year or two years, while in maximal loading scenario there is no difference.

Table 11. Determining the payback period for each scenario, based on the investment cost and the savings made.

Scenario	Maximum Load	Normal Load	Low Load
Total investment cost [MSEK]	1.52	1.52	1.52
Running cost savings (high price) [MSEK]	0.9	0.34	0.16
Running cost savings (low price) [MSEK]	0.78	0.30	0.14
Payback period (high price) [yrs]	**2**	**4**	**9**
Payback period (low price) [yrs]	**2**	**5**	**11**

6 Discussion

The capacity of the economiser stated in table 10 - 12, shows a small difference in capacity even though different loading scenarios and different outlet temperatures are applied. This implies the possibility to use different feed water temperature to the oil boiler depending on the current loading scenario. Assuming the oil boiler is running at maximum capacity (13MW), it is then possible to obtain 90ºC feed water temperature to the oil boiler. As long as the temperature of the feed water to the oil boiler is higher than 60ºC the fuel consumption will be lowered.

In this thesis it is assumed that the current policies will remain unchanged. This assumption is based on the lack of progress made on the last three global summits on renewing the Kyoto-protocol. Unfortunately no breakthrough is foreseen, which makes this assumption more certain in this work. Choosing this particular scenario showed that the economiser investment cost is rather insensitive to price variation of E05 and CO_2. Regardin the installation cost presented in this thesis, it should only be considered to give an indication of how much the installation cost could be.

The payback period is affected by the increase or decrease of the operating hours. If the number of operating hours increases, it would imply more fuel is consumed and more CO_2 emitted. A consequence of this is an increase of the running cost for the present oil boiler. This implies larger savings can be made due to the use of the economiser. Thus the payback period is shortened if the operating hours would increase, regardless of any loading scenarios.

7 Conclusions

In this work, the support steam system at KKAB has been studied. By mapping and measuring the support steam system at 2 hour standby, it was possible to determine the amount of steam required to $18.1MW_{steam}$.

In order to increase the energy efficiency of the support steam system, an analysis of the support steam system and the current oil boiler was conducted. This analysis showed that the lack of an economiser means approximately 2MW of hot flue gas is not utilized. A model of the current oil boiler with an addition of an economiser was simulated. The flue gas temperature and the steam flow rate are varied according to the three different loading scenarios. The three different loading scenarios simulate the different loads the oil boiler is subjected to.

In order to avoid flue gas condensation in the flue gas train, two measures were taken. The first one was to place the economiser after the ESP to avoid flue gas condensation in the ESP. The second measure was to set the temperature of the flue gas leaving the economiser to 140ºC, above the acid dew point at 130ºC.

The size of the economiser was determined by using the three different loading scenarios and three different outlet temperatures from the economiser. These three outlet temperatures are 70ºC, 80ºC and 90ºC, which enters the oil boiler in order to lower the fuel consumption. The 80ºC outlet temperature from the economiser was determined to be the most suitable economiser outlet temperature. The final capacity of the economiser was determined to be 1421kW.

The installation of an economiser would lower the fuel consumption by 46ton/yr and lower the CO_2-emission by 147tonCO_2/yr. The economic analysis shows that the investment of an economiser would be profitable within the near future. How soon this will be is very much dependent on global emission targets and future oil prices. With the present assumptions, it is likely that the payback period is 4 - 5 years. Annual savings is determined to be 330 000 - 340 000SEK.

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Personal communication

Björn Hintze, Engineer at Ekströms Värmetekniska, (2012-01-16)

Eva Fransson, Engineer at Karlshamns Kraft AB, (2012-01-13)

Henrik Pagels, Chief of operation at Karlshamns Kraft AB, (2011-11-16)

Kjell Nolin, Engineer at Karlshamns Kraft AB, (2011-12-06)

Appendix A – Excluded heat consumers

The described heat consumers are not powered during 2 hour standby.

Steam atomizer

At the start-up of the power plant, before igniting the fuel oil, it needs to atomize. The atomization process creates a mist of fuel oil, to make it possible to ignite. To atomize the fuel oil, steam is used. At start-up steam is supplied by the support steam boiler via the saturated steam generator. When the power plant is running, steam is supplied by the turbine cycle. This consumer is only used at start-ups and when running.

Oil preheater

The oil pre-heater makes sure that the fuel oil reaches the desirable viscosity before entering the burners. Experience has shown that LS HFO and HD HFO need to be heated to 100 ºC and 160 ºC, respectively. Steam is supplied by the support steam boiler at start-up, as the power plant begins producing it own steam, the support steam boiler is taken offline. This heating process is only used when the power plant is starting-up and when running, not in standby-mode.

Start ejector

At start-up of the power plant, there is a need for an under pressure/vacuum in the condenser allowing the turbine to start. If the vacuum is not established then no steam is allowed to enter the HP-turbine, since this pressure dictates the power output. When 80% of the vacuum is reached the supply of steam is shut off. Thus this consumer is only used at start-ups.

Condensate clean-up unit

The condensate clean-up makes sure that no impurities, such as salt water. If salt water is present in the condensate it may cause damages to the boiler. This system is used once every year or when needed if impurities are detected in the main supply water system.

Appendix B – Economic calculations

The amount of fuel consumed is retrieved from the simulation software. The results from the modelling of the present and the improved oil boiler are used as input in these economic calculations. It is now possible to determine the amount of fuel consumed and CO_2 emitted on an annual basis, which makes it possible to determine the running cost.

Fuel Cost

The cost of E05 is assumed to include the LS HFO, which is used in the oil boiler. The price is from the scenario called "current policies" extracted from World Energy Outlook 2010. The low price is an assumed price at year 2020 and the high price is an assumed price at 2035, presented in table 17.

Table 12. The E05 prices extracted from World Energy Outlook 2010(International Energy Agency, 2010)

	High price[USD/barrel]	Low price[USD/barrel]
E05	135	120

These in data are used to calculate the price given in USD/barrel to SEK/MWh.

- Energy content of LS HFO, 42 MJ/kg (see appendix C).
- Density of LS HFO 909 kg/m^3 (see appendix C)
- 86% Carbon content in LS HFO (see appendix C).
- 1 barrel = 159 litre
- 1 J = $2.78*10^{-7}$kWh
- 1 USD ~ 6.96 SEK (Valuta.se, 2012)

$$135\left[\frac{USD}{barrel}\right]\cdot 6.96\left[\frac{SEK}{USD}\right]\cdot\frac{1}{0.159}\left[\frac{barrel}{m^3}\right]=5909\left[\frac{SEK}{m^3}\right] \qquad B\ 1$$

The price per cubic meter is determined. Now the amount of energy per cubic meter of LS HFO needs to be determined.

$$42\cdot 10^6\left[\frac{J}{kg}\right]\cdot 909\left[\frac{kg}{m^3}\right]\cdot 2.78\cdot 10^{-7}\left[\frac{kWh}{J}\right]=10361\left[\frac{kWh_{fuel}}{m^3_{fuel}}\right]=10.6\left[\frac{MWh_{fuel}}{m^3_{fuel}}\right] \qquad B\ 2$$

The amount of energy per cubic meter is multiplied with the calculated price per cubic meter, it is possible to determine the price per MWh_{fuel}.

$$E_{05-High}=5909\left[\frac{SEK}{m^3_{fuel}}\right]\cdot\frac{1}{10.6}\left[\frac{m^3_{fuel}}{MWh_{fuel}}\right]\approx 557\left[\frac{SEK}{MWh_{fuel}}\right]$$

$$\Rightarrow E_{05-Low}\approx 495\left[\frac{SEK}{MWh_{fuel}}\right] \qquad B\ 3$$

To calculate the amount of fuel consumed the following equation is used.

$$m_{fuel}\left[\frac{ton}{yr}\right] = \dot{m}_{fuel-consumption}\left[\frac{kg}{s}\right]\cdot 3600\left[\frac{s}{h}\right]\cdot\frac{1}{1000}\left[\frac{ton}{kg}\right]\cdot 3000\left[\frac{h}{yr}\right] \qquad B\ 4$$

When the amount of fuel is calculated it is possible to calculate the fuel cost with the following equation. The parameter $E05_{price}$ is either high or low, as shown earlier.

$$Fuel_{cost}\left[\frac{MSEK}{yr}\right] = m_{fuel}[ton]\cdot 42\cdot 10^{3}\left[\frac{J}{ton}\right]\cdot 2.78\cdot 10^{-10}\left[\frac{MWh_{fuel}}{J}\right]\cdot E05_{price}\cdot 10^{-6}\left[\frac{MSEK}{MWh_{fuel}}\right] \qquad B\ 5$$

CO_2-cost

The extracted price of CO_2 from World Energy Outlook at current policy is used. In table 13 the low price level and high price level is presented. The low price is at year 2020 and the high price at year 2035.

Table 13. The CO_2 prices extracted from World Energy Outlook 2010(International Energy Agency, 2010)

	High price[USD/tonCO_2]	Low price[USD/tonCO_2]
CO_2	42	30

$$CO_{2-priceHIGH} = 42\left[\frac{USD}{tonCO_2}\right]\cdot 6.96\left[\frac{SEK}{USD}\right] = 292\left[\frac{SEK}{tonCO_2}\right]$$

$$\Rightarrow CO_{2-price\ LOW} = 209\left[\frac{SEK}{tonCO_2}\right] \qquad B\ 6$$

To determine the amount of CO_2 that is emitted, the first step is to determine how much CO_2 is emitted per kWh_{fuel}.

$$1\left[kWh_{steam}\right]\cdot\frac{1}{\eta_{SUNROD}}\left[\frac{kWh_{fuel}}{kWh_{steam}}\right]\cdot 3.6\left[\frac{MJ_{fuel}}{kWh_{fuel}}\right]\cdot\frac{1}{42}\left[\frac{kg_{fuel}}{MJ_{fuel}}\right]\cdot 86\left[\%C\right]\cdot\frac{44}{12}\left[\frac{kgCO_2}{kgC}\right]\Rightarrow$$

$$\Rightarrow CO_{2-emission}\left[\frac{tonCO_2}{MWh_{fuel}}\right] = CO_{2-emission}\left[\frac{kgCO_2}{kWh_{fuel}}\right]\cdot 10^{-3}\left[\frac{ton}{kg}\right]\cdot 1000\left[\frac{kWh_{fuel}}{MWh_{fuel}}\right] \qquad B\ 7$$

The second step is to introduce the CO_2-price along with the amount of consumed fuel.

$$CO_{2-cost}\left[\frac{MSEK}{MWh_{fuel}}\right] = CO_{2-price}\cdot 10^{-6}\left[\frac{MSEK}{tonCO_2}\right]\cdot CO_{2-emission}\left[\frac{tonCO_2}{MWh_{fuel}}\right]\cdot \qquad B\ 8$$

The final calculation to determine the total cost of emitting the cost CO_2.

$$CO_{2cost}\left[\frac{MSEK}{yr}\right] = CO_{2-cost}\left[\frac{MSEK}{MWh_{fuel}}\right]\cdot m_{fuel}\cdot 10^{3}\left[\frac{kg}{yr}\right]\cdot 42\cdot 10^{6}\left[\frac{J}{kg}\right]\cdot 2.78\cdot 10^{-10}\left[\frac{MWh_{fuel}}{J}\right] \qquad B\ 9$$

Result of the cost analysis

Table 14-16 shows the results of the running cost for each loading scenario with the current feed water temperature and the 80ºC feed water temperature. The results are derived with previously presented equations and the stated assumption, presented in chapter 2.4.

Table 14. The fuel cost, cost of emitting CO_2 and running cost at scenario M.

Maximum load		Fuel cost [MSEK/yr]		CO_2-cost [MSEK/yr]		Running cost [MSEK/yr]	
Alternative	**Fuel consumption[ton]**	**High**	**Low**	**High**	**Low**	**High**	**Low**
60ºC (present)	3838	24.9	22.2	3.5	2.5	28.5	24.7
80ºC	3717	24.2	21.5	3.4	2.5	27.6	23.9

Table 15. The fuel cost, cost of emitting CO_2 and running cost at scenario N.

Normal load		Fuel cost [MSEK/yr]		CO_2-cost [MSEK/yr]		Running cost [MSEK/yr]	
Alternative	**Fuel consumption[ton]**	**High**	**Low**	**High**	**Low**	**High**	**Low**
60ºC (present)	1426	9.3	8.2	1.3	0.9	10.6	9.2
80ºC	1379	8.9	7.9	1.3	0.9	10.2	8.9

Table 16. The fuel cost, cost of emitting CO_2 and running cost at scenario L.

Low load		Fuel cost [MSEK/yr]		CO_2-cost [MSEK/yr]		Running cost [MSEK/yr]	
Alternative	**Fuel consumption[ton]**	**High**	**Low**	**High**	**Low**	**High**	**Low**
60ºC (present)	983	6.4	5.7	0.9	0.7	7.3	6.3
80ºC	961	6.2	5.6	0.9	0.6	7.1	6.2

Definition of payback period

$$PayBackPeriod = \frac{InvestmentCost}{Cost\,Savings}$$ (Beggs, 2009) *B 10*

Appendix C – Fuel data of LS HFO

Fuel data supplied by KKAB of LS HFO.

Table 17.Fuel data of LS HFO.

Heating value [MJ/kg]	42,03
Sulphur content [%]	0,28
Density at 15°C [kg/m^3]	909,8
Carbon content [%]	86,9
Hydrogen content [%]	12,7
Sulphur content [%]	0,28
Nitrogen content [%]	0,1
H_2O content [%]	0,1
Ash [%]	0
O_2 content [%]	0

Appendix D – Results from the economiser evaluation

Table 18. The results from the loading scenario maximum load, with a supply water mass flow at 5kg/s entering the oil boiler. The flue gas temperature is 360ºC when it enters the economiser.

Maximum Load	**60ºC (Present)**	**70ºC**	**80ºC**	**90ºC**
Fuel consumption [ton/yr]	3838	3781	3717	3653
Hot water mass flow economiser [kg/s]	-	34.5	16.9	11.1
Feed water temperature to the oil boiler[ºC]	60	70	80	90
Capacity of the economiser [kW]	-	1446	1421	1398
Efficiency of the oil boiler[%]	85	94	94	94

Table 19. The results from the loading scenario normal load, with a supply water mass flow at 2kg/s entering the oil boiler. The flue gas temperature is 220ºC when it enters the economiser.

Normal Load	**60ºC (Present)**	**70ºC**	**80ºC**	**90ºC**
Fuel consumption [kg/s]	1426	1403	1379	1355
Hot water mass flow economiser [kg/s]	-	4.2	2.1	1.4
Feed water temperature to the oil boiler[ºC]	60	70	80	81
Capacity of the economiser [kW]	-	175.6	172.3	169.7
Efficiency of the oil boiler[%]	91	94	94	94

Table 20. The results from the loading scenario low load, with a supply water mass flow at 1.4kg/s entering the oil boiler. The flue gas temperature is 200ºC when it enters the economiser.

Low Load	**60ºC (Present)**	**70ºC**	**80ºC**	**90ºC**
Fuel consumption [kg/s]	983	972	961	940
Hot water mass flow economiser [kg/s]	-	2.1	1.02	0.67
Feed water temperature to the oil boiler[ºC]	60	70	75	74
Capacity of the economiser [kW]	-	122.9	120.8	118.8
Efficiency of the oil boiler[%]	92	94	94	94